Displaying title 40, up to date as of 5/07/2024. Title 40 was last amended 5/07/2024.

There have been changes in the last two weeks to Subpart OOOOb.

Title 40 —Protection of Environment
Chapter I —Environmental Protection Agency
Subchapter C —Air Programs
Part 60 —Standards of Performance for New Stationary Sources

ENHANCED CONTENT - TABLE OF CONTENTS

Subpart OOOOb—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022

Source: 89 FR 17043, Mar. 8, 2024, unless otherwise noted.

§ 60.5360b What is the purpose of this subpart?

(a) *Scope.* This subpart establishes emission standards and compliance schedules for the control of the pollutant greenhouse gases (GHG). The greenhouse gas standard in this subpart is in the form of a limitation on emissions of methane from affected facilities in the crude oil and natural gas source category that commence construction, modification, or reconstruction after December 6, 2022. This subpart also establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities in the crude oil and natural gas source category that commence construction, modification, or reconstruction after December 6, 2022.

(b) ***Prevention of Significant Deterioration (PSD) and title V thresholds for Greenhouse Gases.***

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered the pollutant that otherwise is subject to regulation under the Clean Air Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to GHG emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to GHG emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 71.2.

(c) ***Exemption.*** You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

§ 60.5365b Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (i) of this section, that is located within the Crude Oil and Natural Gas source category, as defined in § 60.5430b, for which you commence construction, modification, or reconstruction after December 6, 2022. Facilities located inside and including the Local Distribution Company (LDC) custody transfer station are not subject to this subpart.

(a) Each well affected facility, which is a single well drilled for the purpose of producing oil or natural gas.

(1) In addition to § 60.14, a “modification” of an existing well occurs when:

(i) An existing well is hydraulically fractured, or

(ii) An existing well is hydraulically refractured.

(2) For the purposes of a well affected facility, a liquids unloading event is not considered to be a modification.

(3) Except as provided in § 60.5365b(e)(3)(ii)(C) and (i)(3)(ii), any action described by paragraphs (a)(1)(i) and (ii) of this section, by itself, does not affect the modification status of process unit equipment, centrifugal or reciprocating compressors, pumps, or process controllers.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor. A centrifugal compressor located at a well site is not an affected facility under this subpart. A centrifugal compressor located at a centralized production facility is an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site is not an affected facility under this subpart. A reciprocating compressor located at a centralized production facility is an affected facility under this subpart.

(d) Each process controller affected facility, which is the collection of natural gas-driven process controllers at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station. Natural gas-driven process controllers that function as emergency shutdown devices and process controllers that are not driven by natural gas are not included in the affected facility.

(1) For the purposes of § 60.5390b, in addition to the definition in § 60.14, a modification occurs when the number of natural gas-driven process controllers in the affected facility is increased by one or more.

(2) For the purposes of § 60.5390b, owners and operators may choose to apply reconstruction as defined in § 60.15(b) based on the fixed capital cost of the new process controllers in accordance with paragraph (d)(2)(i) of this section, or the definition of reconstruction based on the number of natural gas-driven process controllers in the affected facility in accordance with paragraph (d)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (d)(2)(i) or (ii) of this section; they do not need to apply both. If owners and operators choose to comply with paragraph (d)(2)(ii) of this section they may demonstrate compliance with § 60.15(b)(1) by showing that more than 50 percent of the number of natural gas-driven process controllers in the affected facility is replaced. That is, if an owner or operator meets the definition of reconstruction through the “number of controllers” criterion in (d)(2)(ii) of this section, they will have shown that the “fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility,” as required in § 60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of § 60.15 that reference “fixed capital cost” through an initial showing that the number of natural gas-driven process controllers replaced exceeds 50 percent. For purposes of paragraphs (d)(2)(i) and (ii), “commenced” means that an owner or operator has undertaken a continuous program of natural gas-driven process controller replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of natural gas-driven process controller replacement.

(i) If the owner or operator applies the definition of reconstruction in § 60.15(b)(1), reconstruction occurs when the fixed capital cost of the new process controllers exceeds 50 percent of the fixed capital cost that would be required to replace all the natural gas-driven process controllers in the affected facility. The “fixed capital cost of the new process controllers” includes the fixed capital cost of all natural gas-driven process controllers which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 24-month rolling period following December 6, 2022.

(ii) If the owner or operator applies the definition of reconstruction based on the percentage of natural gas-driven process controllers replaced, reconstruction occurs when greater than 50 percent of the natural gas-driven process controllers at a site are replaced. The percentage includes all natural gas-driven process controllers which are or will be replaced pursuant to all continuous programs of natural gas-driven process controller replacement which are commenced within any 24-month rolling period following December 6, 2022. If an owner or operator determines reconstruction based on the percentage of natural gas-driven process controllers that are replaced, the owner or operator must also comply with § 60.15(a).

(e) Each storage vessel affected facility, which is a tank battery that has the potential for emissions as specified in either paragraph (e)(1)(i) or (ii) of this section. A tank battery with the potential for emissions below both of the thresholds specified in paragraphs (e)(1)(i) and (ii) of this section is not a storage vessel affected facility provided the owner/operator keeps records of the potential for emissions calculation for the life of the storage vessel or until such time the tank battery becomes a storage vessel affected facility because the potential for emissions meets or exceeds either threshold specified in either paragraph (e)(1)(i) or (ii) of this section.

(1)

(i) Potential for VOC emissions equal to or greater than 6 tons per year (tpy) as determined in paragraph (e)(2) of this section.

(ii) Potential for methane emissions equal to or greater than 20 tpy as determined in paragraph (e)(2) of this section.

(2) The potential for VOC and methane emissions must be calculated as the cumulative emissions from all storage vessels within the tank battery as specified by the applicable requirements in paragraphs (e)(2)(i) through (iii) of this section. The determination may take into account requirements under a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or Tribal authority.

(i) For purposes of determining the applicability of a storage vessel tank battery as an affected facility, a legally and practicably enforceable limit must include the elements provided in paragraphs (e)(2)(i)(A) through (F) of this section.

(A) A quantitative production limit and quantitative operational limit(s) for the equipment, or quantitative operational limits for the equipment;

(B) An averaging time period for the production limit in (e)(2)(i)(A) of this section, if a production-based limit is used, that is equal to or less than 30 days;

(C) Established parametric limits for the production and/or operational limit(s) in (e)(1)(i)(A) of this section, and where a control device is used to achieve an operational limit, an initial compliance demonstration (*i.e.,* performance test) for the control device that establishes the parametric limits;

(D) Ongoing monitoring of the parametric limits in (e)(2)(i)(C) of this section that demonstrates continuous compliance with the production and/or operational limit(s) in (e)(2)(i)(A) of this section;

(E) Recordkeeping by the owner or operator that demonstrates continuous compliance with the limit(s) in (e)(2)(i)(A) through (D) of this section; and

(F) Periodic reporting that demonstrates continuous compliance.

(ii) For each tank battery located at a well site or centralized production facility, you must determine the potential for VOC and methane emissions within 30 days after startup of production, or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, except as provided in paragraph (e)(5)(iv) of this section. The potential for VOC and methane emissions must be calculated using a generally accepted model or calculation methodology that accounts for flashing, working, and breathing losses, based on the maximum average daily throughput to the tank battery determined for a 30-day period of production.

(iii) For each tank battery not located at a well site or centralized production facility, including each tank battery located at a compressor station or onshore natural gas processing plant, you must determine the potential for VOC and methane emissions prior to startup of the compressor station, onshore natural gas processing plant, or other facility within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, using either method described in paragraph (e)(2)(iii)(A) or (B) of this section.

(A) Determine the potential for VOC and methane emissions using a generally accepted model or calculation methodology that accounts for flashing, working and breathing losses and based on the throughput to the tank battery established in a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or Tribal authority; or

(B) Determine the potential for VOC and methane emissions using a generally accepted model or calculation methodology that accounts for flashing, working and breathing losses and based on projected maximum average daily throughput. Maximum average daily throughput is determined using a generally accepted engineering model (*e.g.,* volumetric condensate rates from the tank battery based on the maximum gas throughput capacity of each producing facility) to project the maximum average daily throughput for the tank battery.

(3) For the purposes of § 60.5395b, the following definitions of "reconstruction" and "modification" apply for determining when an existing tank battery becomes a storage vessel affected facility under this subpart.

(i) "Reconstruction" of a tank battery occurs when the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section and

(A) at least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel; or

(B) the provisions of § 60.15 are met for the existing tank battery.

(ii) "Modification" of a tank battery occurs when any of the actions in paragraphs (e)(3)(ii)(A) through (D) of this section occurs and the potential for VOC or methane emissions meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.

(A) A storage vessel is added to an existing tank battery;

(B) One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases;

(C) For tank batteries at well sites or centralized production facilities, an existing tank battery receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput from actions, including but not limited to, the addition of operations or a production well, or changes to operations or a production well (including hydraulic fracturing or refracturing of the well).

(D) For tank batteries not located at a well site or centralized production facility, including each tank battery at compressor stations or onshore natural gas processing plants, an existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (*i.e.,* prior to an action in paragraphs (e)(3)(ii)(A), (B) or (D) of this section) determination of the potential for VOC or methane emissions.

(4) A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart.

(5) For storage vessels not subject to a legally and practicably enforceable limit in an operating permit or other requirement established under Federal, state, local, or Tribal authority, any vapor from the storage vessel that is recovered and routed to a process through a vapor recovery unit designed and operated as specified in this section is not required to be included in the determination of potential for VOC or methane emissions for purposes of determining affected facility status, provided you comply with the requirements of paragraphs (e)(5)(i) through (iv) of this section.

(i) You meet the cover requirements specified in § 60.5411b(b).

(ii) You meet the closed vent system requirements specified in § 60.5411b(a)(2) through (4) and (c).

(iii) You must maintain records that document compliance with paragraphs (e)(5)(i) and (ii) of this section.

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs (e)(5)(i) and (ii) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(6) The requirements of this paragraph (e)(6) apply to each storage vessel affected facility immediately upon startup, startup of production, or return to service. A storage vessel affected facility or portion of a storage vessel affected facility that is reconnected to the original source of liquids remains a storage vessel affected facility subject to the same requirements that applied before being removed from service. Any storage vessel that is used to replace a storage vessel affected facility, or portion of a storage vessel affected facility, or used to expand a storage vessel affected facility assumes the affected facility status of the storage vessel affected facility being replaced or expanded.

(7) A storage vessel with a capacity greater than 100,000 gallons used to recycle water that has been passed through two stage separation is not a storage vessel affected facility.

(f) Each process unit equipment affected facility, which is the group of all equipment within a process unit at an onshore natural gas processing plant is an affected facility.

(1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by §§ 60.5400b, 60.5401b, 60.5402b, 60.5421b, and 60.5422b if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the provisions of §§ 60.5400b, 60.5401b, 60.5402b, 60.5421b, and 60.5422b.

(g) Each sweetening unit affected facility as defined by paragraphs (g)(1) and (2) of this section.

(1) Each sweetening unit that processes natural gas produced from either onshore or offshore wells is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in § 60.5423b(c) but are not required to comply with §§ 60.5405b through 60.5407b and §§ 60.5410b(i) and 60.5415b(i).

(4) Sweetening facilities producing acid gas that is completely re-injected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§ 60.5405b through 60.5407b, 60.5410b(i), 60.5415b(i), and 60.5423b.

(h) Each pump affected facility, which is the collection of natural gas-driven pumps at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station. Pumps that are not driven by natural gas are not included in the pump affected facility.

(1) For the purposes of § 60.5393b, in addition to the definition in § 60.14, a modification occurs when the number of natural gas-driven pumps in the affected facility is increased by one or more.

(2) For the purposes of § 60.5390b, owners and operators may choose to apply reconstruction as defined in § 60.15(b) based on the fixed capital cost of the new pumps in accordance with paragraph (h)(2)(i) of this section, or the definition of reconstruction based on the number of natural gas-driven pumps in the affected facility in accordance with paragraph (h)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (h)(2)(i) or (ii) of this section; they do not need to apply both. If owners and operators choose to comply with paragraph (h)(2)(ii) of this section they may demonstrate compliance with § 60.15(b)(1) by showing that more than 50 percent of the number of natural gas-driven pumps is replaced. That is, if an owner or operator meets the definition of reconstruction through the "number of pumps" criterion in (h)(2)(ii) of this section, they will have shown that the "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility," as required in § 60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of § 60.15 that reference "fixed capital cost" through an initial showing that the number of natural gas-driven pumps replaced exceeds 50 percent. For purposes of paragraphs (h)(2)(i) and (ii) of this section, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of natural gas-driven pump replacement.

(i) If the owner or operator applies the definition of reconstruction in § 60.15, reconstruction occurs when the fixed capital cost of the new pumps exceeds 50 percent of the fixed capital cost that would be required to replace all the natural gas-driven pumps in the affected facility. The "fixed capital cost of the new pumps" includes the fixed capital cost of all natural gas-driven pumps which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 24-month rolling period following December 6, 2022.

(ii) If the owner or operator applies the definition of reconstruction based on the percentage of natural gas-driven pumps replaced, reconstruction occurs when greater than 50 percent of the natural gas-driven pumps in the affected facility are replaced. The percentage includes all natural gas-driven pumps which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 24-month rolling period following December 6, 2022. If an owner or operator determines reconstruction based on the percentage of natural gas-driven pumps that are replaced, the owner or operator must comply with § 60.15(a).

(3) A natural gas-driven pump that is in operation less than 90 days per calendar year is not part of an affected facility under this subpart. For the purposes of this section, any period of operation during a calendar day counts toward the 90-calendar day threshold.

(i) Each fugitive emissions components affected facility, which is the collection of fugitive emissions components at a well site, centralized production facility, or a compressor station.

(1) For purposes of § 60.5397b and § 60.5398b, a “modification” to a well site occurs when:

(i) A new well is drilled at an existing well site;

(ii) A well at an existing well site is hydraulically fractured; or

(iii) A well at an existing well site is hydraulically refractured.

(2) For purposes of § 60.5397b and § 60.5398b, a “modification” to centralized production facility occurs when:

(i) Any of the actions in paragraphs (i)(1)(i) through (iii) of this section occurs at an existing centralized production facility;

(ii) A well sending production to an existing centralized production facility is modified, as defined in paragraphs (i)(1)(i) through (iii) of this section; or

(iii) A well site subject to the requirements of § 60.5397b or § 60.5398b removes all major production and processing equipment, such that it becomes a wellhead only well site and sends production to an existing centralized production facility.

(3) For purposes of § 60.5397b, a “modification” to a compressor station occurs when:

(i) An additional compressor is installed at a compressor station; or

(ii) One or more compressors at a compressor station is replaced by one or more compressors of greater total horsepower than the compressor(s) being replaced. When one or more compressors is replaced by one or more compressors of an equal or smaller total horsepower than the compressor(s) being replaced, installation of the replacement compressor(s) does not trigger a modification of the compressor station for purposes of § 60.5397b.

§ 60.5370b When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than May 7, 2024 or upon initial startup, whichever date is later, except as specified in paragraph (a)(1) of this section for reciprocating compressor affected facilities, paragraphs (a)(2) and (3) of this section for storage vessel affected facilities, paragraph (a)(4) of this section for process unit equipment affected facilities at onshore natural gas processing plants, paragraph (a)(5) of this section for process controllers, paragraph (a)(6) of this section for pumps, paragraph (a)(7) of this section for centrifugal compressor affected facilities, and paragraphs § 60.5377b(b) or (c) for associated gas wells.

(1) You must comply with the requirements of § 60.5385b(a) for your reciprocating compressor affected facility as specified in paragraph (a)(1)(i), (ii), or (iii) of this section, as applicable.

(i) You must comply with the requirements of § 60.5385b(a)(1) and (d)(3) on or before 8,760 hours of operation after May 7, 2024, on or before 8,760 hours of operation after last rod packing replacement, or on or before 8,760 hours of operation after startup, whichever date is later; and

(ii) You must comply with the requirements of § 60.5385b(a)(2) within 8,760 hours after compliance with § 60.5385b(a)(1) and (d)(3).

(iii) You must comply with the requirements of § 60.5385b(d)(1) and (2) for your reciprocating compressor upon initial startup.

(2) You must comply with the requirements of paragraphs § 60.5395b(a)(1) for your storage vessel affected facility as specified in paragraphs (a)(2)(i) or (ii) of this section, as applicable.

(i) Within 30 days after startup of production, or within 30 days after reconstruction or modification of the storage vessel affected facility, for each storage vessel affected facility located at a well site or centralized production facility.

(ii) Prior to startup of the compressor station or onshore natural gas processing plant, or within 30 days after reconstruction or modification of the storage vessel affected facility, for each storage vessel affected facility located at a compressor station or onshore natural gas processing plant.

(3) You must comply with the requirements of paragraph § 60.5395b(a)(2) as specified in paragraph (a)(3)(i) or (ii) of this section, as applicable:

(i) For each storage vessel affected facility located at a well site or centralized production facility, you must achieve the required emissions reductions within 30 days after the determination in paragraph (a)(2)(i) of this section.

(ii) For storage vessel affected facilities located at a compressor station or onshore natural gas processing plant, you must achieve the required emissions reductions within 30 days after the determination in paragraph (a)(2)(ii) of this section.

(4) You must comply with the requirements of § 60.5400b for all process unit equipment affected facilities at a natural gas processing plant, as soon as practicable but no later than 180 days after the initial startup of the process unit.

(5) For process controller affected facilities, you must comply with the requirements of paragraph (a)(5)(i) or (ii) of this section, as applicable.

(i) Any process controller affected facilities may comply with § 60.5390b(b)(1) and (2) or (3) as an alternative to compliance with § 60.5390b(a) until [May 7, 2025.

(ii) On or after May 7, 2025, process controller affected facilities must comply with § 60.5390b(a) or (b), as specified in those paragraphs.

(6) For pump affected facilities, you must comply with the requirements of paragraph (a)(6)(i) or (ii) of this section, as applicable.

(i) Any pump affected facility may comply with § 60.5393b(b)(2) through (8), as applicable, as an alternative to compliance with § 60.5393b(a) until May 7, 2025.

(ii) On or after May 7, 2025, pump affected facilities must comply with § 60.5393b(a) or (b), as specified in those paragraphs.

(7) For centrifugal compressor affected facilities, you must comply with the requirements of paragraph (a)(7)(i) or (ii) of this section, as applicable.

(i) You must comply with the requirements of § 60.5380b(a)(1) and (2), or (a)(3) for your reciprocating compressor upon initial startup.

(ii) Each centrifugal compressor affected facility that uses dry seals, each self-contained wet seal compressor, and each centrifugal compressor on the Alaska North Slope equipped with sour seal oil separator and capture system, complying with one of the alternatives in § 60.5380b(a)(4), (5), or (6), must comply with the specified performance-based volumetric flow rate work practice standards on or before 8,760 hours of operation after May 7, 2024, on or before 8,760 hours of operation after last seal replacement, or on or before 8,760 hours of operation after startup, whichever date is later.

(b) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating 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, opacity observations, review of operating and maintenance procedures, and inspection of the source. The provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

§ 60.5371b What GHG and VOC standards apply to super-emitter events?

This section applies to super-emitter events. For purposes of this section, a super-emitter event is defined as any emissions event that is located at or near an oil and natural gas facility (*e.g.,* individual well site, centralized production facility, natural gas processing plant, or compressor station) and that is detected using remote detection methods and has quantified emission rate of 100 kg/hr of methane or greater. Paragraph (a) of this section describes the qualifications one must meet to apply to be a third-party notifier of super-emitter events. Paragraph (b) of this section describes the procedures for certifying third-party notifiers, as well as the procedures for petitioning the Agency for removal of a third-party notifier from the list of certified notifiers. Paragraph (c) of this section contains the required information that must be included in any notification submitted to the EPA from a certified third-party notifier and a timetable for notifications. The EPA shall review these notifications and if the EPA determines the notification is complete and does not contain information that the EPA finds to be erroneous or inaccurate to a reasonable degree of certainty, the EPA shall assign the notification a unique notification identification number, provide the notification to the owner or operator of the oil and natural gas facility identified in the notification, and post the notification, except for the owner/operator attribution, at *www.epa.gov/super-emitter.* Upon receiving such notification, owners or operators must take the actions listed in paragraphs (d) and (e) of this section. The EPA shall post the reports submitted under paragraph (e) of this section, § 60.5371(b) and § 60.5371a(b) of subparts OOOO and OOOOa of this part, and applicable State or Federal plan implementing § 60.5388c(b) of subpart OOOOc of this part, including owner/operator attributions that have been confirmed by the reports; where the reporting deadlines have passed but no reports have been received, the EPA intends to post owner/operator attributions that the EPA reasonably believes to be accurate. The reports will be publicly available at *www.epa.gov/super-emitter*.

(a) ***Qualifications for third-party notifiers.*** An entity may apply to the Administrator under paragraph (b) of this section for approval as a third-party notifier if it meets the qualifications in this paragraph (a). The entity must be a person, as defined in 42 U.S.C. 7602(e), excluding the owner or operator of the site where the super-emitter event is detected, the Administrator, or the delegated authority. The entity must use a method that has been approved under § 60.5398b(d) for one of the technologies specified in paragraphs (a)(1) through (3) of this section.

(1) Satellite detection of methane emissions.

(2) Remote-sensing equipment on aircraft.

(3) Mobile monitoring platforms.

(b) ***Third-party notifier certification.*** An entity meeting the qualifications in paragraph (a) of this section may apply to be certified as a third-party notifier. Only entities certified as third-party notifiers may submit information on super-emitter events to the EPA under paragraph (c) of this section. An entity seeking certification as a third-party notifier must submit a request to the Administrator as described in paragraph (b)(1) of this section. Certified third-party notifiers must follow the recordkeeping requirements in paragraph (b)(2) of this section; failure to maintain the required records may result in loss of certification status. The Administrator will determine whether the request for certification is adequate and issue an approval or disapproval of the request as described in paragraph (b)(3) of this section. A certified third-party notifier must re-apply when material changes are made, as described in paragraph (b)(4) of this section. A third-party notifier may be removed from the list of certified notifiers as detailed in paragraph (b)(5) of this section.

(1) A request to be certified as a third-party notifier must be submitted to: U.S. EPA, Attn: Leader, Measurement Technology Group, Mail Drop: E143-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. The request must include the supporting information in paragraphs (b)(1)(i) through (vi) of this section. If your submittal includes information claimed to be CBI, submit the portion of the information claimed as CBI to the OAQPS CBI office. 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 should include clear CBI markings and be flagged to the attention of the Leader, Measurement Technology 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. 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 Technology Group Leader, 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.

(i) General identification information for the candidate third-party notifier requesting certification as a third-party notifier including the mailing address, the physical address, the name of a principal officer and an email address for the principal officer, and name of the certifying official(s) and the certifying official(s)'s email address.

(ii) Description of the technologies the entity will use to identify emissions that are 100 kg/hr of methane or greater. At a minimum, the description must include the following:

(A) Reference to the approval of the method to be used under § 60.5398b(d).

(B) Memorandum of Understanding (MOU) or contracting agreements with the technology provider(s) that will be used to identify super-emitter events (if applicable).

(iii) Curriculum vitae of the certifying official(s) detailing their work history, education, skill set, and training for evaluating the results of the technologies that will be used to identify super-emitter events.

(iv) The candidate third-party notifier's standard operating procedure(s) detailing the procedures and processes for data review. At a minimum, this must include the following:

(A) Procedures for evaluating the emission data provided by the technology, including the accuracy of the data and whether the data was collected in compliance with the method requirements approved under § 60.5398b(d).

(B) Process for verifying the accuracy of the locality of emissions.

(C) Process for identifying and verifying the owner or operator of a site where a super-emitter event occurs, including the source of information that will be used to make the identification.

(D) Procedures for handling potentially erroneous data.

(v) Description of the systems used for maintaining essential records identified in paragraph (b)(2) of this section.

(vi) A Quality Management Plan consistent with EPA's Quality Management Plan Standard (Directive No: CIO 2015-S-01.0, January 17, 2023) for Non-EPA organizations.

(2) Certified third-party notifiers must maintain the records identified in paragraphs (b)(2)(i) through (iii) of this section. Upon request, the certified third-party notifier must make these records available to the Administrator for review.

(i) Records for all surveys conducted by or sponsored by the certified third-party notifier, including outputs (*e.g.,* emission rates, locations) and associated data needed to confirm the accuracy of the outputs and the performance of the method used.

(ii) Records of all notifications of super-emitter events provided to the EPA. Retain any information collected that is used to evaluate the validity of a super-emitter event but which is not required to be submitted as part of the notification.

(iii) A copy of any records and/or identification of any databases used in the identification of the potential owner or operator of the site where a super-emitter event occurred.

(3) Based upon the Administrator's judgment of the completeness, reasonableness, and accuracy of the entity's request, the Administrator will approve or disapprove the entity for certification as a third-party notifier. For those third parties that receive approval, the Administrator will provide you a unique notifier ID. Starting 15 calendar days after being approved as a certified third-party notifier, the notifier may submit notifications of super-emitter events to the EPA as outlined in paragraph (c) of this section. All approved third-party notifiers shall be posted on the EPA website at *www.epa.gov/emc-third-party-certifications*.

(4) If a third-party notifier intends to make any significant changes to their procedures for identifying super-emitter events, meaning a change to the technology used to identify super-emitter events or a change to the certifying official(s), you must request an amendment to your certification and be recertified under paragraph (b)(1) of this section.

(5) A certified third-party notifier may be removed from the list of approved third-party notifiers in any of the circumstances listed in paragraphs (b)(5)(i) through (iii) of this section. Entities removed from the list of approved third-party notifiers cannot submit notifications to the EPA under paragraph (c) of this section. Entities may be added back to the list of approved third-party notifiers by receiving approval of a new certification request submitted under paragraph (b)(1) of this section.

(i) If a certified third-party notifier has made material changes to their procedures for identifying super-emitter events, meaning a change to the technology used to identify super-emitter events or a change to the certifying official, without seeking recertification.

(ii) If the Administrator finds that the certified third-party notifier has persistently submitted data with significant errors (*e.g.,* misidentification of the owner or operator) or if the third-party notifier has engaged in illegal activity during the during the assessment of a super-emitter event (*e.g.,* trespassing).

(iii) If the Administrator receives a petition from an owner or operator to remove a certified third-party notifier from the list of approved notifiers, as set forth below, and the Administrator makes the finding noted below. Any owner or operator that has received more than three notices with meaningful and/or demonstrable errors of a super-emitter event at the same oil and natural gas facility (*e.g.,* a well site, centralized production facility, natural gas processing plant, or compressor station) from the EPA that were submitted to the EPA by the same third party may petition the Administrator to remove that third party from the list of approved notifiers, by providing evidence that the claimed super-emitter events did not occur. Such petitions may not be used to dispute the methodology that were approved through the process described in § 60.5398b(d). The third party will be given the opportunity to respond to the petition. If, in the Administrator's discretion, the Administrator determines that the three notifications contain meaningful and/or demonstrable errors, including that the third party did not use the methane detection technology identified in their submittal, the emissions event did not exceed the threshold of 100 kg/hr of methane, the third-party knowingly misidentified the date of a super-emitter event, the third party may be removed by the Administrator from the list of approved notifiers. The failure of the owner or operator to find the source of the super-emitter event upon subsequent inspection shall not be proof, by itself, of demonstrable error.

(c) ***Notification of super-emitter events.*** Notifications must be submitted to the EPA using the Super-Emitter Program Portal (available at *http://www.epa.gov/super-emitter*). Notifications must contain the information specified in paragraphs (c)(1) through (8) of this section. The EPA will review the submitted notifications of super-emitter events for completeness and accuracy. If the EPA determines that the notification is complete and does not contain information that the EPA finds to be inaccurate to a reasonable degree of certainty, the EPA will assign the notification a unique notification report identification number, make the notification publicly available at *www.epa.gov/super-emitter,* and provide the super-emitter event notification to the owner or operator identified in the notification. The EPA will not review and provide the notification to an owner or operator if the notification is submitted after the date specified in paragraph (c)(9) of this section.

(1) Unique Third-Party Notifier ID.

(2) Date of detection of the super-emitter event. If multiple surveys were required to detect and quantify the super-emitter event, the date of detection is the date of the final survey.

(3) Location of super-emitter event in latitude and longitude coordinates in decimal degrees to an accuracy and precision of four (4) decimals of a degree using the North American Datum of 1983.

(4) Owner(s) or operator(s) of any oil and natural gas facility (*e.g.,* individual well site, centralized production facility, natural gas processing plant, or compressor station) within 50 meters of the latitude and longitude coordinates of the super-emitter event.

(5) Identification of the detection technology and reference to the approval of the technology used under § 60.5398b(d).

(6) Documentation (*e.g.,* imagery) depicting the detected super-emitter event and the site from which the super-emitter event was detected.

(7) Quantified emission rate of the super-emitter event in kg/hr and associated uncertainty bounds (*e.g.,* 1-σ) of the measurement.

(8) Attestation statement, signed and dated by the third-party notifier certifying official submitting the data collected. The attestation must state: “I certify that I have been approved to be a notifier under 40 CFR 60.5371b(b) and that the emission detection information included in this notification was collected and interpreted as described in this notification. Based on my professional knowledge and experience, and inquiry of personnel involved in the collection and analysis of the data, the certification submitted herein is true, accurate, and complete.”

(9) The third-party notifier must submit the notification within 15 calendar days of the date of detection of the super-emitter event.

(d) ***Identification of super-emitter events.*** Within 5 calendar days of receiving a notification from the EPA of a super-emitter event, the owner or operator of an oil and natural gas facility (*e.g.,* a well site, centralized production facility, natural gas processing plant, or compressor station) must initiate a super-emitter event investigation. The investigation must be conducted in accordance with this paragraph (d) and completed within 15 days of receiving the notification from the EPA. The owner or operator must maintain records of its super-emitter event investigations and report the findings from the investigation according to the requirements in paragraph (e) of this section.

(1) If you do not own or operate an oil and natural gas facility within 50 meters from the latitude and longitude provided in the notification, report this result to the EPA under paragraph (e) of this section. Your super-emitter event investigation is deemed complete.

(2) If you own or operate an oil and natural gas facility within 50 meters from the latitude and longitude provided in the notification, you must investigate to determine the source of super-emitter event. The investigation may include but is not limited to the actions specified below in paragraphs (d)(6)(i) through (v) of this section.

(i) Review any maintenance activities (*e.g.,* liquids unloading) or process activities from the affected facilities subject to regulation under this subpart, starting from the date of detection of the super-emitter event as identified in the notification, until the date of investigation, to determine if the activities indicate any potential source(s) of the super-emitter event emissions.

(ii) Review all monitoring data from control devices (*e.g.,* flares) from the affected facilities subject to regulation under this subpart from the initial date of detection of the super-emitter event as identified in the notification until the date of receiving the notification from the EPA. Identify any malfunctions of control devices or periods when the control devices were not in compliance with applicable requirements and that indicate a potential source of the super-emitter event emissions.

(iii) If you conducted a fugitive emissions survey or periodic screening event in accordance with § 60.5397b or § 60.5398b(b) between the initial date of detection of the super-emitter event as identified in the notification and the date the notification from the EPA was received, review the results of the survey to identify any potential source(s) of the super-emitter event emissions.

(iv) If you conduct continuous monitoring with advanced methane detection technology in accordance with § 60.5398b(c), review the monitoring data collected on or after the initial date of detection of the super-emitter event as identified in the notification, until the date of receiving the notification from the EPA.

(v) Screen the entire oil and natural gas facility with OGI, Method 21 of appendix A-7 to this part, or an alternative test method(s) approved per § 60.5398b(d), to determine if a super-emitter event is present.

(3) If the source of the super-emitter event was found to be from fugitive emission components at a well site, centralized production facility, or compressor station subject to this subpart, you must comply with the repair requirements under § 60.5397b and the associated recordkeeping and reporting requirements under § 60.5420b(b)(9) and (c)(14).

(e) ***Super-emitter event report.*** You must submit the results of the super-emitter event investigation conducted under paragraph (d) of this section to the EPA in accordance with paragraph (e)(1) of this section. If the super-emitter event (*i.e.,* emission at 100 kg/hr of methane or more) is ongoing at the time of the initial report, submit the additional information in accordance with paragraph (e)(2) of this section. You must attest to the information included in the report as specified in paragraph (e)(3) of this section.

(1) Within 15 days of receiving a notification from the EPA under paragraph (c) of this section, you must submit a report of the super-emitter event investigation conducted under paragraph (d) of this section through the Super-Emitter Program Portal. You must include the applicable information in paragraphs (e)(1)(i) through (viii) of this section in the report. If you have identified a demonstrable error in the notification, the report may include a statement of the demonstrable error.

(i) Notification Report ID of the super-emitter event notification.

(ii) Identification of whether you are the owner or operator of an oil and natural gas facility within 50 meters from the latitude and longitude provided in the EPA notification. If you do not own or operate an oil and natural gas facility within 50 meters from the latitude and longitude provided in the EPA notification, you are not required to report the information in paragraphs (e)(1)(iii) through (viii) of this section.

(iii) General identification information for the facility, including, facility name, the physical address, applicable ID Number (*e.g.,* EPA ID Number, API Well ID Number), the owner or operator or responsible official (where applicable) and their email address.

(iv) Identification of whether there is an affected facility or associated equipment subject to regulation under this subpart at this oil and natural gas facility.

(v) Indication of whether you were able to identify the source of the super-emitter event. If you indicate you were unable to identify the source of the super-emitter event, you must certify that all applicable investigations specified in paragraph (d)(6)(i) through(v) of this section have been conducted for all affected facilities and associated equipment subject to this subpart that are at this oil and natural gas facility, and you have determined that the affected facilities and associated equipment are not the source of the super-emitter event. If you indicate that you were not able to identify the source of the super-emitter event, you are not required to report the information in paragraphs (e)(1)(vi) through (viii) of this section.

(vi) The source(s) of the super-emitter event.

(vii) Identification of whether the source of the super-emitter event is equipment subject to regulation under this subpart. If the source of the super-emitter event is equipment subject to regulation under this subpart, identify the applicable regulation(s) under this subpart.

(viii) Indication of whether the super-emitter event is ongoing at the time of the initial report submittal (*i.e.,* emissions at 100 kg/hr of methane or more).

(A) If the super-emitter event is not ongoing at the time of the initial report submittal, provide the actual (or if unknown) estimated date and time the super-emitter event ended.

(B) If the super-emitter event is ongoing at the time of the initial report submittal, provide a short narrative of your plan to end the super-emitter event, including the targeted end date for the efforts to be completed and the super-emitter event ended.

(2) If the super-emitter event is ongoing at the time of the initial report submittal, within 5 business days of the date the super-emitter event ends, you must update your initial report through the Super-Emitter Program Portal to provide the end date and time of the super-emitter event.

(3) You must sign the following attestation when submitting data into the Super-Emitter Program Portal: "I certify that the information provided in this report regarding the specified super-emitter event was prepared under my direction or supervision. I further certify that the investigations were conducted, and this report was prepared pursuant to the requirements of § 60.5371b(d) and (e). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that knowingly false statements may be punishable by fine or imprisonment."

§ 60.5375b What GHG and VOC standards apply to well completions at well affected facilities?

(a) You must comply with the requirements of paragraphs (a)(1) through (3) of this section for each well completion operation with hydraulic fracturing and refracturing at a well affected facility, except as provided in paragraphs (f), (g) and (h) of this section. You must maintain a log as specified in paragraph (b) of this section.

(1) For each stage of the well completion operation, follow the requirements specified in paragraphs (a)(1)(i) through (iii) of this section.

(i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. The separator may be a production separator, but the production separator also must be designed to accommodate flowback. Any gas present in the initial flowback stage is not subject to control under this section.

(ii) During the separation flowback stage, route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the recovered liquids into the well or another well, or route the recovered liquids to a collection system. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an onsite fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is technically infeasible to route the recovered gas as required above, follow the requirements of paragraph (a)(2) of this section. If, at any time during the separation flowback stage, it is technically infeasible for a separator to function, you must comply with paragraph (a)(1)(i) of this section.

(iii) You must have the separator onsite or otherwise available for use at a centralized production facility or well pad that services the well completion affected facility during well completions. The separator must be available and ready for use to comply with paragraph (a)(1)(ii) of this section during the entirety of the flowback period, except as provided in paragraphs (a)(1)(iii)(A) through (C) of this section.

(A) A well that is not hydraulically fractured or refractured with liquids, or that does not generate condensate, intermediate hydrocarbon liquids, or produced water such that there is no liquid collection system at the well site is not required to have a separator onsite.

(B) If conditions allow for liquid collection, then the operator must immediately stop the well completion operation, install a separator, and restart the well completion operation in accordance with paragraph (a)(1) of this section.

(C) The owner or operator of a well that meets the criteria of paragraph (a)(1)(iii)(A) or (B) of this section must submit the report in § 60.5420b(b)(2) and maintain the records in § 60.5420b(c)(1)(iii).

(2) If it is technically infeasible to route the recovered gas as required in § 60.5375b(a)(1)(ii), then you must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(3) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

(b) You must maintain a log for each well completion operation at each well affected facility. The log must be completed on a daily basis for the duration of the well completion operation and must contain the records specified in § 60.5420b(c)(1)(iii).

(c) You must demonstrate initial compliance with the well completion operation standards that apply to well affected facilities as required by § 60.5410b(a).

(d) You must demonstrate continuous compliance with the well completion operation standards that apply to well affected facilities as required by § 60.5415b(a).

(e) You must perform the required notification, reporting and recordkeeping as required by § 60.5420b(a)(2), (b)(1) and (2), and (c)(1).

(f) For each well affected facility specified in paragraphs (f)(1) and (2) of this section, you must comply with the requirements of paragraphs (f)(3) and (4) of this section.

(1) Each well completion operation with hydraulic fracturing at a wildcat or delineation well.

(2) Each well completion operation with hydraulic fracturing at a non-wildcat low pressure well or non-delineation low pressure well.

(3) You must comply with paragraph (f)(3)(i) of this section. You must also comply with paragraph (b) of this section. As an alternative, if you are able to operate a separator, you may comply with paragraph (b) and (f)(3)(ii) of this section. Compliance with paragraphs (f)(3)(i) or (ii) of this section is not required if you meet the requirements of paragraph (g) of this section.

(i) Route all flowback to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(ii) Route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. You must have the separator onsite or otherwise available for use at the wildcat well, delineation well, or low pressure well. The separator must be available and ready for use to comply with paragraph (f)(3)(ii) of this section during the entirety of the flowback period. Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(4) You must submit the notification as specified in § 60.5420b(a)(2), submit annual reports as specified in § 60.5420b(b)(1) and (2) and maintain records specified in § 60.5420b(c)(1)(i) through (iii) and (vii) for each wildcat well, each delineation well, and each low pressure well.

(g) For each well completion affected facility with less than 300 scf of gas per stock tank barrel of oil produced, you must comply with paragraphs (g)(1) and (2) of this section.

(1) You must maintain records specified in § 60.5420b(c)(1)(vi).

(2) You must submit reports specified in § 60.5420b(b)(1) and (2).

(h) A well modified in accordance with § 60.5365b(a)(1)(ii) (*i.e.,* an existing well that is hydraulically refractured) is exempt from the well completion operation standards in paragraphs (b) through (d) of this section, when the requirements of paragraphs (a)(1) through (3) of this section are met.

§ 60.5376b What GHG and VOC standards apply to gas well liquids unloading operations at well affected facilities?

(a) ***General requirements.*** You must comply with the requirements of this section for each gas well liquids unloading operation at your gas well affected facility as specified by paragraphs (a)(1) and (2) of this section. You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during gas well liquids unloading operations.

(1) If a gas well liquids unloading operation technology or technique employed does not result in venting of methane and VOC emissions to the atmosphere, you must comply with the requirements specified in paragraphs (a)(1)(A) and (B). If an unplanned venting event occurs, you must meet the requirements specified in paragraphs (c) through (f) of this section.

(A) Comply with the recordkeeping requirements specified in § 60.5420b(c)(2)(i).

(B) Submit the information specified in § 60.5420b(b)(1) and (b)(3)(i) in the annual report.

(2) If a gas well liquids unloading operation technology or technique vents methane and VOC emissions to the atmosphere, you must comply with the requirements specified in paragraphs (b) and (c), or paragraph (g) of this section.

(b) ***Work Practice Standards.*** If a gas well liquids unloading operation employs a technology or technique that vents methane and VOC emissions to the atmosphere, you must comply with the requirements in paragraphs (b)(1) through (3) and paragraphs (c) through (f) of this section.

(1) Employ best management practices to minimize venting of methane and VOC emissions as specified in paragraph (c) of this section for each gas well liquids unloading operation.

(2) Comply with the recordkeeping requirements specified in § 60.5420b(c)(2)(ii).

(3) Submit the information specified in § 60.5420b(b)(1) and (b)(3)(ii) in the annual report.

(c) ***Best management practice requirements.*** For each gas well liquids unloading operation complying with paragraphs (a)(2) and (b) of this section, you must develop, maintain, and follow a best management practice plan to minimize venting of methane and VOC emissions to the maximum extent possible from each gas well liquids unloading operation. This best management practice plan must meet the minimum criteria specified in paragraphs (c)(1) through (4) of this section.

(1) Include steps that create a differential pressure to minimize the need to vent a well to unload liquids,

(2) Include steps to reduce wellbore pressure as much as possible prior to opening the well to the atmosphere,

(3) Unload liquids through the separator where feasible, and

(4) Close all wellhead vents to the atmosphere and return the well to production as soon as practicable.

(d) ***Initial compliance.*** You must demonstrate initial compliance with the standards that apply to well liquids unloading operations at your well affected facilities as required by § 60.5410b(b).

(e) ***Continuous compliance.*** You must demonstrate continuous compliance with the standards that apply to well liquids unloading operations at your well affected facilities as required by § 60.5415b(b).

(f) ***Recordkeeping and reporting.*** You must perform the required notification, recordkeeping and reporting requirements as specified in § 60.5420b(b)(3) and (c)(2).

(g) ***Other compliance options.*** Reduce methane and VOC emissions from well affected facility gas wells that unload liquids by 95.0 percent by complying with the requirements specified in paragraphs (g)(1) and (2) of this section and meeting the initial and continuous compliance and recordkeeping and reporting requirements specified in paragraphs (g)(3) through (5) of this section.

(1) You must route emissions through a closed vent system to a control device that meets the conditions specified in § 60.5412b.

(2) You must route emissions through a closed vent system that meets the requirements of § 60.5411b(a) and (c).

(3) You must demonstrate initial compliance with standards that apply to well affected facility gas well liquids unloading as required by § 60.5410b(b).

(4) You must demonstrate continuous compliance with standards that apply to well affected facility gas well liquids unloading as required by § 60.5415b(f).

(5) You must perform the reporting as required by § 60.5420b(b)(1), (3), and (11) through (13), as applicable, and the recordkeeping as required by § 60.5420b(c)(2), (8), and (10) through (13), as applicable.

§ 60.5377b What GHG and VOC standards apply to associated gas wells at well affected facilities?

(a) You must comply with either paragraph (a)(1), (2), (3), or (4) of this section for each associated gas well upon startup and at all times, except as provided in paragraphs (b) through (f) of this section. You must also comply with paragraphs (h), (i), and (j) of this section.

(1) Recover the associated gas from the separator and route the recovered gas into a gas gathering flow line or collection system to a sales line.

(2) Recover the associated gas from the separator and use the recovered gas as an onsite fuel source.

(3) Recover the associated gas from the separator and use the recovered gas for another useful purpose that a purchased fuel or raw material would serve.

(4) Recover the associated gas from the separator and reinject the recovered gas into the well or inject the recovered gas into another well.

(b) For associated gas wells that commenced construction between May 7, 2024 and May 7, 2026, you can comply with the requirements in paragraph (f) of this section continually upon startup instead of paragraph (a) of this section until May 7, 2026 if you demonstrate and certify that it is not feasible to comply with paragraphs (a)(1), (2), (3), and (4) of this section due to technical reasons in accordance with paragraph (g) of this section. After May 7, 2026 you must continually comply with paragraph (a) of this section at all times.

(c) For associated gas wells that commenced construction between December 6, 2022, and May 7, 2024, and for associated gas wells that undergo reconstruction or modification after December 6, 2022, you can comply with the requirements in paragraph (f) of this section instead of paragraph (a) of this section if you demonstrate and certify that it is not feasible to comply with paragraph (a)(1), (2), (3), and (4) of this section due to technical reasons in accordance with paragraph (g) of this section. Associated gas wells that are modified or reconstructed must comply with paragraph (a) or (f) of this section upon startup and at all times thereafter.

(d) If you are complying with paragraph (a) of this section, you may temporarily route the associated gas to a flare or control device that achieves a 95.0 percent reduction in VOC and methane emissions in the situations and for the durations identified in paragraphs (d)(1), (2), (3), or (4) of this section. The associated gas must be routed through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and the control device must meet the conditions specified in § 60.5412b during the period when the associated gas is routed to the flare. Records must be kept of all instances in which associated gas is temporarily routed to a flare or to a control device in accordance with § 60.5420b(c)(3)(i)(B) and reported in the annual report in accordance with § 60.5420b(b)(4)(i)(B).

(1) During a malfunction or incident that endangers the safety of operator personnel or the public you are allowed to route to a flare or control device for 24 hours or less per incident.

(2) During repair, maintenance including blow downs, a production test, or commissioning, you are allowed to route to a flare or control device for 24 hours or less per incident.

(3) For wells complying with paragraph (a)(1) of this section, during a temporary interruption in service from the gathering or pipeline system you are allowed to route to a flare or route to a control device for the duration of the temporary interruption not to exceed 30 days per incident.

(4) During periods when the composition of the associated gas does not meet pipeline specifications for sources complying with paragraph (a)(1) of this section, or when the composition of the associated gas does not meet the quality requirements for use as a fuel for sources complying with paragraph (a)(2) of this section, or when the composition of the associated gas does not meet the quality requirements for another useful purpose for sources complying with paragraph (a)(3) of this section, you are allowed to route to a flare or control device until the associated gas meets the required specifications or for 72 hours per incident, whichever is less.

(e) If you are complying with paragraph (a), (d), or (f) of this section, you may vent the associated gas in the situations and for the durations identified in paragraphs (e)(1), (2), or (3) of this section per incident. The cumulative period of venting must not exceed 24 hours for any calendar year. Records must be kept of all venting instances in accordance with § 60.5420b(c)(3)(ii) and reported in the annual report in accordance with § 60.5420b(b)(4)(ii).

(1) For up to 12 hours per incident to protect the safety of personnel.

(2) For up to 30 minutes per incident during bradenhead monitoring.

(3) For up to 30 minutes per incident during a packer leakage test.

(f) You must route the associated gas to a control device that reduces methane and VOC emissions by at least 95.0 percent. The associated gas must be routed through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and the control device must meet the conditions specified in § 60.5412b.

(1) For associated gas wells identified in paragraph (b) of this section, you can comply with the requirements in paragraph (f) of this section for up to a one year period if you demonstrate and certify that it is not feasible to comply with paragraph (a)(1), (2), (3), and (4) of this section due to technical reasons in accordance with paragraph (g) of this section. This allowance is renewable each year with an updated technical infeasibility demonstration and certification in accordance with paragraph (g) of this section. Associated gas wells identified in paragraph (b) of this section are not allowed to comply with the requirements in paragraph (f) of this section after May 7, 2026.

(2) For associated gas wells identified in paragraph (c) of this section, you can comply with the requirements in paragraph (f) of this section for up to a one year period if you demonstrate and certify that it is not feasible to comply with paragraph (a)(1), (2), (3), and (4) of this section due to technical reasons in accordance with paragraph (g) of this section. This allowance is renewable each year with an updated technical infeasibility demonstration and certification in accordance with paragraph (g) of this section.

(g) For affected sources identified in paragraphs (b) and (c) of this section that are complying with the requirements in paragraph (f) of this section, you must demonstrate that it is not feasible to comply with paragraph (a)(1), (2), (3), and (4) of this section due to technical reasons by providing a detailed analysis documenting and certifying the technical reasons for this infeasibility.

(1) The demonstration must address the technical infeasibility for all options identified in (a)(1), (2), (3), and (4) of this section.

(2) This demonstration must be certified by a professional engineer or another qualified individual with expertise in the uses of associated gas. The following certification, signed and dated by the qualified professional engineer or other qualified individual shall state: “I certify that the assessment of technical and safety infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted, and this report was prepared pursuant to the requirements of § 60.5377b(b)(1). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.”

(3) This demonstration and certification are valid for no more than 12 months. You must re-analyze the feasibility of complying with paragraphs (a)(1), (2), (3), and (4) of this section and finalize a new demonstration and certification each year.

(4) Documentation of these demonstrations, along with the certifications, must be maintained in accordance with § 60.5420b(c)(3)(iii) and submitted in annual reports in accordance with § 60.5420b(b)(4)(iii)(C) and (D).

(h) You must demonstrate initial compliance with the standards that apply to associated gas wells as required by § 60.5410b(c).

(i) You must demonstrate continuous compliance with the standards that apply to associated gas wells as required by § 60.5415b(c).

(j) You must perform the reporting as required by § 60.5420b(b)(1) and (4), and (b)(11) and (12), as applicable; and the recordkeeping as required by § 60.5420b(c)(3) and (8), and (c)(10) through (13), as applicable.

§ 60.5380b What GHG and VOC standards apply to centrifugal compressor affected facilities?

Each centrifugal compressor affected facility must comply with the GHG and VOC standards in paragraphs (a) through (d) of this section.

(a) Each centrifugal compressor affected facility that uses wet seals must comply with the GHG and VOC standards in paragraphs (a)(1), (2), or (3) of this section. Each self-contained wet seal compressor, and each centrifugal compressor on the Alaska North Slope equipped with sour seal oil separator and capture system, must comply with the GHG and VOC standards in paragraphs (a)(1) and (2) of this section, or one of the alternatives in (a)(3) through (5) of this section, as applicable, and (a)(8) of this section. Each centrifugal compressor affected facility that uses dry seals must comply with paragraphs (a)(6) through (8) of this section, or with of the alternatives in paragraph (a)(9) of this section.

(1) You must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and the closed vent system must be routed to a control device that meets the conditions specified in § 60.5412b.

(3) As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process. If you route the emissions to a process, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of § 60.5411b(a) and (c).

(4) If you own or operate a self-contained wet seal centrifugal compressor you may comply with the GHG and VOC requirements as specified in paragraph (a)(4)(i) through (iii) of this section, using volumetric flow rate as a surrogate, in lieu of meeting the requirements specified in paragraphs (a)(1) and (2) of this section. You must determine the volumetric flow rate in accordance with paragraph (a)(7)(i) of this section.

(i) The volumetric flow rate must not exceed 3 standard cubic feet per minute (scfm) per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 3 scfm. If the volumetric flow rate, measured in accordance with paragraph (a)(7)(i) of this section exceeds 3 scfm multiplied by the number of wet seals connected to the vent, the seals connected to the measured vent must be repaired as provided in paragraph (a)(8) of this section.

(ii) You must conduct your first volumetric flow rate measurement from your self-contained wet seal compressor on or before 8,760 hours of operation after May 7, 2024 or on or before 8,760 hours of operation after startup, whichever date is later.

(iii) You must conduct subsequent volumetric flow rate measurements from your self-contained wet seal centrifugal compressor on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with the 3 scfm volumetric flow rate per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 3 scfm.

(5) If you own or operate a centrifugal compressor on the Alaska North Slope equipped with seal oil separator and capture system, you may comply with the GHG and VOC requirements specified in paragraphs (a)(5)(i) through (iii) of this section using volumetric flow rate as a surrogate, in lieu of meeting the requirements specified in paragraphs (a)(1) and (2). You must determine the volumetric flow rate in accordance with paragraph (a)(7)(ii) of this section.

(i) The volumetric flow rate per seal must not exceed 9 scfm per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 9 scfm. If the volumetric flow rate, measured in accordance with paragraph (a)(7)(ii) of this section exceeds 9 scfm multiplied by the number of wet seals connected to the vent, the seals connected to the measured vent must be repaired as provided in paragraph (a)(8) of this section.

(ii) You must conduct your first volumetric flow rate measurement from your Alaska North Slope centrifugal compressor equipped with a sour seal oil separator and capture system on or before 8,760 hours of operation after May 7, 2024 or on or before 8,760 hours of operation after startup, whichever date is later.

(iii) You must conduct subsequent volumetric flow rate measurements from your Alaska North Slope centrifugal compressor equipped with sour seal separator and capture system on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with the 9 scfm volumetric flow rate per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 9 scfm.

(6) If you own or operate a centrifugal compressor equipped with dry seals, you must comply with the GHG and VOC requirements as specified in paragraphs (a)(6)(i) through (iii), using volumetric flow rate as a surrogate. You must determine the volumetric flow rate in accordance with paragraph (a)(7)(iii) of this section.

(i) The volumetric flow rate per seal must not exceed 10 standard cubic feet per minute (scfm) per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 10 scfm. If the volumetric flow rate, measured in accordance with paragraph (a)(7)(iii) of this section exceeds 10 scfm multiplied by the number of dry seals connected to the vent, the seals connected to the measured vent must be repaired as provided in paragraph (a)(8) of this section.

(ii) You must conduct your first volumetric flow rate measurement from your centrifugal compressor equipped with a dry seal on or before 8,760 hours of operation after May 7, 2024 or on or before 8,760 hours of operation after startup, whichever date is later.

(iii) You must conduct subsequent volumetric flow rate measurements from your centrifugal compressor equipped with dry seals on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with the 10 scfm volumetric flow rate per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 10 scfm.

(7) You must determine the volumetric flow rate for your centrifugal compressor, as specified in paragraphs (a)(7)(i) through (iii) of this section.

(i) You must determine the volumetric flow rate from your self-contained wet seal centrifugal compressor wet seal as specified in paragraph (a)(7)(i)(A) or (B) of this section. If the volumetric flow rate exceeds 3 scfm multiplied by the number of wet seals connected to the vent, the wet seals connected to the measured vent must be repaired as provided in paragraph (a)(8) of this section.

(A) For self-contained wet seal centrifugal compressors in operating-mode or in standby-pressurized-mode, determine volumetric flow rate at standard conditions from each self-contained wet seal centrifugal compressor wet seal using one of the methods specified in paragraphs (a)(7)(i)(A)(*1*) through (*3*) of this section.

(*1*) You may choose to use any of the methods set forth in § 60.5386b(a) to screen for leaks/emissions. For the purposes of this paragraph, when using any of the methods in § 60.5386b(a), emissions are detected whenever a leak is detected according to the method. If emissions are detected using the methods set forth in § 60.5386b(a), then you must use one of the methods specified in paragraph (a)(7)(i)(A)(*2*) or (*3*) of this section to determine the volumetric flow rate. If emissions are not detected using the methods in § 60.5386b(a), then you may assume that the volumetric emissions are zero.

(*2*) Use a temporary or permanent flow meter according to methods set forth in § 60.5386b(b).

(*3*) Use a high-volume sampler according to the method set forth in § 60.5386b(c).

(B) For conducting measurements on manifolded groups of self-contained wet seal centrifugal compressor seals, you must determine the volumetric flow rate from the self-contained wet seal centrifugal compressor seal as specified in paragraph (a)(7)(i)(B)(*1*) or (*2*) of this section.

(*1*) Measure at a single point in the manifold downstream of all self-contained wet seal centrifugal compressor seal inputs and, if practical, prior to comingling with other non-compressor emission sources.

(*2*) Determine the volumetric flow rate at standard conditions from the common stack using one of the methods specified in paragraph (a)(7)(i)(A)(*1*) through (*3*) of this section.

(ii) You must determine the volumetric flow rate from your centrifugal compressor on the Alaska North Slope equipped with sour seal oil separator and capture system as specified in paragraph (a)(7)(ii)(A) or (B) of this section. If the volumetric flow rate exceeds 9 scfm multiplied by the number of wet seals connected to the vent, the wet seals connected to the measured vent must be repaired as provided in paragraph (a)(8) of this section.

(A) For centrifugal compressors in operating-mode or in standby-pressurized-mode, determine volumetric flow rate at standard conditions from each centrifugal compressor on the Alaska North Slope equipped with a sour seal oil separator and capture system using one of the methods specified in paragraphs (a)(7)(ii)(A)(*1*) through (*3*) of this section.

(*1*) You may choose to use any of the methods set forth in § 60.5386b(a) to screen for leaks/emissions. For the purposes of this paragraph, when using any of the methods in § 60.5386b(a), emissions are detected whenever a leak is detected according to the method. If emissions are detected using the methods set forth in § 60.5386b(a), then you must use one of the methods specified in paragraph (a)(7)(ii)(A)(*2*) or (*3*) of this section to determine the volumetric flow rate. If emissions are not detected using the methods in § 60.5386b(a), then you may assume that the volumetric emissions are zero.

(*2*) Use a temporary or permanent flow meter according to methods set forth in § 60.5386b(b).

(*3*) Use a high-volume sampler according to the method set forth in § 60.5386b(c).

(B) For conducting measurements on manifolded groups of centrifugal compressors on the Alaska North Slope equipped with sour seal oil separators and capture systems, you must determine the volumetric flow rate from the centrifugal compressors equipped with sour seal oil separators and capture systems as specified in paragraph (a)(7)(ii)(B)(*1*) or (*2*) of this section.

(*1*) Measure at a single point in the manifold downstream of all centrifugal compressors on the Alaska North Slope equipped with sour seal oil separator and capture system wet seal inputs and, if practical, prior to comingling with other non-compressor emission sources.

(*2*) Determine the volumetric flow rate at standard conditions from the common stack using one of the methods specified in paragraph (a)(7)(ii)(A)(*1*) through (*3*) of this section.

(iii) You must determine the volumetric flow rate from your centrifugal compressor equipped with dry seals as specified in paragraph (a)(7)(iii)(A) or (B) of this section. If the volumetric flow rate exceeds 10 scfm multiplied by the number of dry seals connected to the vent, the dry seals connected to the measured vent must be repaired as provided in paragraph (a)(8) of this section.

(A) For centrifugal compressors equipped with dry seals in operating-mode or in standby-pressurized-mode, determine volumetric flow rate at standard conditions from each centrifugal compressor equipped with dry seals using one of the methods specified in paragraphs (a)(7)(iii)(A)(*1*) through (*3*) of this section.

(*1*) You may choose to use any of the methods set forth in § 60.5386b(a) to screen for leaks/emissions. For the purposes of this paragraph, when using any of the methods in § 60.5386b(a), emissions are detected whenever a leak is detected according to the method. If emissions are detected using the methods set forth in § 60.5386b(a), then you must use one of the methods specified in paragraph (a)(7)(iii)(A)(*2*) or (*3*) of this section to determine the volumetric flow rate. If emissions are not detected using the methods in § 60.5386b(a), then you may assume that the volumetric emissions are zero.

(*2*) Use a temporary or permanent flow meter according to methods set forth in § 60.5386b(b).

(*3*) Use a high-volume sampler according to the method set forth in § 60.5386b(c).

(B) For conducting measurements on manifolded groups of centrifugal compressors equipped with dry seals, you must determine the volumetric flow rate from the dry seal centrifugal compressors as specified in paragraph (a)(7)(iii)(B)(*1*) or (*2*) of this section.

(*1*) Measure at a single point in the manifold downstream of all centrifugal compressors equipped with dry seals inputs and, if practical, prior to comingling with other non-compressor emission sources.

(*2*) Determine the volumetric flow rate at standard conditions from the common stack using one of the methods specified in paragraph (a)(7)(iii)(A)(*1*) through (*3*) of this section.

(8) The seal must be repaired within 90 calendar days after the date of the volumetric emissions measurement that exceeds the applicable required flow rate per seal. You must conduct follow-up volumetric flow rate measurements from seal vents using the methods specified in paragraph (a)(7) of this section within 15 days after the repair to document that the rate has been reduced to less than the applicable required flow rate per seal. If the individual seals are manifolded to a single open-ended vent line or vent, the volumetric flow rate must be reduced to less than the sum of the individual seals multiplied by the applicable required flow rate per seal specified in paragraph (a)(4) through (6) of this section, as applicable. Delay of repair will be allowed if the conditions in paragraphs (a)(8)(i) or (ii) of this section are met.

(i) If the repair of the wet or dry seal is technically infeasible, would require a vent blowdown, a compressor station shutdown, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown for maintenance, after a scheduled vent blowdown, or within 2 years of the date of the volumetric emissions measurement that exceeds the applicable required flow rate per seal, whichever is earliest. A vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel.

(ii) If the repair requires replacement of the compressor seal or a part thereof, but the replacement cannot be acquired and installed within the repair timelines specified under this section due to the condition specified in paragraph (a)(8)(ii)(A) of this section, the repair must be completed in accordance with paragraph (a)(8)(ii)(B) of this section and documented in accordance with § 60.5420b(c)(4)(iii)(F) through (H).

(A) Seal or part thereof supplies had been sufficiently stocked but are depleted at the time of the required repair.

(B) The required replacement must be ordered no later than 10 calendar days after the centrifugal compressor seal is added to the delay of repair list due to parts unavailability. The repair must be completed as soon as practicable, but no later than 30 calendar days after receipt of the replacement seal or part, unless the repair requires a compressor station shutdown. If the repair requires a compressor station shutdown, the repair must be completed in accordance with the timeframe specified in paragraph (a)(8)(i) of this section.

(9) As an alternative to meeting the requirements for centrifugal compressors with dry seals specified in paragraphs (a)(6) through (8) of this section, owners or operators are allowed to comply with the standard by meeting the requirements specified in paragraphs (a)(9)(i) and (ii), or (a)(9)(iii) of this section.

(i) You must reduce methane and VOC emissions from each centrifugal compressor dry seal system by 95.0 percent.

(ii) If you use a control device to reduce emissions, you must equip the dry seal system with a cover that meets the requirements of § 60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and the closed vent system must be routed to a control device that meets the conditions specified in § 60.5412b.

(iii) As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process. If you route the emissions to a process, you must equip the dry seal system with a cover that meets the requirements of § 60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of § 60.5411b(a) and (c).

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5410b(d).

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5415b(d).

(d) You must perform the reporting as required by § 60.5420b(b)(1) and (5), and (b)(11) through (13), as applicable; and the recordkeeping as required by § 60.5420b(c)(4), and (8) through (13), as applicable.

§ 60.5385b What GHG and VOC standards apply to reciprocating compressor affected facilities?

Each reciprocating compressor affected facility must comply with the GHG and VOC standards, using volumetric flow rate as a surrogate, in paragraphs (a) through (c) of this section, or the GHG and VOC standards in paragraph (d) of this section. You must also comply with the requirements in paragraphs (e) through (g) of this section.

(a) The volumetric flow rate of each cylinder, measured in accordance with paragraph (b) or (c) of this section, must not exceed 2 scfm per individual cylinder. If the individual cylinders are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section and determine the volumetric flow rate per cylinder in accordance with paragraph (b) or (c) of this section. If the volumetric flow rate, measured in accordance with paragraph (b) or (c) of this section, for a cylinder exceeds 2 scfm per cylinder (or a combined volumetric flow rate greater than the number of compression cylinders multiplied by 2 scfm), the rod packing or packings must be repaired or replaced as provided in paragraph (a)(3) of this section.

(1) You must conduct your first volumetric flow rate measurements from your reciprocating compressor rod packing vent on or before 8,760 hours of operation after May 7, 2024, or on or before 8,760 hours of operation after last rod packing replacement, or on or before 8,760 hours of operation after startup, whichever date is later.

(2) You must conduct subsequent volumetric flow rate measurements from your reciprocating compressor rod packing vent on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with the applicable volumetric flow rate of 2 scfm per cylinder (or a combined volumetric flow rate greater than the number of compression cylinders multiplied by 2 scfm), or on or before 8,760 hours of operation after last rod packing replacement, whichever date is later.

(3) The rod packing must be repaired or replaced within 90 calendar days after the date of the volumetric emissions measurement that exceeded 2 scfm per cylinder. You must conduct follow-up volumetric flow rate measurements from compressor vents using the methods specified in paragraph (b) of this section within 15 days after the repair (or rod packing replacement) to document that the rate has been reduced to less than 2 scfm per cylinder. Delay of repair will be allowed if the conditions in paragraphs (a)(3)(i) or (ii) of this section are met.

(i) If the repair (or rod packing replacement) is technically infeasible, would require a vent blowdown, a compressor station shutdown, or would be unsafe to repair during operation of the unit, the repair (or rod packing replacement) must be completed during the next scheduled compressor station shutdown for maintenance, after a scheduled vent blowdown, or within 2 years of the date of the volumetric emissions measurement that exceeds the applicable required flow rate per cylinder, whichever is earliest. A vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel.

(ii) If the repair requires replacement of the rod packing or a part, but the replacement cannot be acquired and installed within the repair timelines specified under this section due to the condition specified in paragraph (a)(3)(ii)(A) of this section, the repair must be completed in accordance with paragraph (a)(3)(ii)(B) of this section and documented in accordance with § 60.5420b(c)(5)(viii) through (x).

(A) Rod packing or part supplies had been sufficiently stocked but are depleted at the time of the required repair.

(B) The required rod packing or part replacement must be ordered no later than 10 calendar days after the reciprocating compressor is added to the delay of repair list due to parts unavailability. The repair must be completed as soon as practicable, but no later than 30 calendar days after receipt of the replacement rod packing or part, unless the repair requires a compressor station shutdown. If the repair requires a compressor station shutdown, the repair must be completed in accordance with the timeframe specified in paragraph (a)(3)(i) of this section.

(b) You must determine the volumetric flow rate per cylinder from your reciprocating compressor as specified in paragraph (b)(1) or (2) of this section.

(1) For reciprocating compressor rod packing equipped with an open-ended vent line on compressors in operating or standby pressurized mode, determine the volumetric flow rate of the rod packing using one of the methods specified in paragraphs (b)(1)(i) through (iii) of this section.

(i) Determine the volumetric flow rate at standard conditions from the open-ended vent line using a high-volume sampler according to methods set forth in § 60.5386b(c).

(ii) Determine the volumetric flow rate at standard conditions from the open-ended vent line using a temporary or permanent meter, according to methods set forth in § 60.5386b(b).

(iii) Any of the methods set forth in § 60.5386b(a) to screen for leaks and emissions. For the purposes of this paragraph, emissions are detected whenever a leak is detected according to any of the methods in § 60.5386b(a). If emissions are detected using the methods set forth in § 60.5386b(a), then you must use one of the methods specified in paragraph (b)(1)(i) and (ii) of this section to determine the volumetric flow rate per cylinder. If emissions are not detected using the methods in § 60.5386b(a), then you may assume that the volumetric flow rate is zero.

(2) For reciprocating compressor rod packing not equipped with an open-ended vent line on compressors in operating or standby pressurized mode, you must determine the volumetric flow rate of the rod packing using the methods specified in paragraphs (b)(2)(i) and (ii) of this section.

(i) You must use the methods described in § 60.5386b(a) to conduct leak detection of emissions from the rod packing case into an open distance piece, or, for compressors with a closed distance piece, you must conduct annual leak detection of emissions from the rod packing vent, distance piece vent, compressor crank case breather cap, or other vent emitting gas from the rod packing.

(ii) You must measure emissions found in paragraph (b)(2)(i) of this section using a meter or high-volume sampler according to methods set forth in § 60.5386b(b) or (c).

(c) For conducting measurements on manifolded groups of reciprocating compressor affected facilities, you must determine the volumetric flow rate from reciprocating compressor rod packing vent as specified in paragraph (c)(1) and (2) of this section.

(1) Measure at a single point in the manifold downstream of all compressor vent inputs and, if practical, prior to comingling with other non-compressor emission sources.

(2) Determine the volumetric flow rate per cylinder at standard conditions from the common stack using one of the methods specified in paragraph (c)(2)(i) through (iv) of this section.

(i) A temporary or permanent flow meter according to the methods set forth in § 60.5386b(b).

(ii) A high-volume sampler according to methods set forth § 60.5386b(c).

(iii) An alternative method, as set forth in § 60.5386b(d).

(iv) Any of the methods set forth in § 60.5386b(a) to screen for emissions. For the purposes of this paragraph, emissions are detected whenever a leak is detected when using any of the methods in § 60.5386b(a). If emissions are detected using the methods set forth in § 60.5386b(a), then you must use one of the methods specified in paragraph (c)(2)(i) through (iii) of this section to determine the volumetric flow rate per cylinder. If emissions are not detected using the methods in § 60.5386b(a), then you may assume that the volumetric flow rate is zero.

(d) As an alternative to complying with the GHG and VOC standards in paragraphs (a) through (c) of this section, owners or operators can meet the requirements specified in paragraph (d)(1), (2), or (3) of this section.

(1) Collect the methane and VOC emissions from your reciprocating compressor rod packing using a rod packing emissions collection system that is operated to route the rod packing emissions to a process. In order to comply with this option, you must equip the reciprocating compressor with a cover that meets the requirements of § 60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of § 60.5411b(a) and (c).

(2) Reduce methane and VOC emissions from each rod packing emissions collection system by using a control device that reduces methane and VOC emissions by 95.0 percent. In order to comply with this option, you must equip the reciprocating compressor with a cover that meets the requirements of § 60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and the closed vent system must be routed to a control device that meets the conditions specified in § 60.5412b.

(3) As an alternative to conducting the required volumetric flow rate measurements under paragraph (a) of this section, an owner or operator can choose to comply by replacing the rod packing on or before 8,760 hours of operation after initial startup, on or before 8,760 hours of operation after May 7, 2024, on or before 8,760 hours of operation after the previous flow rate measurement, or on or before 8,760 hours of operation after the date of the most recent compressor rod packing replacement, whichever date is later.

(e) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5410b(e).

(f) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5415b(g).

(g) You must perform the reporting requirements as specified in § 60.5420b(b)(1), (6), (11), and (12), as applicable; and the recordkeeping requirements as specified in § 60.5420b(c)(5) and (8) through (13), as applicable.

§ 60.5386b What test methods and procedures must I use for my centrifugal compressor and reciprocating compressor affected facilities?

(a) You must use one of the methods described in paragraph (a)(1) and (2) of this section to screen for emissions or leaks from the reciprocating compressor rod packing when complying with § 60.5385b(b)(1)(iii) and from applicable wet seal centrifugal compressor and dry seal centrifugal compressor vents when complying with § 60.5380b(a)(3) through (6).

(1) ***OGI instrument.*** Use an OGI instrument for equipment leak detection as specified in either paragraph (a)(1)(i) or (ii) of this section. For the purposes of paragraphs (a)(1)(i) and (ii) of this section, any visible emissions observed by the OGI instrument from reciprocating rod packing or compressor dry seal vent is a leak.

(i) ***OGI instrument as specified in appendix K of this part.*** For reciprocating compressor, applicable wet seal centrifugal compressor, and dry seal centrifugal compressor affected facilities located at onshore natural gas processing plants, use an OGI instrument to screen for emissions from reciprocating rod packing or centrifugal compressor dry seal vent in accordance with the protocol specified in appendix K of this part.

(ii) ***OGI instrument as specified in § 60.5397b of this subpart.*** For reciprocating compressor, applicable wet seal centrifugal compressor, and dry seal centrifugal compressor affected facilities located at centralized production facilities, compressor stations, or other location that is not an onshore natural gas processing plant, use an OGI instrument to screen for emissions from reciprocating rod packing or compressor dry seals in accordance with the elements of § 60.5397b(c)(7).

(2) ***Method 21.*** Use Method 21 in appendix A-7 to this part according to § 60.5403b(b)(1) and (2). For the purposes of this section, an instrument reading of 500 parts per million by volume (ppmv) above background or greater is a leak.

(b) You must determine natural gas volumetric flow rate using a rate meter which meets the requirement in Method 2D in appendix A-1 of this part. Rate meters must be calibrated on an annual basis according to the requirements in Method 2D.

(c) You must use a high-volume sampler to measure emissions of the reciprocating compressor rod packing. applicable centrifugal compressor wet seal vent, or centrifugal compressor dry seal vent in accordance with paragraphs (c)(1) through (7) of this section.

(1) You must use a high-volume sampler designed to capture the entirety of the emissions from the applicable vent and measure the entire range of methane concentrations being emitted as well as the total volumetric flow at standard conditions. You must develop a standard operating procedure for this device and document these procedures in the appropriate monitoring plan. In order to get reliable results, persons using this device should be knowledgeable in its operation and the requirements in this section.

(2) This procedure may involve hazardous materials, operations, and equipment. This procedure may not address all of the safety problems associated with its use. It is the responsibility of the user of this procedure to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this procedure.

(3) The high-volume sampler must include a methane gas sensor(s) which meets the requirements in paragraphs (c)(3)(i) through (iii) of this section.

(i) The methane sensor(s) must be selective to methane with minimal interference, less than 2.5 percent for the sum of responses to other compounds in the gas matrix. You must document the minimal interference though empirical testing or through data provided by the manufacturer of the sensor.

(ii) The methane sensor(s) must have a measurement range over the entire expected range of concentrations.

(iii) The methane sensor(s) must be capable of taking a measurement once every second, and the data system must be capable of recording these results for each sensor at all times during operation of the sampler.

(4) The high-volume sampler must be designed such that it is capable of sampling sufficient volume in order to capture all emissions from the applicable vent. Your high-volume sampler must include a flow measurement sensor(s) which meets the requirements of paragraphs (c)(4)(i) and (ii) of this section.

(i) The flow measurement sensor must have a measurement range over the entire expected range of flow rates sampled. If needed multiple sensors may be used to capture the entire range of expected flow rates.

(ii) The flow measurement sensor(s) must be capable of taking a measurement once every second, and the data system must be capable of recording these results for each sensor at all times during operation of the sampler.

(5) You must calibrate your methane sensor(s) according to the procedures in paragraphs (c)(5)(i)(A) and (B) of this section, and flow measurement sensors must be calibrated according to the procedures in paragraph (c)(5)(ii) of this section.

(i) For Methane Sensor Calibration:

(A) Initially and on a semi-annual basis, determine the linearity at four points through the measurement range for each methane sensor using methane gaseous calibration cylinder standards. At each point, the difference between the cylinder value and the sensor reading must be less than 5 percent of the respective calibration gas value. If the sensor does not meet this requirement, perform corrective action on the sensor, and do not use the sampler until these criteria can be met.

(B) Prior to and at the end of each testing day, challenge each sensor at two points, a low point, and a mid-point, using methane gaseous calibration cylinder standards. At each point, the difference between the cylinder value and the sensor reading must be less than 5 percent of the respective calibration gas value. If the sensor does not meet this requirement, perform corrective action on the sensor and do not use the sampler again until these criteria can be met. If the post-test calibration check fails at either point, invalidate the data from all tests performed subsequent to the last passing calibration check.

(ii) Flow measurement sensors must meet the requirements in Method 2D in appendix A-1 of this part. Rate meters must be calibrated on an annual basis according to the requirements in Method 2D. If your flow sensor relies on ancillary temperature and pressure measurements to correct the flow rate to standard conditions, the temperature and pressure sensors must also be calibrated on an annual basis. Standard conditions are defined as 20 °C (68 °F) and 760 mm Hg (29.92 in. Hg).

(6) You must conduct sampling of the reciprocating compressor rod packing, applicable wet seal centrifugal compressor, or dry seal centrifugal compressor vent in accordance with the procedures in paragraphs (c)(6)(i) through (v) of this section.

(i) The instrument must be operated consistent with manufacturer recommendations; users are encouraged to develop a standard operating procedure to document the exact procedures used for sampling.

(ii) Identify the rod packing, applicable wet seal centrifugal compressor, or dry seal centrifugal compressor vent to be measured and record the signal to noise ratio (S/N) of the engine. Collect a background methane sample in ppmv for a minimum of one minute and record the result along with the date and time.

(iii) Approach the vent with the sample hose and adjust the sampler so that you are measuring at the full flow rate. Then, adjust the flow rate to ensure the measured methane concentration is within the calibrated range of the methane sensor and minimum methane concentration is at least 2 ppmv higher than the background concentration. Sample for a period of at least one minute and record the average flow rate in standard cubic feet per minute and the methane sample concentration in ppmv, along with the date and time. Standard conditions are defined as 20 °C (68 °F) and 760 mm Hg (29.92 in. Hg).

(iv) Calculate the leak rate according to the following equation:

Equation 1 to paragraph (c)(6)(iv)

$$Q = V\left(\frac{CH4_S - CH4_B}{1000000}\right)$$

Where:
$CH4_B$ = background methane concentration, ppmv
$CH4_S$ = methane sample concentration, ppmv
V = Average flow rate of the sampler, scfm
Q = Methane emission rate, scfm

(v) You must collect at least three separate one-minute measurements and determine the average leak rate. The relative percent difference of these three separate samples should be less than 10 percent.

(7) If the measured natural gas flow determined as specified in paragraph (c)(6) of this section exceeds 70.0 percent of the manufacturer's reported maximum sampling flow rate you must either use a temporary or permanent flow meter according to paragraph (b) of this section or use another method meeting the requirements in paragraph (d) of this section to determine the leak or flow rate.

(d) As an alternative to a high-volume sampler, you may use any other method that has been validated in accordance with the procedures specified in Method 301 in appendix A in 40 CFR part 63, subject to Administrator approval, as specified in § 60.8(b).

§ 60.5390b What GHG and VOC standards apply to process controller affected facilities?

Each process controller affected facility must comply with the GHG and VOC standards in this section.

(a) You must design and operate each process controller affected facility with zero methane and VOC emissions to the atmosphere, except as provided in paragraph (b) of this section.

(1) If you comply by routing the emissions to a process, emissions must be routed to a process through a closed vent system.

(2) If you comply by using a self-contained natural gas-driven process controller, you must design and operate each self-contained natural gas-driven process controller with no identifiable emissions, as demonstrated by § 60.5416b(b).

(b) For each process controller affected facility located at a site in Alaska that does not have access to electrical power, you may comply with either paragraphs (b)(1) and (2) of this section or with paragraph (b)(3) of this section, instead of complying with paragraph (a) of this section.

(1) With the exception of natural gas-driven continuous bleed controllers that meet the condition in paragraph (b)(1)(i) of this section and that comply with paragraph (b)(1)(ii) of this section, each natural gas-driven continuous bleed process controller in the process controller affected facility must have a bleed rate less than or equal to 6 standard cubic feet per hour (scfh).

(i) A natural gas-driven continuous bleed process controller with a bleed rate higher than 6 scfh may be used if the requirements of paragraph (b)(1)(ii) of this section are met.

(ii) You demonstrate that a natural gas-driven continuous bleed controller with a bleed rate higher than 6 scfh is required. The demonstration must be based on the specific functional need, including but not limited to response time, safety, or positive actuation.

(2) Each natural gas-driven intermittent vent process controller in the process controller affected facility must comply with the requirements in paragraphs (b)(2)(i) and (ii) of this section.

(i) Each natural gas-driven intermittent vent process controller must not emit to the atmosphere during idle periods.

(ii) You must monitor each natural gas-driven intermittent vent process controller to ensure that it is not emitting to the atmosphere during idle periods, as specified in paragraphs (b)(2)(ii)(A) through (C) of this section.

(A) Monitoring must be conducted at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site, as specified in § 60.5397b(g).

(B) You must include the monitoring of each natural gas-driven intermittent vent process controller in the monitoring plan required in § 60.5397b(b).

(C) When monitoring identifies emissions to the atmosphere from a natural gas-driven intermittent vent controller during idle periods, you must take corrective action by repairing or replacing the natural gas-driven intermittent vent process controller within 5 calendar days of the date the emissions to the atmosphere were detected. After the repair or replacement of a natural gas-driven intermittent vent process controller, you must re-survey the natural gas-driven intermittent vent process controller within five days to verify that it is not venting emissions during idle periods.

(3) You must reduce methane and VOC emissions from all controllers in the process controller affected facility by 95.0 percent. You must route emissions through a closed vent system to a control device that meets the conditions specified in § 60.5412b.

(c) If you route process controller emissions to a process or a control device, you must route the process controller affected facility emissions through a closed vent system that meets the requirements of § 60.5411b(a) and (c).

(d) You must demonstrate initial compliance with standards that apply to process controller affected facilities as required by § 60.5410b(f).

(e) You must demonstrate continuous compliance with standards that apply to process controller affected facilities as required by § 60.5415b(h).

(f) You must perform the reporting as required by § 60.5420b(b)(1), (7), and (11) through (13), as applicable, and the recordkeeping as required by § 60.5420b(c)(6), (8), and (10) through (13), as applicable.

§ 60.5393b What GHG and VOC standards apply to pump affected facilities?

Each pump affected facility must comply with the GHG and VOC standards in this section.

(a) For each pump affected facility meeting the criteria specified in paragraphs (a)(1) or (2) of this section, you must design and operate the pump affected facility with zero methane and VOC emissions to the atmosphere. If you comply by routing the pump affected facility emissions to a process, the emissions must be routed to the process through a closed vent system.

(1) The pump affected facility is located at a site that has access to electrical power.

(2) The pump affected facility is located at a site that does not have access to electrical power and has three or more natural gas-driven diaphragm pumps.

(b)

(1) For each pump affected facility located at a site that does not have access to electrical power and that also has fewer than three natural gas-driven diaphragm pumps, you must comply with paragraph (b)(2) or (3) of this section, except as provided in paragraphs (b)(4) through (8) of this section.

(2) Emissions from the pump affected facility must be routed through a closed vent system to a process if a vapor recovery unit is onsite.

(3) If a vapor recovery unit is not onsite, you must reduce methane and VOC emissions from the pump affected facility by 95.0 percent. You must route affected pump facility emissions through a closed vent system to a control device meeting the conditions specified in § 60.5412b.

(4) You are not required to install an emissions control device or a vapor recovery unit, if such a unit is necessary to enable emissions to be routed to a process, solely for the purpose of complying with the requirements of paragraph (b)(2) or (3) of this section. If no control device capable of achieving a 95.0 percent emissions reduction and no vapor recovery unit is present on site, you must comply with paragraph (b)(5) or (6) of this section, as applicable. For the purposes of this section, boilers and process heaters are not considered to be control devices.

(5) If an emissions control device is on site but is unable to achieve a 95.0 percent emissions reduction, you must route the pump affected facility emissions through a closed vent system to that control device. You must certify that there is no vapor recovery unit on site and that there is no control device capable of achieving a 95.0 percent emissions reduction on site.

(6) If there is no vapor recovery unit on site and no emission control device is on site, you must certify that there is no vapor recovery unit or emissions control device on site. If you subsequently install a control device or vapor recovery unit, you must meet the requirements of paragraphs (b)(6)(i) and (ii) of this section.

(i) You must be in compliance with the requirements of paragraphs (b)(1) through (3) of this section, as applicable, within 30 days of startup of the control device or vapor recovery unit.

(ii) You must maintain the records in § 60.5420b(c)(15)(ii) and (v), as applicable. You are no longer required to maintain the records in § 60.5420b(c)(15)(vi).

(7) If an owner or operator complying with paragraph (b)(1) of this section determines, through an engineering assessment, that routing the pump affected facility emissions to a control device or to a process is technically infeasible, the requirements specified in paragraphs (b)(7)(i) through (iii) of this section must be met.

(i) The owner or operator must conduct the assessment of technical infeasibility in accordance with the criteria in paragraph (b)(7)(ii) of this section and have it certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of the pump affected facility and the control device or processes at the site in accordance with paragraph (b)(7)(iii) of this section.

(ii) The assessment of technical infeasibility to route emissions from the pump affected facility to an existing control device or process must include, but is not limited to, safety considerations, distance from the control device or process, pressure losses and differentials in the closed vent system, and the ability of the control device or process to handle the pump affected facility emissions which are routed to them. The assessment of technical infeasibility must be prepared under the direction or supervision of the qualified professional engineer or in-house engineer who signs the certification in accordance with paragraph (b)(7)(iii) of this section.

(iii) The following certification, signed and dated by the qualified professional engineer or in-house engineer, must state: "I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was prepared pursuant to the requirements of § 60.5393b(b)(5)(ii). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(8) If the pump affected facility emissions are routed to a control device or process and the control device or process is subsequently removed from the location or is no longer available, such that there is no option to route to a control device or process, you are no longer required to be in compliance with the requirements of paragraphs (b)(2) or (3) of this section, and instead must comply with paragraph (b)(6) of this section.

(c) If you use a control device or route to a process to reduce emissions, you must route the pump affected facility emissions through a closed vent system that meets the requirements of § 60.5411b(a) and (c).

(d) You must demonstrate initial compliance with standards that apply to pump affected facilities as required by § 60.5410b(g).

(e) You must demonstrate continuous compliance with the standards that apply to pump affected facilities as required by § 60.5415b(e).

(f) You must perform the reporting as required by § 60.5420b(b)(1), (10), and (11) through (13), as applicable; and the recordkeeping as required by § 60.5420b(c)(8), (10) through (13), and (15), as applicable.

§ 60.5395b What GHG and VOC standards apply to storage vessel affected facilities?

Each storage vessel affected facility must comply with the GHG and VOC standards in this section, except as provided in paragraph (e) of this section.

(a) ***General requirements.*** You must comply with the requirements of paragraphs (a)(1) and (2) of this section. After 12 consecutive months of compliance with paragraph (a)(2) of this section, you may continue to comply with paragraph (a)(2) of this section, or you may comply with paragraph (a)(3) of this section, if applicable. If you choose to meet the requirements of paragraph (a)(3) of this section, you are not required to comply with the requirements of paragraph (a)(2) of this section except as provided in paragraphs (a)(3)(i) and (ii) of this section.

(1) Determine the potential for methane and VOC emissions in accordance with § 60.5365b(e)(2).

(2) Reduce methane and VOC emissions by 95.0 percent.

(3) Maintain the uncontrolled actual VOC emissions at less than 4 tpy and the actual methane emissions at less than 14 tpy from the storage vessel affected facility without considering control. Prior to using the uncontrolled actual VOC and methane emission rates for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy and the uncontrolled actual methane emissions have remained less than 14 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual rolling 12-month determination VOC and methane emissions rates each month. The uncontrolled actual VOC and methane emissions must be calculated using a generally accepted model or calculation methodology which account for flashing, working and breathing losses, and the calculations must be based on the actual average throughput, temperature, and separator pressure for the month. You may no longer comply with this paragraph and must instead comply with paragraph (a)(2) of this section if your storage vessel affected facility meets the conditions specified in paragraphs (a)(3)(i) or (ii) of this section.

(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (a)(2) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.

(ii) If the rolling 12-month emissions determination required in this section indicates that VOC emissions increase to 4 tpy or greater or the methane emissions increase to 14 tpy or greater from your storage vessel affected facility and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (a)(2) of this section within 30 days of the monthly determination.

(b) ***Control requirements.***

(1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce methane and VOC emissions from your storage vessel affected facility, you must meet all of the design and operational criteria specified in paragraphs (b)(1)(i) through (iii) of this section.

(i) Each storage vessel in the tank battery must be equipped with a cover that meets the requirements of § 60.5411b(b);

(ii) The tank battery must be equipped with one or more closed vent system that meets the requirements of § 60.5411b(a) and (c); and

(iii) The vapors collected in paragraphs (b)(1)(ii) of this section must be routed to a control device that meets the conditions specified in § 60.5412b. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) For storage vessel affected facilities that do not have flashing emissions and that are not located at well sites or centralized production facilities, you may use a floating roof to reduce emissions. If you use a floating roof to reduce emissions, you must meet the requirements of § 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in subpart Kb of this part. You must submit a statement that you are complying with § 60.112b(a)(1) or (2) with the initial annual report specified in § 60.5420b(b)(1) and (8).

(c) ***Requirements for storage vessel affected facilities that are removed from service or returned to service.*** If you remove a storage vessel affected facility from service or remove a portion of a storage vessel affected facility from service, you must comply with the applicable paragraphs (c)(1) through (4) of this section. A storage vessel is not an affected facility under this subpart for the period that it is removed from service.

(1) For a storage vessel affected facility to be removed from service, you must comply with the requirements of paragraphs (c)(1)(i) and (ii) of this section.

(i) You must completely empty and degas each storage vessel, such that each storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification as required in § 60.5420b(b)(6)(viii) in your next annual report, identifying each storage vessel affected facility removed from service during the reporting period and the date of its removal from service.

(2) For a portion of a storage vessel affected facility to be removed from service, you must comply with the requirements of paragraphs (c)(2)(i) through (iv) of this section.

(i) You must completely empty and degas the storage vessel(s), such that the storage vessel(s) no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must disconnect the storage vessel(s) from the tank battery by isolating the storage vessel(s) from the tank battery such that the storage vessel(s) is no longer manifolded to the tank battery by liquid or vapor transfer.

(iii) You must submit a notification as required in § 60.5420b(b)(8)(viii) in your next annual report, identifying each storage vessel removed from service during the reporting period, the impacted storage vessel affected facility, and the date of its removal from service.

(iv) The remaining storage vessel(s) in the tank battery remain a storage vessel affected facility and must continue to comply with the applicable requirements of paragraphs (a) and (b) of this section.

(3) If a storage vessel identified in paragraph (c)(1)(ii) or (c)(2)(iii) of this section is returned to service, you must determine its affected facility status as provided in § 60.5365b(e)(6).

(4) For each storage vessel affected facility or portion of a storage vessel affected facility returned to service during the reporting period, you must submit a notification in your next annual report as required in § 60.5420b(b)(8)(ix), identifying each storage vessel affected facility or portion of a storage vessel affected facility and the date of its return to service.

(d) ***Compliance, notification, recordkeeping, and reporting.*** You must comply with paragraphs (d)(1) through (3) of this section.

(1) You must demonstrate initial compliance with standards as required by § 60.5410b(j).

(2) You must demonstrate continuous compliance with standards as required by § 60.5415b(i).

(3) You must perform the required reporting as required by § 60.5420b(b)(1) and (8) and (b)(11) through (13), as applicable; and the recordkeeping as required by § 60.5420b(c)(7) and (c)(8) through (13), as applicable.

(e) ***Exemptions.*** This subpart does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in subpart Kb of this part, and 40 CFR part 63, subparts G, CC, HH, or WW.

§ 60.5397b What GHG and VOC standards apply to fugitive emissions components affected facilities?

This section applies to fugitive emissions components affected facilities. You must comply with the requirements of paragraphs (a) through (l) of this section to reduce fugitive emissions of methane and VOC. The requirements of this section are independent of the cover and closed vent system requirements of § 60.5411b.

(a) ***General requirements.*** You must monitor all fugitive emissions components affected facilities in accordance with paragraphs (b) through (g) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (h) of this section. You must demonstrate initial compliance in accordance with paragraph (i) of this section. You must keep records in accordance with paragraph (j) of this section and report in accordance with paragraph (k) of this section. You must meet the requirements for well closures in accordance with paragraph (l) of this section.

(b) ***Develop fugitive emissions monitoring plan.*** You must develop a fugitive emissions monitoring plan that covers all fugitive emissions components affected facilities within each company-defined area in accordance with paragraphs (c) and (d) of this section.

(c) ***Elements of fugitive emissions monitoring plan.*** Your fugitive emissions monitoring plan must include the elements specified in paragraphs (c)(1) through (8) of this section, at a minimum.

(1) Frequency for conducting surveys. Surveys must be conducted at least as frequently as required by paragraphs (f) and (g) of this section.

(2) Technique for determining fugitive emissions (*i.e.,* AVO or other detection methods, Method 21 of appendix A-7 to this part, and/or OGI and meeting the requirements of paragraphs (c)(7)(i) through (vii) of this section).

(3) Manufacturer and model number of fugitive emissions detection equipment to be used, if applicable.

(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (h) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) If you are using OGI, your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

(i) Verification that your OGI equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification, and may either be performed by the facility, by the manufacturer, or by a third party. For the purposes of complying with the fugitive emissions monitoring program with OGI, fugitive emissions are defined as any visible emissions observed using OGI.

(A) Your OGI equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.

(B) Your OGI equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60 g/hr from a quarter inch diameter orifice.

(ii) Procedure for a daily verification check.

(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(v) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (*e.g.,* steam).

(vi) Training and experience needed prior to performing surveys.

(vii) Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.

(8) If you are using Method 21 of appendix A-7 to this part, your plan must also include the elements specified in paragraphs (c)(8)(i) through (iv) of this section. For the purposes of complying with the fugitive emissions monitoring program using Method 21 of appendix A-7 to this part a fugitive emission is defined as an instrument reading of 500 ppmv or greater.

(i) ***Verification that your monitoring equipment meets the requirements specified in Section 6.0 of Method 21 of appendix A-7 to this part.*** For purposes of instrument capability, the fugitive emissions definition shall be 500 ppmv or greater methane using a FID-based instrument. If you wish to use an analyzer other than an FID-based instrument, you must develop a site-specific fugitive emission definition that would be equivalent to 500 ppmv methane using a FID-based instrument (*e.g.,* 10.6 eV PID with a specified isobutylene concentration as the fugitive emission definition would provide equivalent response to your compound of interest).

(ii) ***Procedures for conducting surveys.*** At a minimum, the procedures shall ensure that the surveys comply with the relevant sections of Method 21 of appendix A-7 to this part, including Section 8.3.1.

(iii) ***Procedures for calibration.*** The instrument must be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 to this part. At a minimum, you must also conduct precision tests at the interval specified in Method 21 of appendix A-7 to this part, Section 8.1.2, and a calibration drift assessment at the end of each monitoring day. The calibration drift assessment must be conducted as specified in paragraph (c)(8)(iii)(A) of this section. Corrective action for drift assessments is specified in paragraphs (c)(8)(iii)(B) and (C) of this section.

(A) Check the instrument using the same calibration gas that was used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 to this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. If multiple scales are used, record the instrument reading for each scale used. Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage.

(B) If a calibration drift assessment shows a negative drift of more than 10 percent, then all equipment with instrument readings between the fugitive emission definition multiplied by (100 minus the percent of negative drift) divided by 100 and the fugitive emission definition that was monitored since the last calibration must be re-monitored.

(C) If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the fugitive emission definition and below the fugitive emission definition multiplied by (100 plus the percent of positive drift) divided by 100 monitored since the last calibration may be re-monitored.

(iv) ***Procedures for monitoring yard piping (other than buried yard piping).*** At a minimum, place the probe inlet at the surface of the yard piping and run the probe down the length of the piping. Connection points on the piping must be monitored following the procedures specified in Method 21 of appendix A-7 to this part.

(d) ***Additional elements of fugitive emissions monitoring plan.*** Each fugitive emissions monitoring plan must include the elements specified in paragraphs (d)(1) through (3) of this section, at a minimum, as applicable.

(1) If you are using OGI, your plan must include procedures to ensure that all fugitive emissions components, except buried yard piping and associated components (*e.g.,* connectors), are monitored during each survey. Example procedures include, but are not limited to, a sitemap with an observation path, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components.

(2) If you are using Method 21 of appendix A-7 to this part, your plan must include a list of fugitive emissions components to be monitored and method for determining the location of fugitive emissions components to be monitored in the field (*e.g.,* tagging, identification on a process and instrumentation diagram, etc.). Your fugitive emissions monitoring plan must include the written plan developed for all of the fugitive emissions components designated as difficult-to-monitor in accordance with paragraph (g)(2) of this section, and the written plan for fugitive emissions components designated as unsafe-to-monitor in accordance with paragraph (g)(3) of this section.

(e) ***Monitoring of fugitive emissions components.*** Each fugitive emissions component, except buried yard piping and associated components (*e.g.,* connectors), shall be observed or monitored for fugitive emissions during each monitoring survey.

(f) ***Initial monitoring survey.*** You must conduct initial monitoring surveys according to the requirements specified in paragraphs (f)(1) through (4) of this section.

(1) At single wellhead only sites and small sites, you must conduct an initial monitoring survey using audible, visual, and olfactory (AVO), or any other detection methods (*e.g.,* OGI), within 90 days of the startup of production, for each fugitive emissions components affected facility or by June 6, 2024 whichever date is later.

(2) For multi-wellhead only well sites, well sites or centralized production facilities that contain the major production and processing equipment specified in paragraphs (g)(1)(iv)(A), (B), (C), or (D) of this section, and compressor station sites, you must conduct an initial monitoring survey using OGI or Method 21 of appendix A-7 to this part within 90 days of the startup of production, for each fugitive emissions components affected facility or by June 6, 2024 whichever date is later.

(3) For a modified or reconstructed fugitive emissions components affected facility, the initial monitoring survey must be conducted within 90 days of the startup of production for each fugitive emissions components affected facility after the modification or reconstruction or by June 6, 2024, whichever date is later.

(4) Notwithstanding the deadlines specified in paragraphs (f)(1) through (3) of this section, for each fugitive emissions components affected facility located on the Alaskan North Slope that starts up production between September and March, you must conduct an initial monitoring survey within 6 months of the startup of production for a new well site, within 6 months of the first day of production after a modification of the fugitive emissions components affected facility, or by the following June 30, whichever date is latest.

(g) ***Monitoring frequency.*** A monitoring survey of each fugitive emissions components affected facility must be performed as specified in paragraph (g)(1) of this section, with the exceptions noted in paragraphs (g)(2) through (4) of this section. Monitoring for fugitive emissions components affected facilities located at well sites and centralized production facilities that have wells located onsite must continue at the specified frequencies in paragraphs (g)(1)(i), (ii), (iii), (iv) and (vi) of this section until the well closure requirements of paragraph (l) of this section are completed.

(1) A monitoring survey of the fugitive emissions components affected facilities must be conducted using the methods and at the frequencies specified in paragraphs (g)(1)(i) through (vi) of this section.

(i) A monitoring survey of the fugitive emissions component affected facilities located at single wellhead only well sites must be conducted at least quarterly using AVO, or any other detection method, after the initial survey except as specified in paragraph (g)(1)(vi) of this section. Any indications of fugitive emissions using these methods are considered fugitive emissions that must be repaired in accordance with paragraph (h) of this section.

(ii) A monitoring survey of the fugitive emissions component affected facilities located at small well sites must be conducted at least quarterly using AVO, or any other detection method, after the initial survey except as specified in paragraph (g)(1)(vi) of this section. Any indications of fugitive emissions using these methods are considered fugitive emissions that must be repaired in accordance with paragraph (h) of this section. At small well sites with an uncontrolled storage vessel, a visual inspection of all thief hatches and other openings on the storage vessel that are fugitive emissions components must be conducted in conjunction with the monitoring survey to ensure that they are kept closed and sealed at all times except during times of adding or removing material, inspecting or sampling material, or during required maintenance operations. If evidence of a deviation from this requirement is found, you must take corrective action. At small well sites with a separator, a visual inspection of all separator dump valves to ensure the dump valve is free of debris and not stuck in an open position must be conducted in conjunction with the monitoring survey. Any dump valve not operating as designed must be repaired.

(iii) A monitoring survey of the fugitive emissions components affected facilities located at multi-wellhead only well sites must be conducted in accordance with paragraphs (g)(1)(iii)(A) and (B) of this section, except as specified in paragraph (g)(1)(vi) of this section.

(A) A monitoring survey must be conducted at least quarterly using AVO, or any other detection method, after the initial survey. Any indications of fugitive emissions using these methods are considered fugitive emissions that must be repaired in accordance with paragraph (h) of this section.

(B) A monitoring survey must be conducted at least semiannually using OGI or Method 21 of appendix A-7 to this part after the initial survey. Consecutive semiannual surveys must be conducted at least 4 months apart and no more than 7 months apart.

(iv) A monitoring survey of the fugitive emissions components affected facilities located at well sites or centralized production facilities that contain the major production and processing equipment specified in paragraphs (g)(1)(iv)(A), (B), (C), or (D) must be conducted at the frequencies in paragraphs (g)(1)(iv)(E) and (F) of this section, except as specified in paragraph (g)(1)(vi) of this section.

(A) One or more controlled storage vessels or tank batteries.

(B) One or more control devices.

(C) One or more natural gas-driven process controllers or pumps.

(D) Two or more pieces of major production and processing equipment not specified in paragraphs (g)(1)(iv)(A) through (C) of this section.

(E) A monitoring survey must be conducted at least bimonthly using AVO, or any other detection method, after the initial survey. Any indications of fugitive emissions using these methods are considered fugitive emissions that must be repaired in accordance with paragraph (h) of this section. A visual inspection of all thief hatches and other openings on storage vessels (or tank batteries) that are fugitive emissions components must be conducted in conjunction with the monitoring survey to ensure that they are kept closed and sealed at all times except during times of adding or removing material, inspecting or sampling material, or during required maintenance operations. If evidence of a deviation from this requirement is found, you must take corrective action. A visual inspection must be conducted of all separator dump valves to ensure the dump valve is free of debris and not stuck in an open position must be conducted in conjunction with the monitoring survey. Any dump valve not operating as designed must be repaired.

(F) A monitoring survey must be conducted at least quarterly using OGI or Method 21 of appendix A-7 to this part after the initial survey. Consecutive quarterly monitoring surveys must be conducted at least 60 calendar days apart.

(v) A monitoring survey of the fugitive emissions components affected facility located at a compressor station must be conducted at the frequencies in paragraphs (g)(1)(v)(A) and (B) of this section, except as specified in paragraph (g)(1)(vi) of this section,

(A) A monitoring survey must be conducted at least monthly using AVO, or any other detection method, after the initial survey. Any indications of fugitive emissions using these methods are considered fugitive emissions that must be repaired in accordance with paragraph (h) of this section.

(B) A monitoring survey must be conducted at least quarterly using OGI or Method 21 of appendix A-7 to this part after the initial survey. Consecutive quarterly monitoring surveys must be conducted at least 60 calendar days apart.

(vi) A monitoring survey of the fugitive emissions components affected facility located on the Alaska North Slope must be conducted using OGI of this part or Method 21 of appendix A-7 to this part at least annually. Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart.

(2) If you are using Method 21 of appendix A-7 to this part, fugitive emissions components that cannot be monitored without elevating the monitoring personnel more than 2 meters above the surface may be designated as difficult-to-monitor. Fugitive emissions components that are designated difficult-to-monitor must meet the specifications of paragraphs (g)(2)(i) through (iv) of this section.

(i) A written plan must be developed for all the fugitive emissions components designated difficult-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by paragraphs (b), (c), and (d) of this section.

(ii) The plan must include the identification and location of each fugitive emissions component designated as difficult-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as difficult-to-monitor is difficult-to-monitor.

(iv) The plan must include a schedule for monitoring the difficult-to-monitor fugitive emissions components at least once per calendar year.

(3) If you are using Method 21 of appendix A-7 to this part, fugitive emissions components that cannot be monitored because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey may be designated as unsafe-to-monitor. Fugitive emissions components that are designated unsafe-to-monitor must meet the specifications of paragraphs (g)(3)(i) through (iv) of this section.

(i) A written plan must be developed for all the fugitive emissions components designated unsafe-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by paragraphs (b), (c), and (d) of this section.

(ii) The plan must include the identification and location of each fugitive emissions component designated as unsafe-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as unsafe-to-monitor is unsafe-to-monitor.

(iv) The plan must include a schedule for monitoring the fugitive emissions components designated as unsafe-to-monitor.

(4) The requirements of paragraphs (g)(1)(iv)(F) and (g)(1)(v)(B) of this section are waived during a quarterly monitoring period for any fugitive emissions components affected facility located within an area that has an average calendar month temperature below 0 degrees Fahrenheit for two of three consecutive calendar months of a quarterly monitoring period. The calendar month temperature average for each month within the quarterly monitoring period must be determined using historical monthly average temperatures over the previous three years as reported by a National Oceanic and Atmospheric Administration source or other source approved by the Administrator. The requirements of paragraph (g)(1)(iv) and (v) of this section shall not be waived for two consecutive quarterly monitoring periods.

(h) ***Repairs.*** Each identified source of fugitive emissions shall be repaired in accordance with paragraphs (h)(1) and (2) of this section.

(1) A first attempt at repair shall be made in accordance with paragraphs (h)(1)(i) and (ii) of this section.

(i) A first attempt at repair shall be made no later than 15 calendar days after detection of fugitive emissions that were identified using AVO.

(ii) If you are complying with paragraph (g)(1)(i) through (vi) of this section using OGI or Method 21 of appendix A-7 to this part, a first attempt at repair shall be made no later than 30 calendar days after detection of the fugitive emissions.

(2) Repair shall be completed as soon as practicable, but no later than 15 calendar days after the first attempt at repair as required in paragraph (h)(1)(i) of this section, and 30 calendar days after the first attempt at repair as required in paragraph (h)(1)(ii) of this section.

(3) Delay of repair will be allowed if the conditions in paragraphs (h)(3)(i) or (ii) of this section are met.

(i) If the repair is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown for maintenance, scheduled well shutdown, scheduled well shut-in, after a scheduled vent blowdown, or within 2 years of detecting the fugitive emissions, whichever is earliest. A vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel.

(ii) If the repair requires replacement of a fugitive emissions component or a part thereof, but the replacement cannot be acquired and installed within the repair timelines specified in paragraphs (h)(1) and (2) of this section due to either of the conditions specified in paragraph (h)(3)(ii)(A) or (B) of this section, the repair must be completed in accordance with paragraph (h)(3)(ii)(C) of this section and documented in accordance with § 60.5420b(c)(14)(v)(I).

(A) Valve assembly supplies had been sufficiently stocked but are depleted at the time of the required repair.

(B) A replacement fugitive emissions component or a part thereof requires custom fabrication.

(C) The required replacement must be ordered no later than 10 calendar days after the first attempt at repair. The repair must be completed as soon as practicable, but no later than 30 calendar days after receipt of the replacement component, unless the repair requires a compressor station or well shutdown. If the repair requires a compressor station or well shutdown, the repair must be completed in accordance with the timeframe specified in paragraph (h)(3)(i) of this section.

(4) Each identified source of fugitive emissions must be resurveyed to complete repair according to the requirements of paragraphs (h)(4)(i) through (v) of this section, to ensure that there are no fugitive emissions.

(i) The operator may resurvey the fugitive emissions components to verify repair using either Method 21 of appendix A-7 to this part or OGI, except as specified in paragraph (h)(4)(v) of this section.

(ii) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component, or the component must be tagged during the monitoring survey when the fugitive emissions were initially found for identification purposes and subsequent repair. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (*e.g.,* the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

(iii) Operators that use Method 21 of appendix A-7 to this part to resurvey the repaired fugitive emissions components are subject to the resurvey provisions specified in paragraphs (h)(4)(iii)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppmv above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of Method 21 of appendix A-7 to this part are used.

(B) Operators must use the Method 21 monitoring requirements specified in paragraph (c)(8)(ii) of this section or the alternative screening procedures specified in section 8.3.3 of Method 21 of appendix A-7 to this part.

(iv) Operators that use OGI to resurvey the repaired fugitive emissions components are subject to the resurvey provisions specified in paragraphs (h)(4)(iv)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the OGI instrument shows no indication of visible emissions.

(B) Operators must use the OGI monitoring requirements specified in paragraph (c)(7) of this section.

(v) For fugitive emissions identified using AVO detection methods, the operator may resurvey using those same methods, Method 21 of appendix A-7 to this part, or OGI. For operators that use AVO detection methods, a fugitive emissions component is repaired when there are no indications of fugitive emissions using these methods.

(i) ***Initial compliance.*** You must demonstrate initial compliance with the standards that apply to fugitive emissions components affected facilities as required by § 60.5410b(k).

(j) ***Continuous compliance.*** You must demonstrate continuous compliance with the standards that apply to fugitive emissions components affected facilities as required by § 60.5415b(l).

(k) ***Reporting and recordkeeping.*** You must comply with the reporting requirements as specified in § 60.5420b(b)(1) and (9), and the recordkeeping requirements as specified in § 60.5420b(c)(16).

(l) ***Well closure requirements.*** You must complete the requirements specified in paragraphs (l)(1) through (4) of this section.

(1) You must submit a well closure plan to the Administrator within 30 days of the cessation of production from all wells located at the well site as specified in § 60.5420b(a)(4)(i). The well closure plan must include, at a minimum, the information specified in paragraphs (l)(1)(i) through (iii) of this section.

(i) Description of the steps necessary to close all wells at the well site, including permanent plugging of all wells;

(ii) Description of the financial requirements and disclosure of financial assurance to complete closure; and

(iii) Description of the schedule for completing all activities in the well closure plan.

(2) You must submit a notification as specified in § 60.5420b(a)(4)(ii) of intent to close the well site to the Administrator 60 days before you begin well closure activities.

(3) You must conduct a survey of the well site using OGI, including each closed well, after completing all well closure activities outlined in the well closure plan specified in paragraph (l)(1) of this section. If any emissions are imaged by the OGI instrument, then you must take steps to eliminate those emissions and you must resurvey the source of emissions. You must repeat steps to eliminate

emissions and resurvey the source of emissions until no emissions are imaged by the OGI instrument. You must update the well closure plan specified in paragraph (l)(1) of this section to include the video of the OGI survey demonstrating closure of all wells at the site.

(4) You must maintain the records specified in § 60.5420b(c)(14) and submit the reports specified in § 60.5420b(b)(9).

§ 60.5398b What alternative GHG and VOC standards apply to fugitive emissions components affected facilities and what inspection and monitoring requirements apply to covers and closed vent systems when using an alternative technology?

This section provides alternative GHG and VOC standards for fugitive emissions components affected facilities in § 60.5397b and alternative continuous inspection and monitoring requirements for covers and closed vent systems in § 60.5416b(a)(1)(ii) and (iii), (2)(ii) through (iv), and (3)(iii) and (iv). If you choose to use an alternative standard under this section, you must submit the notification under paragraph (a) of this section. If you choose to demonstrate compliance with the alternative GHG and VOC standards through periodic screening, you are subject to the requirements in paragraph (b) of this section. If you choose to demonstrate compliance through a continuous monitoring system, you are subject to the requirements in paragraph (c) of this section. The technology used for periodic screenings under paragraph (b) of this section or continuous monitoring under paragraph (c) of this section must be approved in accordance with paragraph (d) of this section.

(a) ***Notification.*** If you choose to demonstrate compliance with the alternative GHG and VOC standards in either paragraph (b) or (c) of this section, you must notify the Administrator of adoption of the alternative standards in the first annual report following implementation of the alternative standards, as specified in § 60.5424b(a). Once you have implemented the alternative standards, you must continue to comply with the alternative standards.

(b) ***Periodic Screening.*** You may choose to demonstrate compliance for your fugitive emissions components affected facility and compliance with continuous inspection and monitoring requirements for your covers and closed vent systems through periodic screenings using any methane measurement technology approved in accordance with paragraph (d) of this section. If you choose to demonstrate compliance using periodic screenings, you must comply with the requirements in paragraphs (b)(1) through (5) of this section and comply with the recordkeeping and reporting requirements in § 60.5424b.

(1) You must use one or more alternative test method(s) approved per paragraph (d) of this section to conduct periodic screenings.

(i) The required frequencies for conducting periodic screenings are listed in tables 1 and 2 to this subpart. You must choose the appropriate frequency for conducting periodic screenings based on the minimum aggregate detection threshold of the method used to conduct the periodic screenings. You must also use tables 1 and 2 to this subpart to determine whether you must conduct an annual fugitive emissions survey using OGI, except as provided in paragraph (b)(1)(ii) of this section.

(ii) For well sites, centralized production facilities, and compressor stations subject to quarterly OGI monitoring surveys in § 60.5397b(g)(1)(iv) and/or (v), prior to March 9, 2026, if you use an alternative test method approved per paragraph (d) of this section with a minimum aggregated detection threshold less than or equal to 3 kg/hr, in lieu of conducting periodic screening events at the frequency specified in paragraph (b)(1)(i) of this section, you may conduct periodic screening events quarterly. After March 9, 2026, you must conduct periodic screening events at the frequency specified in paragraph (b)(1)(i) of this section.

(iii) Use of table 1 or 2 to this subpart is based on the required frequency for conducting monitoring surveys in § 60.5397b(g)(1)(i) through (v).

(iv) You may replace one or more individual periodic screening events required by table 1 or 2 to this subpart with an OGI survey. The OGI survey must be conducted according to the requirements outlined in § 60.5397b.

(v) If you use multiple methods to conduct periodic screenings, you must conduct all periodic screenings, regardless of the method used for the individual periodic screening event, at the frequency required for the alternative test method with the highest aggregate detection threshold (*e.g.,* if you use methods with aggregate detection thresholds of 15 kg/hr, your periodic screenings must be conducted monthly). You must also conduct an annual OGI survey if an annual OGI survey is required for the alternative test method with the highest aggregate detection threshold.

(2) You must develop a monitoring plan that covers the collection of fugitive emissions components, covers, and closed vent systems at each site where you will use periodic screenings to demonstrate compliance. You may develop a site-specific monitoring plan, or you may include multiple sites that you own or operate in one plan. At a minimum, the monitoring plan must contain the information specified in paragraphs (b)(2)(i) through (ix) of this section.

(i) Identification of each site that will be monitored through periodic screening, including latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of at least four decimals of a degree using the North American Datum of 1983.

(ii) Identification of the alternative test method(s) approved per paragraph (d) of this section that will be used for periodic screenings and the spatial resolution (*i.e.,* component-level, area-level, or facility-level) of the technology used for each method.

(iii) Identification of and contact information for the entities that will be performing the periodic screenings.

(iv) Required frequency for conducting periodic screenings, based on the criteria outlined in paragraph (b)(1) of this section.

(v) If you are required to conduct an annual OGI survey by paragraph (b)(1)(i) or (iii) of this section or you choose to replace any individual screening event with an OGI survey, your monitoring plan must also include the information required by § 60.5397b(b).

(vi) Procedures for conducting monitoring surveys required by paragraphs (b)(5)(ii)(A), (b)(5)(iii)(A), and (b)(5)(iv)(A) of this section. At a minimum, your monitoring plan must include the information required by § 60.5397b(c)(2), (3), (7), and (8), and (d), as applicable. The provisions of § 60.5397b(d)(3) do not apply for purposes of conducting monitoring surveys required by paragraphs (b)(5)(ii) through (iv) of this section.

(vii) Procedures and timeframes for identifying and repairing fugitive emissions components, covers, and closed vent systems from which emissions are detected.

(viii) Procedures and timeframes for verifying repairs for fugitive emissions components, covers, and closed vent systems.

(ix) Records that will be kept and the length of time records will be kept.

(3) You must conduct the initial screening of your site according to the timeframes specified in (b)(3)(i) through (v) of this section.

(i) Within 90 days of the startup of production for each fugitive emissions components affected facility and storage vessel affected facility located at a new well site or centralized production facility.

(ii) Within 90 days of the startup of a new compressor station for each fugitive emissions components affected facility and storage vessel affected facility located at a new compressor station.

(iii) Within 90 days of the startup of production after modification for each modified fugitive emissions components affected facility and storage vessel affected facility at a well site or centralized production facility.

(iv) Within 90 days of modification for each modified fugitive emissions components affected facility and storage vessel affected facility at a compressor station.

(v) No later than the final date by which the next monitoring survey required by § 60.5397b(g)(1)(i) through (v) would have been required to be conducted if you were previously complying with the requirements in § 60.5397b and § 60.5416b(a)(1)(ii) and (iii), (2)(ii) through (iv), and (3)(iii) and (iv).

(4) If you are required to conduct an annual OGI survey by paragraph (b)(1)(i) or (iii) of this section, you must conduct OGI surveys according to the schedule in paragraphs (b)(4)(i) through (iv) of this section.

(i) You must conduct the initial OGI survey no later than 12 calendar months after conducting the initial screening event in paragraph (b)(3) of this section.

(ii) Each subsequent OGI survey must be conducted no later than 12 calendar months after the previous OGI survey was conducted. Each identified source of fugitive emissions during the OGI survey shall be repaired in accordance with § 60.5397b(h).

(iii) If you replace a periodic screening event with an OGI survey or you are required to conduct a monitoring survey in accordance with paragraph (b)(5)(ii)(A) of this section prior to the date that your next OGI survey under paragraph (b)(4)(ii) of this section is due, the OGI survey conducted in lieu of the periodic screening event or the monitoring survey under paragraph (b)(5)(ii)(A) of this section can be used to fulfill the requirements of paragraph (b)(4)(ii) of this section. The next OGI survey is required to be conducted no later than 12 calendar months after the date of the survey conducted under paragraph (b)(1)(iv) or (b)(5)(ii)(A) of this section.

(iv) You cannot use a monitoring survey conducted under paragraph (b)(5)(iii)(A) or (b)(5)(iv)(A) of this section to fulfill the requirements of paragraph (b)(4)(ii) of this section unless the monitoring survey included all fugitive emission components at the site.

(5) You must investigate confirmed detections of emissions from periodic screening events and repair each identified source of emissions in accordance with paragraphs (b)(5)(i) through (vii) of this section.

(i) You must receive the results of the periodic screening no later than 5 calendar days after the screening event occurs.

(ii) If you use an alternative test method with a facility-level spatial resolution to conduct a periodic screening event and the results of the periodic screening event indicate a confirmed detection of emissions from an affected facility, you must take the actions listed in paragraphs (b)(5)(ii)(A) through (C) of this section.

(A) You must conduct a monitoring survey of the entire fugitive emissions components affected facility following the procedures in your monitoring plan. During the survey, you must observe each fugitive emissions component for fugitive emissions.

(B) You must inspect all covers and closed vent system(s) with OGI or Method 21 to appendix A-7 to this part in accordance with the requirements in § 60.5416b(b)(1) through (4), as applicable.

(C) You must conduct a visual inspection of all covers and closed vent systems to identify if there are any defects, as defined in § 60.5416b(a)(1)(ii), (a)(2)(iii), or (a)(3)(i), as applicable.

(iii) If you use an alternative test method with an area-level spatial resolution to conduct a periodic screening event and the results of the periodic screening event indicate a confirmed detection of emissions from an affected facility, you must take the actions listed in paragraphs (b)(5)(iii)(A) and (B) of this section, as applicable.

(A) You must conduct a monitoring survey of all your fugitive emissions components located within a 4-meter radius of the location of the periodic screening's confirmed detection. You must follow the procedures in your monitoring plan when conducting the survey.

(B) If the confirmed detection occurred in the portion of a site that contains a storage vessel or a closed vent system, you must inspect all covers and all closed vent systems that are connected to all storage vessels and closed vent systems that are within a 2-meter radius of the location of the periodic screening's confirmed detection (*i.e.,* you must inspect the whole system that is connected to the portion of the system in the radius of the detected event, not just the portion of the system that falls within the radius of the detected event).

(*1*) You must inspect the cover(s) and closed vent system(s) with OGI or Method 21 to appendix A-7 to this part in accordance with the requirements in § 60.5416b(b)(1) through (4), as applicable.

(*2*) You must conduct a visual inspection of the closed vent system(s) and cover(s) to identify if there are any defects, as defined in § 60.5416b(a)(1)(ii), (a)(2)(iii), or (a)(3)(i), as applicable.

(iv) If you use an alternative test method with a component-level spatial resolution to conduct a periodic screening event and the results of the periodic screening event indicate a confirmed detection of emissions from an affected facility, you must take the actions listed in paragraphs (b)(5)(iv)(A) and (B) of this section, as applicable.

(A) You must conduct a monitoring survey of the all the fugitive emissions components located within a 1-meter radius of the location of the periodic screening's confirmed detection. You must follow the procedures in your monitoring plan when conducting the survey.

(B) If the confirmed detection occurred in the portion of a site that contains a storage vessel or a closed vent system, you must inspect all covers and all closed vent systems that are connected to all storage vessels and closed vent systems that are within a 0.5-meter radius of the location of the periodic screening's confirmed detection (*i.e.,* you must inspect the whole system that is connected to the portion of the system in the radius of the detected event, not just the portion of the system that falls within the radius of the detected event).

(*1*) You must inspect the cover(s) and closed vent system(s) with OGI or Method 21 to appendix A-7 to this part in accordance with the requirements in § 60.5416b(b)(1) through (4), as applicable.

(*2*) You must conduct a visual inspection of the closed vent system(s) and cover(s) to identify if there are any defects, as defined in § 60.5416b(a)(1)(ii), (a)(2)(iii), or (a)(3)(i), as applicable.

(v) You must repair all sources of fugitive emissions in accordance with § 60.5397b(h) and all emissions or defects of covers and closed vent systems in accordance with § 60.5416b(b)(5), except as specified in this paragraph (b)(5)(v). Except as allowed by § 60.5397b(h)(3) and § 60.5416b(b)(6), all repairs must be completed, including the resurvey verifying the repair, within 30 days of receiving the results of the periodic screening in paragraph (b)(5)(i) of this section.

(vi) If the results of the periodic screening event in paragraph (b)(5)(i) of this section indicate a confirmed detection at an affected facility, and the ground-based monitoring survey and inspections required by paragraphs (b)(5)(ii) through (iv) of this section demonstrate the confirmed detection was caused by a failure of a control device used to demonstrate continuous compliance under this subpart, you must initiate an investigative analysis to determine the underlying primary and other contributing cause(s) of such failure within 24 hours of receiving the results of the monitoring survey and/or inspection. As part of the investigation, you must determine if the control device is operating in compliance with the applicable requirements of § 60.5415b and § 60.5417b, and if not, what actions are necessary to bring the control device into compliance with those requirements as soon as possible and prevent future failures of the control device from the same underlying cause(s).

(vii) If the results of the inspections required in paragraphs (b)(5)(ii) through (iv) of this section indicate that there is an emission or defect in your cover or closed vent system, you must perform an investigative analysis to determine the underlying primary and other contributing cause(s) of emissions from your cover or closed vent system within 5 days of completing the inspection required by paragraphs (b)(5)(ii) through (iv) of this section. The investigative analysis must include a determination as to whether the system was operated outside of the engineering design analysis and whether updates are necessary for the cover or closed vent system to prevent future emissions from the cover and closed vent system.

(6) You must maintain records as specified in § 60.5420b(c)(4) through (7), (14), and (15), and § 60.5424b(c).

(7) You must submit reports as specified in § 60.5424b.

(c) ***Continuous monitoring.*** You may choose to demonstrate compliance for your fugitive emissions components affected facility and compliance with continuous inspection and monitoring requirements for your covers and closed vent systems through continuous monitoring using a technology approved in accordance with paragraph (d) of this section. If you choose to demonstrate compliance using continuous monitoring, you must comply and develop a monitoring plan consistent with the requirements in paragraphs (c)(1) through (9) of this section and comply with the recordkeeping and reporting requirements in § 60.5424b.

(1) For the purpose of this section, continuous monitoring means the ability of a methane monitoring system to determine and record a valid methane mass emissions rate or equivalent of affected facilities at least once for every 12-hour block.

(i) The detection threshold of the system must be such that it can detect at least 0.40 kg/hr (0.88 lb/hr) of methane.

(ii) The health of the devices used within the continuous monitoring system must be confirmed for power and function at least twice every six-hour block.

(iii) The continuous monitoring system must transmit all applicable valid data at least once every 24-hours. The continuous monitoring system must transmit all valid data collected, including health checks required in paragraph (c)(1)(ii) of this section.

(iv) The continuous monitoring system must continuously collect data as specified in paragraph (c)(1) of this section, except as specified in paragraphs (c)(1)(iv)(A) through (D) of this section:

(A) The rolling 12-month average operational downtime of the continuous monitoring system must be less than or equal to 10 percent.

(B) Operational downtime of the continuous monitoring system is defined as a period of time for which any monitor fails to collect or transmit data as specified in paragraph (c)(1) of this section or any monitor is out-of-control as specified in paragraph (c)(1)(iv)(C) of this section.

(C) A monitor is out-of-control if it fails ongoing quality assurance checks, as specified in the alternative test method approved under paragraph (d) of this section, or if the monitor output is outside of range. The beginning of the out-of-control period is defined as the time of the failure of the quality assurance check. The end of the out-of-control period is defined as the time when either the monitor passes a subsequent quality assurance check, or a new monitor is installed. The out-of-control period for a monitor outside of range starts at the time when the monitor first reads outside of range and ends when the monitor reads within range again.

(D) The downtime for the continuous monitoring system must be calculated each calendar month. Once 12 months of data are available, at the end of each calendar month, you must calculate the 12-month average by averaging that month with the previous 11 calendar months. You must determine the rolling 12-month average by recalculating the 12-month average at the end of each month.

(2) You must develop a monitoring plan that covers the collection of fugitive emissions components, covers, and closed vent systems for each site where continuous monitoring will be used to demonstrate compliance. At a minimum, the monitoring plan must contain the information specified in paragraphs (c)(2)(i) through (xii) of this section.

(i) Identification of each site to be monitored through continuous monitoring, including latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of at least four decimals of a degree using the North American Datum of 1983.

(ii) Identification of the alternative test method(s) approved under paragraph (d) of this section used for the continuous monitoring, including the detection principle; the manufacturer, make, and model; instrument manual, if applicable; and the manufacturer's recommended maintenance schedule.

(iii) If the continuous monitoring system is administered through a third-party provider, contact information where the provider can be reached 24 hours a day.

(iv) Number and location of monitors. If the continuous monitoring system uses open path technology, you must identify the location of any reflectors used. These locations should be identified by latitude and longitude coordinates in decimal degrees to an accuracy and precision of at least five decimals of a degree using the North American Datum of 1983.

(v) Discussion of system calibration requirements, including but not limited to, the calibration procedures and calibration schedule for the detection systems and meteorology systems.

(vi) Identification of critical components and infrastructure (*e.g.,* power, data systems) and procedures for their repairs.

(vii) Procedures for out-of-control periods.

(viii) Procedures for establishing baseline emissions, including the identification of any sources with methane emissions not subject to this subpart. The procedures for establishing the baseline emissions must account for variability in the operation of the site. Operation of the site during the development of the baseline emissions must represent the site's expected annual production or throughput.

(ix) Procedures for determining when a fugitive emissions event is detected by the continuous monitoring technology.

(x) Procedures and timeframes for identifying and repairing fugitive emissions components, covers, and closed vent systems from which emissions are detected.

(xi) Procedures and timeframes for verifying repairs for fugitive emissions components, covers, and closed vent systems.

(xii) Records that will be kept and the length of time records will be kept.

(3) You must install and begin conducting monitoring with your continuous monitoring system according to the timeframes specified in paragraphs (c)(3)(i) through (v) of this section.

(i) Within 120 days of the startup of production for each fugitive emissions components affected facility and storage vessel affected facility located at a new well site or centralized production facility.

(ii) Within 120 days of the startup of a new compressor station for each fugitive emissions components affected facility and storage vessel affected facility located at a new compressor station.

(iii) Within 120 days of the startup of production after modification for each modified fugitive emissions components affected facility and storage vessel affected facility at a well site or centralized production facility.

(iv) Within 120 days of modification for each modified fugitive emissions components affected facility and storage vessel affected facility at a compressor station.

(v) No later than the final date by which the next monitoring survey required by § 60.5397b(g)(1)(i) through (v) would have been required to be conducted if you were previously complying with the requirements in § 60.5397b and § 60.5416b(a)(1)(ii) and (iii), (2)(ii) through (iv), and (3)(iii) and (iv).

(4) You are subject to the following action-levels as specified in paragraphs (c)(4)(i) and (ii) of this section for any affected facilities located at a well site, centralized production facility, or compressor station.

(i) For affected facilities located at a wellhead only well site, the action levels are as follows:

(A) The 90-day rolling average action-level is 1.2 kg/hr (2.6 lb/hr) of methane over the site-specific baseline emissions.

(B) The 7-day rolling average action level is 15 kg/hr (34 lb/hr) of methane over site-specific baseline emissions.

(ii) For affected facilities located at well sites with major production and processing equipment (including small well sites), centralized production facilities, and compressor stations, the action levels are as follows:

(A) The 90-day rolling average action-level is 1.6 kg/hr (3.6 lb/hr) of methane over the site-specific baseline emissions.

(B) The 7-day rolling average action level is 21 kg/hr (46 lb/hr) of methane over the site-specific baseline emissions.

(5) You must establish site-specific baseline emissions upon initial installation and activation of a continuous monitoring system. You must establish the baseline emissions under the conditions outlined in paragraphs (c)(5)(i) through (iii) of this section. You must determine the baseline emission rates according to paragraphs (c)(5)(iv) and (v) of this section. The baseline must be established initially and any time there is a major change to the processing equipment at a well site (including small well sites), centralized production facility, or compressor station.

(i) Inspect all fugitive emissions components according to the requirements in § 60.5397b and covers and closed vent systems according to the requirements in § 60.5416b. This includes all fugitive emissions components, covers, and closed vent systems, regardless of whether they are regulated by this subpart. Repairs of any fugitive emissions, leaks, or defects found during the inspection must be completed prior to beginning the period in paragraph (c)(5)(iii) of this section.

(ii) Verify control devices (*e.g.,* flares) on all affected sources are operating in compliance with the applicable requirements of § 60.5415b and § 60.5417b. You must ensure that all control devices are operating in compliance with the applicable regulations prior to beginning the period in paragraph (b)(5)(iii) of this section. Verify that all other methane emission sources (*e.g.,* reciprocating engines) located at the site are operating consistent with any applicable regulations. You must ensure that these sources are operating in compliance with the applicable regulations prior to beginning the period in paragraph (b)(5)(iii) of this section.

(iii) Using the alternative test method approved under paragraph (d) of this section, record the site-level emission rate from your continuous monitoring system for 30 operating days. You must minimize any activities that are not normal, day-to-day activities during this 30 operating day period. Document any maintenance activities and the period (including the start date and time and end date and time) such activities occurred during the 30 operating day period.

(iv) Determine the site-specific baseline by calculating the mean emission rate (kg/hr of methane) for the 30 operating day period, less any time periods when maintenance activities were conducted.

(v) The site-specific baseline emission rate must be no more than 10 times the applicable 90-day action-level defined in paragraphs (c)(4)(i) and (ii) of this section.

(6) Calculate the emission rate from your site according to paragraphs (c)(6)(i) through (iii) of this section. Compare the emission rate calculated in this paragraph (c)(6) to the appropriate action levels in paragraph (c)(4) of this section to determine whether you have exceeded an action level.

(i) Each calendar day, calculate the daily average mass emission rate in kg/hr of methane from your continuous monitoring system.

(ii) Once the system has been operating for 7 calendar days, at the end of each calendar day calculate the 7-day average mass emission rate by averaging the mass emission rate from that day with the mass emission rate from the previous 6 calendar days. Subtract the site-specific baseline mass emission rate from the 7-day average mass emission rate when comparing the mass emission rate to the applicable action level. Determine the 7-day rolling average by recalculating the 7-day average each calendar day, less the site-specific baseline.

(iii) Once the system has been operating for 90 calendar days, at the end of each calendar day calculate the 90-day average mass emission rate by averaging the mass emission rate from that day with the mass emission rate from the previous 89 calendar days. Subtract the site-specific baseline emission rate from the 90-day average mass emission rate when comparing the mass emission rate to the applicable action level. Determine the 90-day rolling average by recalculating the 90-day average each calendar day, less the site-specific baseline.

(7) Within 5 days of determining that either of your action levels in paragraph (c)(4) of this section has been exceeded, you must initiate an investigative analysis to determine the underlying primary and contributing cause(s) of such exceedance and actions to be taken to reduce the mass emission rate below the applicable action level.

(i) You must complete the investigative analysis and take initial steps to bring the mass emission rate below the action level no later than 5 days after determining there is an exceedance of the action level in paragraph (c)(4)(i)(B) or (c)(4)(ii)(B) of this section.

(ii) You must complete the investigative analysis and take initial steps to bring the mass emission rate below the action level no later than 30 days after determining there is an exceedance of the action level in paragraph (c)(4)(i)(A) or (c)(4)(ii)(A) of this section.

(8) You must develop a mass emission rate reduction plan if you meet any of the criteria in paragraphs (c)(8)(i) through (iii) of this section. The plan must describe the action(s) completed to date to reduce the mass emission rate below the action level, additional measures that you propose to employ to reduce methane emissions below the action level, and a schedule for completion of these measures. You must submit the plan to the Administrator within 60 days of initially determining there is an exceedance of an action level in paragraph (c)(4) of this section.

(i) If, upon completion of the initial actions required under paragraph (c)(7) of this section, the average mass emission rate for the following 30-day period is not below the applicable action level in paragraph (c)(4)(i)(A) or (c)(4)(ii)(A) of this section. The beginning of the 30-day period starts on the calendar day following completion of the initial actions in paragraph (c)(7) of this section.

(ii) If, upon completion of the initial actions required under paragraph (c)(6) of this section, the average mass emission rate for the following 24-hour period is not below the applicable action level in paragraph (c)(4)(i)(B) or (c)(4)(ii)(B) of this section. The average mass emission rate will be the mass emission rate calculated according to paragraph (c)(6)(i) of this section for the calendar day following completion of the initial corrective actions in paragraph (c)(7) of this section.

(iii) All actions needed to reduce the average mass emission rate below the action level require more than 30 days to implement.

(9) You must maintain the records as specified in § 60.5420b(c)(4) through (c)(7), (c)(14) and (c)(15), and § 60.5424b(e). You must submit the reports as specified in § 60.5420b(b)(1), and (b)(4) through (10) and § 60.5424b.

(d) ***Alternative Test Method for Methane Detection Technology.*** Any alternative test method for methane detection technology used to meet the requirements specified in paragraphs (b) or (c) of this section or § 60.5371b must be approved by the Administrator as specified in this paragraph (d). Approval of an alternative test method for methane detection technology will include consideration of the combination of the measurement technology and the standard protocol for its operation. Any entity meeting the requirements in paragraph (d)(2) of this section may submit a request for an alternative test method for methane detection technology. At a minimum, the request must follow the requirements outlined in paragraph (d)(3) of this section. Approved alternative test methods for methane detection technology that are broadly applicable will be posted on the EPA's Emission Measurement Center web page (*https://www.epa.gov/emc/oil-and-gas-alternative-test-methods*). Any owner or operator that meets the specific applicability for the alternative test method, as outlined in the alternative test method for methane detection technology, may use the alternative test method to comply with the requirements of paragraph (b) or (c) of this section, as applicable, in lieu of the requirements for fugitive emissions components affected facilities in § 60.5397b and covers and closed vent systems in § 60.5416b(a)(1)(ii) and (iii), (a)(2)(ii) through (iv), and (a)(3)(iii) and (iv). Certified third-party notifiers may use the alternative test method to identify super-emitter events in § 60.5371b(b)(1)(ii).

(1) A request for an alternative test method for methane detection technology, along with the required supporting information, must be submitted to the EPA through the alternative methane detection technology portal at *https://www.epa.gov/emc/oil-and-gas-alternative-test-methods*. The EPA may make all the information submitted through the portal available to the public without further notice to you. Do not use the portal to submit information you claim as confidential business information (CBI). If you wish to assert a CBI claim for some of the information in your submittal, submit the portion of the information claimed as CBI to the OAQPS CBI office. Clearly mark 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 the portal cannot later be claimed CBI. 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 should include clear CBI markings and be flagged to the attention of the Leader, Measurement Technology 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. 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 Technology Group Leader, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, North Carolina 27711. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(i) The Administrator will complete an initial review for completeness within 90 days of receipt and notify the submitter of the results of the review.

(ii) If the entity submitting the request does not meet the requirements in paragraph (d)(2) of this section or the request does not contain the information in paragraph (d)(3) of this section, the submitter will be notified. The submitter may choose to revise the information and submit a new request for an alternative test method.

(iii) Within 270 days of receipt of an alternative test method request that was determined to be complete, the Administrator will determine whether the requested alternative test method is adequate for indicating compliance with the requirements for monitoring fugitive emissions components affected facilities in § 60.5397b and continuous inspection and monitoring of covers and closed vent systems in § 60.5416b and/or for identifying super-emitter events in § 60.5371b. The Administrator will issue either an approval or disapproval in writing to the submitter. Approvals may be considered site-specific or more broadly applicable. Broadly applicable alternative test methods and approval letters will be posted at *https://www.epa.gov/emc/oil-and-gas-approved-alternative-test-methods-approvals.* If the Administrator fails to provide the submitter a decision on approval or disapproval within 270 days, the alternative test method will be given conditional approval status and posted on this same web page. If the Administrator finds any deficiencies in the request and disapproves the request in writing, the owner or operator may choose to revise the information and submit a new request for an alternative test method.

(iv) If the Administrator finds reasonable grounds to dispute the results obtained by any alternative test method for the purposes of demonstrating compliance with a relevant standard, the Administrator may require you to demonstrate compliance according to § 60.5397b for fugitive emissions components affected facilities and § 60.5416b for covers and closed vent systems.

(2) Any entity may submit an alternative test method for consideration, so long as you meet the requirements in paragraphs (d)(2)(i) through (iv) of this section.

(i) An entity is limited to any individual or organization located in or that has representation in the United States.

(ii) If an entity is not considered an owner or operator of an affected facility regulated under this subpart or subpart OOOOa of this part or is not the owner or operator of a designated facility regulated under subpart OOOOc of this part, the provisions of paragraphs (d)(2)(ii)(A) and (B) of this section apply.

(A) The entity must directly represent the provider of the measurement system using advanced methane detection technology.

(B) The measurement system must have been applied to methane measurements or monitoring in the oil and gas sector either domestically or internationally.

(iii) The underlying technology or technologies must be readily available for use, meaning that the measurement system using these technologies has either been:

(A) Sold, leased, or licensed, or offered for sale, lease, or license to the general public or;

(B) Developed by an owner or operator for internal use and/or use by external partners.

(iv) The entity must be able to provide and submit to the Administrator the information required in paragraph (d)(3) of this section.

(3) The request must contain the information specified in paragraphs (d)(3)(i) through (vii) of this section.

(i) The submitter's name, mailing address, phone number and email address.

(ii) The desired applicability of the technology (*i.e.,* site-specific, basin-specific, or broadly applicable across the sector, super-emitter detection).

(iii) Description of the measurement technology, including the physical components, the scientific theory, and the known limitations. At a minimum, this description must contain the information in paragraphs (d)(3)(iii)(A) through (D) of this section.

(A) Description of scientific theory and appropriate references outlining the underlying g technology (*e.g.,* reference material, literature review).

(B) Description of the physical instrumentation.

(C) Type of measurement and application (*e.g.,* remote or in-situ measurements, mobile, airborne).

(D) Known limitation of the technology, including application limitations and weather limitations.

(iv) Description of how the measurement technology is converted to a methane mass emission rate (*i.e.,* kg/hr of methane) or equivalent. At a minimum this description must contain the information in paragraphs (d)(3)(iv)(A) through (F) of this section.

(A) Detailed workflow and description covering all steps and processes from measurement technology signal output to final, validated mass emission rate or equivalent. These workflows must cover the material in paragraph (d)(3)(v) of this section and put all technical components into context. The workflow must also cover the technology from data collection to generation of the final product and identify any raw data processing procedures; identification of whether processing steps are manual or automated, and when and what quality assurance checks are made to the data, including raw data, processed data, and output data.

(B) Description of how any meteorological data used are collected or sourced, including a description how the data are used.

(C) Description of any model(s) (*e.g.,* AERMOD) used, including how inputs are determined or derived.

(D) All calculations used, including the defined variables for any of these calculations and a description of their purposes.

(E) Descriptions of a-priori methods and datasets used, including source and version numbers when applicable.

(F) Description of algorithms/machine learning procedures used in the data processing, if applicable.

(v) Description of how all data collected and generated by the measurement system are handled and stored. At a minimum this description must contain the information in paragraphs (d)(3)(v)(A) through (C) of this section.

(A) How the data, including metadata, are collected, maintained, and stored.

(B) A description of how raw data streams are processed and manipulated, including how the resultant data processing is documented and how version controlled is maintained.

(C) A description of what data streams are provided to the end-user of the data and how the data are delivered to the end-user.

(vi) Supporting information verifying that the technology meets the aggregate detection threshold(s) defined in paragraphs (b) and/or (c) of this section or in § 60.5371b, including supporting data to demonstrate the aggregate detection threshold of the measurement technology as applied in the field and if applicable, how probability of detection is determined. For the purpose of this subpart the average aggregate detection threshold is the average of all site-level detection thresholds from a single deployment (*e.g.,* a singular flight that surveys multiple well sites, centralized production facility, and/or compressor stations) of a technology, unless this technology is to be applied to § 60.5371b. When the technology is applied to § 60.5371b, then the aggregate detection threshold is the average of all site-level detection thresholds from a single deployment in the same basin and field. At a minimum, you provide the information identified in paragraphs (d)(3)(vi)(A) through (D) of this section.

(A) Published reports (*e.g.,* scientific papers) produced by either the submitting entity or an outside entity evaluating the submitted measurement technology that has been independently evaluated. The published reports must identify either a site-level or aggregate detection threshold and be accompanied with sufficient supporting data to evaluate whether the performance metrics of the alternative testing procedures in paragraph (d)(3)(vi)(C) of this section are adequate and the data was collected consistent with those alternative testing procedures. The supporting data may be included in the published report or may be submitted separately.

(B) Standard operating procedures including safety considerations, measurement limitations, personnel qualification/responsibilities, equipment and supplies, data and record management, and quality assurance/quality control (*i.e.,* initial and ongoing calibration procedures, data quality indicators, and data quality objectives).

(C) Detailed description of the alternative testing procedure(s), preferably in the format described in Guideline Document 45 on the Emission Measurement Center's website (available at *https://www.epa.gov/sites/default/files/2020-08/documents/gd-045.pdf*). The detailed description must address all key elements of the requested method(s) and must include objectives to ensure the detection threshold(s) required in paragraph (d)(3)(vi) of this section are maintained, including procedures for verifying the detection threshold and/or or probability of detection is maintained under field conditions.

(D) Any documents provided to end-users of the data generated by the measurement system, including but not limited to client products, manuals, and frequently asked questions documents.

(vii) If the technology will be used to monitor the collection of fugitive emissions components, covers, and closed vent systems at a well site, centralized production facility, or compressor station, you must submit supporting information verifying the spatial resolution of technology, as defined in paragraphs (d)(3)(vii)(A) through (C) of this section. This supporting information must be in the form of a published reports (*e.g.,* scientific papers) produced by either the submitting entity or an outside entity evaluating the submitted measurement technology that has been independently evaluated. The report must include sufficient supporting data to evaluate whether the performance metrics of the alternative testing procedures in paragraph (d)(3)(vi)(C) of this section are adequate and the data was collected consistent with those alternative testing procedures.

(A) Facility-level spatial resolution means a technology with the ability to identify emissions within the boundary of a well site, centralized production facility, or compressor station.

(B) Area-level spatial resolution means a technology with the ability to identify emissions within a radius of 2 meters of the emission source.

(C) Component-level spatial resolution means a technology with the ability to identify emissions within a radius of 0.5 meter of the emission source.

§ 60.5399b What are the alternative means of emission limitations for GHG and VOC emissions from well completions, liquids unloading operations, centrifugal compressors, reciprocating compressors, fugitive emissions components, and process unit equipment affected facilities; and what are the alternative fugitive emissions standards based on State, local, and Tribal programs?

This section provides procedures for the submittal and approval of alternative means of emission limitation for GHG and VOC based on work practices for well completions, liquids unloading operations, centrifugal compressors, reciprocating compressors, fugitive emissions components and process unit equipment affected facilities. This section also provides procedures for the submittal and approval of alternative fugitive emissions standards based on programs under state, local, or Tribal authorities for the fugitive emissions components affected facility. Paragraphs (a) through (d) of this section outline the procedure for submittal and approval of alternative means of emission limitation for methane and VOC. Paragraphs (e) through (i) of this section outline the procedure for submittal and approval of alternative fugitive emissions standards. The requirements for a monitoring plan specified in § 60.5397b(c) and (d) apply to the alternative fugitive emissions standards in this section.

(a) ***Alternative means of emission limitation.*** If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under § 60.5375b, § 60.5376b, § 60.5380b, § 60.5385b, § 60.5397b, § 60.5400b, or § 60.5401b, the Administrator will publish, in the Federal Register, a notice permitting the use of that alternative means for the purpose of compliance with § 60.5375b, § 60.5376b, § 60.5380b, § 60.5385b, § 60.5397b, § 60.5400b, or § 60.5401b. The authority to approve an alternative means of emission limitation is retained by the Administrator and shall not be delegated to States under section 111(c) of the CAA.

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

(c) ***Evaluation guidelines.*** Determination of equivalence to the design, equipment, work practice, or operational requirements of this section will be evaluated by the following guidelines:

(1) The applicant must provide information that is sufficient for demonstrating the alternative means of emission limitation achieves emission reductions that are at least equivalent to the emission reductions that would be achieved by complying with the relevant standards. At a minimum, the application must include the following information:

(i) Details of the specific equipment or components that would be included in the alternative.

(ii) A description of the alternative work practice, including, as appropriate, the monitoring method, monitoring instrument or measurement technology, and the data quality indicators for precision and bias.

(iii) The method detection limit of the technology, technique, or process and a description of the procedures used to determine the method detection limit. At a minimum, the applicant must collect, verify, and submit field data encompassing seasonal variations to support the determination of the method detection limit. The field data may be supplemented with modeling analyses, controlled test site data, or other documentation.

(iv) Any initial and ongoing quality assurance/quality control measures necessary for maintaining the technology, technique, or process, and the timeframes for conducting such measures.

(v) Frequency of measurements. For continuous monitoring techniques, the minimum data availability.

(vi) Any restrictions for using the technology, technique, or process.

(vii) Initial and continuous compliance procedures, including recordkeeping and reporting, if the compliance procedures are different than those specified in this subpart.

(2) For each technology, technique, or process for which a determination of equivalency is requested, the application must provide a demonstration that the emission reduction achieved by the alternative means of emission limitation is at least equivalent to the emission reduction that would be achieved by complying with the relevant standards in this subpart.

(d) ***Approval of alternative means of emission limitation.*** Any alternative means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the CAA.

(e) ***Alternative fugitive emissions standards.*** If, in the Administrator's judgment, an alternative fugitive emissions standard will achieve a reduction in methane and VOC emissions at least equivalent to the reductions achieved under § 60.5397b, the Administrator will publish, in the Federal Register , a notice permitting use of the alternative fugitive emissions standard for the purpose of compliance with § 60.5397b. The authority to approve alternative fugitive emissions standards is retained by the Administrator and shall not be delegated to States under section 111(c) of the CAA.

(f) ***Notice.*** Any notice under paragraph (e) of this section will be published only after notice and an opportunity for public hearing.

(g) ***Evaluation guidelines.*** Determination of alternative fugitive emissions standards to the design, equipment, work practice, or operational requirements of § 60.5397b will be evaluated by the following guidelines:

(1) The monitoring instrument, including the monitoring procedure;

(2) The monitoring frequency;

(3) The fugitive emissions definition;

(4) The repair requirements; and

(5) The recordkeeping and reporting requirements.

(h) ***Approval of alternative fugitive emissions standard.*** Any alternative fugitive emissions standard approved under this section shall:

(1) Constitute a required design, equipment, work practice, or operational standard within the meaning of section 111(h)(1) of the CAA; and

(2) Be made available for use by any owner or operator in meeting the relevant standards and requirements established for affected facilities under § 60.5397b.

(i) ***Notification.***

(1) An owner or operator must notify the Administrator of adoption of the alternative fugitive emissions standards within the first annual report following implementation of the alternative fugitive emissions standard, as specified in § 60.5420b(a)(3).

(2) An owner or operator implementing one of the alternative fugitive emissions standards must submit the reports specified in § 60.5420b(b)(9)(iii). An owner or operator must also maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

§ 60.5400b What GHG and VOC standards apply to process unit equipment affected facilities?

This section applies to process unit equipment affected facilities located at an onshore natural gas processing plant. You must comply with the requirements of paragraphs (a) through (l) of this section to reduce methane and VOC emissions from equipment leaks, except as provided in § 60.5402b. As an alternative to the standards in this section, you may comply with the requirements in § 60.5401b.

(a) ***General standards.*** You must comply with the requirements in paragraphs (b) through (d) of this section for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor or light liquid service, and connector in gas/vapor or light liquid service, as applicable. You must comply with the requirements in paragraph (e) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (f) of this section for each closed vent system and control device used to comply with equipment leak provisions in this section. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must make repairs as specified in paragraph (h) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (i) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (j) of this section. You must perform the reporting as specified in paragraph (k) of this section. You must perform the recordkeeping as required in paragraph (l) of this section.

(1) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of § 60.5399b.

(2) Each piece of equipment is presumed to have the potential to emit methane or VOC unless an owner or operator demonstrates that the piece of equipment does not have the potential to emit methane or VOC. For a piece of equipment to be considered not to have the potential to emit methane or VOC, the methane and VOC content of a gaseous stream must be below detection limits using Method 18 of appendix A-6 to this part. Alternatively, if the piece of equipment is in wet gas service, you may choose to determine the methane and VOC content of the stream is below the detection limit of the methods described in ASTM E168-16(R2023), E169-16(R2022), or E260-96 (all incorporated by reference, see § 60.17).

(b) ***Monitoring surveys.*** You must monitor for leaks using OGI in accordance with appendix K of this part, unless otherwise specified in paragraphs (c) or (d) of this section.

(1) Monitoring surveys must be conducted bimonthly.

(2) Any emissions observed using OGI are defined as a leak.

(c) ***Additional requirements for pumps in light liquid service.*** In addition to the requirements in paragraph (b), you must conduct weekly visual inspections of all pumps in light liquid service for indications of liquids dripping from the pump seal, except as specified in paragraphs (c)(3) and (4) of this section. If there are indications of liquids dripping from the pump seal, you must follow the procedure specified in either paragraph (c)(1) or (2) of this section.

(1) Monitor the pump within 5 calendar days using the methods specified in § 60.5403b. A leak is detected if any emissions are observed using OGI or if an instrument reading of 2,000 ppmv or greater is provided using Method 21 of appendix A-7 to this part.

(2) Designate the visual indications of liquids dripping as a leak and repair the leak as specified in paragraph (h) of this section.

(3) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process, fuel gas system, or a control device that complies with the requirements of paragraph (f) of this section, it is exempt from the weekly inspection requirements in paragraph (c) of this section.

(4) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirements in paragraph (c) of this section, provided that each pump is visually inspected as often as practicable and at least bimonthly.

(d) ***Additional requirements for pressure relief devices in gas/vapor service.*** In addition to the requirements in paragraph (b) of this section, you must monitor each pressure relief device as specified in paragraph (d)(1) of this section, except as specified in paragraphs (d)(2) and (3) of this section.

(1) You must monitor each pressure relief device within 5 calendar days after each pressure release to detect leaks using the methods specified in § 60.5403b. A leak is detected if any emissions are observed using OGI or if an instrument reading of 500 ppmv or greater is provided using Method 21 of appendix A-7 to this part.

(2) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are onsite or within 30 calendar days after a pressure release, whichever is sooner, instead of within 5 calendar days as specified in paragraph (d)(1) of this section. No pressure relief device described in this paragraph may be allowed to operate for more than 30 calendar days after a pressure release without monitoring.

(3) 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 through the pressure relief device to a control device as described in paragraph (f) of this section is exempt from the requirements of paragraph (d)(1) of this section.

(e) ***Open-ended valves or lines.*** Each open-ended valve or line must be equipped with a cap, blind flange, plug, or a second valve, except as provided in paragraphs (e)(4) and (5) of this section. The cap, blind flange, plug, or second valve must seal the open end of the valve or line at all times except during operations requiring process fluid flow through the open-ended valve or line.

(1) If evidence of a leak is found at any time by AVO, or any other detection method, a leak is detected.

(2) Each open-ended valve or line equipped with a second valve must be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(3) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall remain closed at all other times.

(4) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of this section.

(5) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block-and-bleed system as specified in paragraphs (e) introductory text, (e)(2), and (3) of this section are exempt from the requirements of this section.

(f) ***Closed vent systems and control devices.*** Closed vent systems used to comply with the equipment leak provisions of this section must comply with the requirements in §§ 60.5411b and 60.5416b. Control devices used to comply with the equipment leak provisions of this section must comply with the requirements in §§ 60.5412b, 60.5415b(f), and 60.5417b.

(g) ***Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.*** If evidence of a potential leak is found at any time by AVO, or any other detection method, a leak is detected and must be repaired in accordance with paragraph (h) of this section.

(h) ***Repair requirements.*** When a leak is detected, you must comply with the requirements of paragraphs (h)(1) through (5) of this section, except as provided in paragraph (h)(6) of this section.

(1) A weatherproof and readily visible identification tag, marked with the equipment identification number, must be attached to the leaking equipment. The identification tag on equipment may be removed after it has been repaired.

(2) A first attempt at repair must be made as soon as practicable, but no later than 5 calendar days after the leak is detected. A first attempt at repair is not required if the leak is detected using OGI and the equipment identified as leaking would require elevating the repair personnel more than 2 meters above a support surface.

(i) First attempts at repair for pumps in light liquid or heavy liquid service include, but are not limited to, the practices described in paragraphs (h)(2)(i)(A) and (B) of this section, where practicable.

(A) Tightening the packing gland nuts.

(B) Ensuring that the seal flush is operating at design pressure and temperature.

(ii) For each valve where a leak is detected, you must comply with (h)(2)(ii)(A), (B) or (C), and (D) of this section.

(A) Repack the existing valve with a low-e packing.

(B) Replace the existing valve with a low-e valve; or

(C) Perform a drill and tap repair with a low-e injectable packing.

(D) An owner or operator is not required to utilize a low-e valve or low-e packing to replace or repack a valve if the owner or operator demonstrates that a low-e valve or low-e packing is not technically feasible. Low-e valve or low-e packing that is not suitable for its intended use is considered to be technically infeasible. Factors that may be considered in determining technical infeasibility include: retrofit requirements for installation (*e.g.,* re-piping or space limitation), commercial unavailability for valve type, or certain instrumentation assemblies.

(3) Repair of leaking equipment must be completed within 15 calendar days after detection of each leak, except as provided in paragraphs (h)(4), (5) and (6) of this section.

(4) If the repair for visual indications of liquids dripping for pumps in light liquid service can be made by eliminating visual indications of liquids dripping, you must make the repair within 5 calendar days of detection.

(5) If the repair for AVO or other indication of a leak for open-ended valves or lines; pumps, valves, or connectors in heavy liquid service; or pressure relief devices in light liquid or heavy liquid service can be made by eliminating the AVO, or other indication of a potential leak, you must make the repair within 5 calendar days of detection.

(6) 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 or as specified in paragraphs (h)(6)(i) through (v) of this section. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(i) Delay of repair of equipment is allowed for equipment which is isolated from the process, and which does not have the potential to emit methane or VOC.

(ii) Delay of repair for valves and connectors is allowed if the conditions in paragraphs (h)(6)(ii)(A) and (B) of this section are met.

(A) You must demonstrate that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(B) When repair procedures are conducted, the purged material is collected and destroyed or recovered in a control device complying with paragraph (f) of this section.

(iii) Delay of repair for pumps is allowed if the conditions in paragraphs (h)(6)(iii)(A) and (B) of this section are met.

(A) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(B) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(iv) If delay of repair is required to repack or replace the valve, you may use delay of repair. Delay of repair beyond a process unit shutdown is 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 next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(v) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive bimonthly monitoring results show no leak remains.

(i) ***Initial compliance.*** You must demonstrate initial compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by § 60.5410b(h).

(j) ***Continuous compliance.*** You must demonstrate continuous compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by § 60.5415b(j).

(k) ***Reporting.*** You must perform the reporting requirements as specified in § 60.5420b(b)(1) and (11) and § 60.5422b.

(l) ***Recordkeeping.*** You must perform the recordkeeping requirements as specified in § 60.5420b(c)(8), (10), and (12) and § 60.5421b.

§ 60.5401b What are the alternative GHG and VOC standards for process unit equipment affected facilities?

This section provides alternative standards for process unit equipment affected facilities located at an onshore natural gas processing plant. You may choose to comply with the standards in this section instead of the requirements in § 60.5400b. For purposes of the alternative standards provided in this section, you must comply with the requirements of paragraphs (a) through (m) of this section to reduce methane and VOC emissions from equipment leaks, except as provided in § 60.5402b.

(a) ***General standards.*** You must comply with the requirements in paragraphs (b) of this section for each pump in light liquid service. You must comply with the requirements of paragraph (c) of this section for each pressure relief device in gas/vapor service. You must comply with the requirements in paragraph (d) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (e) of this section for each closed vent system and control device used to comply with equipment leak provisions in this section. You must comply with paragraph (f) of this section for each valve in gas/vapor or light liquid service. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must comply with paragraph (h) of this section for each connector in gas/vapor and light liquid service. You must make repairs as specified in paragraph (i) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (j) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (k) of this section. You must perform the reporting requirements as specified in paragraph (l) of this section. You must perform the recordkeeping requirements as required in paragraph (m) of this section.

(1) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of § 60.5399b.

(2) Each piece of equipment is presumed to have the potential to emit methane or VOC unless an owner or operator demonstrates that the piece of equipment does not have the potential to emit methane or VOC. For a piece of equipment to be considered not to have the potential to emit methane or VOC, the methane and VOC content of a gaseous stream must be below detection limits using Method 18 of appendix A-6 to this part. Alternatively, if the piece of equipment is in wet gas service, you may choose to determine the methane and VOC content of the stream is below the detection limit of the methods described in ASTM E168-16(R2023), E169-16(R2022), or E260-96 (all incorporated by reference, see § 60.17).

(b) ***Pumps in light liquid service.*** You must monitor each pump in light liquid service monthly to detect leaks by the methods specified in § 60.5403b, except as provided in paragraphs (b)(2) through (4) of this section. A leak is defined as an instrument reading of 2,000 ppmv or greater. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in paragraphs (b)(2) through (4) of this section.

(1) In addition to the requirements in paragraph (b) of this section, you must conduct weekly visual inspections of all pumps in light liquid service for indications of liquids dripping from the pump seal. If there are indications of liquids dripping from the pump seal, you must follow the procedure specified in either paragraph (b)(1)(i) or (ii) of this section.

(i) Monitor the pump within 5 days using the methods specified in § 60.5403b. A leak is defined as an instrument reading of 2,000 ppmv or greater.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak as specified in paragraph (i) of this section.

(2) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements in paragraph (b) of this section, provided the requirements specified in paragraphs (b)(2)(i) through (vi) of this section are met.

(i) Each dual mechanical seal system meets the requirements of paragraphs (b)(2)(i)(A), (B), or (C) of this section.

(A) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(B) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of paragraph (e) of this section; or

(C) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(ii) The barrier fluid system is in heavy liquid service or does not have the potential to emit methane or VOC.

(iii) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(iv) Each pump is checked according to the requirements in paragraph (b)(1) of this section.

(v) Each sensor meets the requirements in paragraphs (b)(2)(v)(A) through (C) of this section.

(A) Each sensor as described in paragraph (b)(2)(iii) of this section is checked daily or is equipped with an audible alarm.

(B) You determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(C) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (b)(2)(v)(B) of this section, a leak is detected.

(3) Any pump that is designated, as described in § 60.5421b(b)(12), for no detectable emissions, as indicated by an instrument reading of less than 500 ppmv above background, is exempt from the requirements of paragraphs (b) introductory text, (b)(1), and (2) of this section if the pump:

(i) Has no externally actuated shaft penetrating the pump housing;

(ii) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background as measured by the methods specified in § 60.5403b; and

(iii) Is tested for compliance with paragraph (b)(3)(ii) of this section initially upon designation, annually, and at other times requested by the Administrator.

(4) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process, fuel gas system, or a control device that complies with the requirements of paragraph (e) of this section, it is exempt from paragraphs (b), (b)(1) through (3) of this section, and the repair requirements of paragraph (i) of this section.

(5) Any pump that is designated, as described in § 60.5421b(b)(13), as an unsafe-to-monitor pump is exempt from the inspection and monitoring requirements of paragraphs (b), (b)(1) and (b)(2)(iv) through (vi) of this section if the conditions in paragraph (b)(5)(i) and (ii) of this section are met.

(i) You demonstrate that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (b) of this section; and

(ii) You have a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and you repair the equipment according to the procedures in paragraph (i) of this section if a leak is detected.

(6) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirements in paragraph (b)(1) and (b)(2)(iv) of this section, and the daily requirements of paragraph (b)(2)(v) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

(c) ***Pressure relief devices in gas/vapor service.*** You must monitor each pressure relief device quarterly using the methods specified in § 60.5403b. A leak is defined as an instrument reading of 500 ppmv or greater above background.

(1) In addition to the requirements in paragraph (c) introductory text of this section, after each pressure release, you must monitor each pressure relief device within 5 calendar days after each pressure release to detect leaks. A leak is detected if an instrument reading of 500 ppmv or greater is provided using the methods specified in § 60.5403b(b).

(2) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are onsite or within 30 calendar days after a pressure release, whichever is sooner, instead of within 5 calendar days as specified in paragraph (c)(1) of this section.

(3) No pressure relief device described in paragraph (c)(2) of this section may be allowed to operate for more than 30 calendar days after a pressure release without monitoring.

(4) 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 through the pressure relief device to a control device as described in paragraph (e) of this section is exempt from the requirements of paragraph (c) introductory text and (c)(1) of this section.

(5) Pressure relief devices equipped with a rupture disk are exempt from the requirements of paragraphs (c)(1) and (2) of this section provided you install a new rupture disk 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 paragraph (i)(4) of this section.

(d) ***Open-ended valves or lines.*** Each open-ended valve or line must be equipped with a cap, blind flange, plug, or a second valve, except as provided in paragraphs (d)(4) and (5) of this section. The cap, blind flange, plug, or second valve must seal the open end of the valve or line at all times except during operations requiring process fluid flow through the open-ended valve or line.

(1) If evidence of a leak is found at any time by AVO, or any other detection method, a leak is detected and must be repaired in accordance with paragraph (i) of this section. A leak is defined as an instrument reading of 500 ppmv or greater if Method 21 of appendix A-7 to this part is used.

(2) Each open-ended valve or line equipped with a second valve must be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(3) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall remain closed at all other times.

(4) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (d) introductory text, and (d)(1) through (3) of this section.

(5) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block-and-bleed system as specified in paragraphs (d) introductory text, (d)(2), and (3) of this section are exempt from the requirements of this section.

(e) ***Closed vent systems and control devices.*** Closed vent systems used to comply with the equipment leak provisions of this section must comply with the requirements in §§ 60.5411b and 60.5416b. Control devices used to comply with the equipment leak provisions of this section must comply with the requirements in §§ 60.5412b, 60.5415b(f), and 60.5417b.

(f) ***Valves in gas/vapor and light liquid service.*** You must monitor each valve in gas/vapor and in light liquid service quarterly to detect leaks by the methods specified in § 60.5403b, except as provided in paragraphs (h)(3) through (5) of this section.

(1) A valve that begins operation in gas/vapor service or in light liquid service after the initial startup date for the process unit must be monitored for the first time within 90 days after the end of its startup period to ensure proper installation, except for a valve that replaces a leaking valve and except as provided in paragraphs (h)(3) through (5) of this section.

(2) An instrument reading of 500 ppmv or greater is a leak. You must repair each leaking valve according to the requirements in paragraph (i) of this section.

(3) Any valve that is designated, as described in § 60.5421b(b)(12), for no detectable emissions, as indicated by an instrument reading of less than 500 ppmv above background, is exempt from the requirements of paragraphs (f) of this section if the valve:

(i) Has no externally actuating mechanism in contact with the process fluid;

(ii) Is operated with emissions less than 500 ppmv above background as determined by the methods specified in § 60.5403b; and ts of paragraph (h) of this section if the requirements in paragraph (i)(5)(i) through (iii) of this section are met.

emonstrate that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a rt surface.

ocess unit within which the valve is located has less than 3.0 percent of its total number of valves designated as lt-to-monitor.

ave a written plan that requires monitoring of the at least once per calendar year.

nd connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service. If evidence of a found at any time by AVO, or any other detection method, you must comply with either paragraph (g)(1) or (2) of this

nonitor the equipment within 5 calendar days by the method specified in § 60.5403b and repair any leaks detected o paragraph (i) of this section. An instrument reading of 10,000 ppmv or greater is defined as a leak.

esignate the AVO, or other indication of a leak as a leak and repair the leak according to paragraph (i) of this section.

s/vapor service and in light liquid service. You must initially monitor all connectors in the process unit for leaks by the months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been aks prior to the compliance date, no initial monitoring is required provided either no process changes have been made oring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably mpliance despite process changes. If required to monitor because of a process change, you are required to monitor only s involved in the process change.

nonitor all connectors in gas/vapor service and in light liquid service annually, except as provided in § 60.5399b, (e) of this section or paragraph (h)(2) of this section.

tor that is designated, as described in § 60.5421b(b)(13), as an unsafe-to-monitor connector is exempt from the ts of paragraphs (h) introductory text and (h)(1) of this section if the requirements of paragraphs (h)(2)(i) and (ii) of this met.

emonstrate the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger onsequence of complying with paragraphs (h) introductory text and (h)(1) of this section; and

ave a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times, but ore frequently than the periodic monitoring schedule otherwise applicable, and you repair the equipment according to the dures in paragraph (i) of this section if a leak is detected.

e, ceramic, or ceramic-line connectors.

onnector that is inaccessible or that is ceramic or ceramic-lined (*e.g.,* porcelain, glass, or glass-lined), is exempt from the oring requirements of paragraphs (h) and (h)(1) of this section, from the leak repair requirements of paragraph (i) of this n, and from the recordkeeping and reporting requirements of §§ 60.5421b and 60.5422b. An inaccessible connector is at meets any of the specifications in paragraphs (h)(3)(i)(A) through (F) of this section, as applicable.

uried.

nsulated in a manner that prevents access to the connector by a monitor probe.

bstructed by equipment or piping that prevents access to the connector by a monitor probe.

nable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to .6 meters (25 feet) above the ground.

naccessible because it would require elevating monitoring personnel more than 2 meters (7 feet) above a permanent upport surface or would require the erection of scaffold.

(F) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines or would risk damage to equipment.

(ii) If any inaccessible, ceramic, or ceramic-lined connector is observed by AVO or other means to be leaking, the indications of a leak to the atmosphere by AVO or other means must be eliminated as soon as practicable.

(4) Connectors which are part of an instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (h)(3) of this section, are not subject to the recordkeeping requirements of § 60.5421b(b)(1).

(i) ***Repair requirements.*** When a leak is detected, comply with the requirements of paragraphs (i)(1) through (5) of this section, except as provided in paragraph (i)(6) of this section.

(1) A weatherproof and readily visible identification tag, marked with the equipment identification number, must be attached to the leaking equipment. The identification tag on the equipment may be removed after it has been repaired.

(2) A first attempt at repair must be made as soon as practicable, but no later than 5 calendar days after the leak is detected.

(i) First attempts at repair for pumps in light liquid or heavy liquid service include, but are not limited to, the practices described in paragraphs (i)(2)(i)(A) and (B) of this section, where practicable.

(A) Tightening the packing gland nuts.

(B) Ensuring that the seal flush is operating at design pressure and temperature.

(ii) For each valve where a leak is detected, you must comply with (h)(2)(ii)(A), (B) or (C), and (D) of this section.

(A) Repack the existing valve with a low-e packing.

(B) Replace the existing valve with a low-e valve; or

(C) Perform a drill and tap repair with a low-e injectable packing.

(D) An owner or operator is not required to utilize a low-e valve or low-e packing to replace or repack a valve if the owner or operator demonstrates that a low-e valve or low-e packing is not technically feasible. Low-e valve or low-e packing that is not suitable for its intended use is considered to be technically infeasible. Factors that may be considered in determining technical infeasibility include: retrofit requirements for installation (*e.g.,* re-piping or space limitation), commercial unavailability for valve type, or certain instrumentation assemblies.

(3) Repair of leaking equipment must be completed within 15 calendar days after detection of each leak, except as provided in paragraph (i)(4), (5), or (6) of this section.

(4) If the repair for visual indications of liquids dripping for pumps in light liquid service can be made by eliminating visual indications of liquids dripping, you must make the repair within 5 calendar days of detection.

(5) If the repair for AVO or other indication of a leak for open-ended lines or valves; pumps, valves, or connectors in heavy liquid service; or pressure relief devices in light liquid or heavy liquid service can be made by eliminating the AVO, or other indication of a potential leak, you must make the repair within 5 calendar days of detection.

(6) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 calendar days is technically infeasible without a process unit shutdown or as specified in paragraphs (i)(6)(i) through (v) of this section. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 calendar days after startup of the process unit.

(i) Delay of repair of equipment will be allowed for equipment which is isolated from the process, and which does not have the potential to emit methane or VOC.

(ii) Delay of repair for valves and connectors will be allowed if the conditions in paragraphs (i)(6)(ii)(A) and (B) are met.

(A) You demonstrate that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(B) When repair procedures are conducted, the purged material is collected and destroyed or recovered in a control device complying with paragraph (e) of this section.

(iii) Delay of repair for pumps will be allowed if the conditions in paragraphs (i)(6)(iii)(A) and (B) are met.

(A) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(B) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(iv) If delay of repair is required to repack or replace the valve, you may use delay of repair. 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 next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(v) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring results show no leak remains.

(j) ***Initial compliance.*** You must demonstrate initial compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by § 60.5410b(h).

(k) ***Continuous compliance.*** You must demonstrate continuous compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by § 60.5415b(j).

(l) ***Reporting.*** You must perform the reporting requirements as specified in §§ 60.5420b(b)(1), (b)(11), and 60.5422b.

(m) ***Recordkeeping.*** You must perform the recordkeeping requirements as specified in § 60.5420b(c)(8), (10), (12), and § 60.5421b.

§ 60.5402b What are the exceptions to the GHG and VOC standards for process unit equipment affected facilities?

(a) You may comply with the following exceptions to the provisions of §§ 60.5400b(a) and 60.5401b(a), as applicable.

(b) Pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor and light liquid service, and connectors in gas/vapor service and in light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas may comply with the exceptions specified in paragraphs (b)(1) or (2) of this section.

(1) You are exempt from the bimonthly OGI monitoring as required under § 60.5400b(b).

(2) You are exempt from the routine Method 21 of appendix A-7 monitoring requirements of § 60.5401b(b), (c), (f), and (h), if complying with the alternative standards of § 60.5401b.

(c) Pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor and light liquid service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the monitoring requirements § 60.5400b(b) and (c) and § 60.5401b(b), (c), (f) and (h).

(d) You may use the following provisions instead of § 60.5403b(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 degrees Celsius (302 degrees Fahrenheit) as determined by ASTM D86-96 (incorporated by reference, see § 60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 degrees Celsius (302 degrees Fahrenheit) as determined by ASTM D86-96 (incorporated by reference, see § 60.17).

(e) Equipment that is in vacuum service, except connectors in gas/vapor and light liquid service, is excluded from the requirements of § 60.5400b(b) through (g), if it is identified as required in § 60.5421b(b)(15). Equipment that is in vacuum service is excluded from the requirements of § 60.5401b(b) through (g) if it is identified as required in § 60.5421b(b)(15).

(f) Equipment that you designate as having the potential to emit methane or VOC less than 300 hr/yr is excluded from the requirements of § 60.5400b(b) through (g) and § 60.5401b(b) through (h), if it is identified as required in § 60.5421b(b)(16) and it meets any of the conditions specified in paragraphs (f)(1) through (3) of this section.

(1) The equipment has the potential to emit methane or VOC only during startup and shutdown.

(2) The equipment has the potential to emit methane or VOC only during process malfunctions or other emergencies.

(3) The equipment is backup equipment that has the potential to emit methane or VOC only when the primary equipment is out of service.

§ 60.5403b What test methods and procedures must I use for my process unit equipment affected facilities?

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

(b) You must determine compliance with the standards in § 60.5401b as follows:

(1) Method 21 of appendix A-7 to this part shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 to this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppmv of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppmv greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppmv above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately or equal to 10,000 ppmv. If only one scale on an instrument will be used during monitoring, you need not calibrate the scales that will not be used during that day's monitoring.

(iii) Verification that your monitoring equipment meets the requirements specified in Section 6.0 of Method 21 of appendix A-7 to this part. For purposes of instrument capability, the leak definition shall be 500 ppmv or greater methane using a FID-based instrument for valves and connectors and 2,000 ppmv methane or greater for pumps. If you wish to use an analyzer other than a FID-based instrument, you must develop a site-specific leak definition that would be equivalent to 500 ppmv methane using a FID-based instrument (*e.g.,* 10.6 eV PID with a specified isobutylene concentration as the leak definition would provide equivalent response to your compound of interest).

(2) The instrument must be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 to this part. At minimum, you must also conduct precision tests at the interval specified in Method 21 of appendix A-7 to this part, Section 8.1.2, and a calibration drift assessment at the end of each monitoring day. The calibration drift assessment must be conducted as specified in paragraph (b)(2)(i) of this section. Corrective action for drift assessments is specified in paragraphs (b)(2)(ii) and (iii) of this section.

(i) Check the instrument using the same calibration gas that was used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 to this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. If multiple scales are used, record the instrument reading for each scale used. Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage.

(ii) If a calibration drift assessment shows a negative drift of more than 10 percent, then all equipment with instrument readings between the fugitive emission definition multiplied by (100 minus the percent of negative drift) divided by 100 and the fugitive emission definition that was monitored since the last calibration must be re-monitored.

(iii) If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the fugitive emission definition and below the fugitive emission definition multiplied by (100 plus the percent of positive drift) divided by 100 monitored since the last calibration may be re-monitored.

(c) You shall determine compliance with the no detectable emission standards in § 60.5401b(b), (c), and (f) as specified in paragraphs (c)(1) and (2) of this section.

(1) The requirements of paragraph (b) of this section shall apply.

(2) Method 21 of appendix A-7 to this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppmv for determining compliance.

(d) You shall demonstrate that a piece of equipment is in light liquid service by showing that all of the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in H_2O at 68 °F). Standard reference texts or ASTM D2879-83, -96, or -97 (all incorporated by reference, see § 60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in H_2O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(e) Samples used in conjunction with paragraphs (d) and (e) of this section shall be representative of the process fluid that is contained in or contacts the equipment, or the gas being combusted in the flare.

§ 60.5405b What standards apply to sweetening unit affected facilities?

(a) During the initial performance test required by § 60.8(b), you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_i) to be determined from table 3 to this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_c) to be determined from table 4 to this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(c) You must demonstrate initial compliance with the standards that apply to sweetening unit affected facilities as required by § 60.5410b(i).

(d) You must demonstrate continuous compliance with the standards that apply to sweetening unit affected facilities as required by § 60.5415b(k).

(e) You must perform the reporting as required by § 60.5420b(a)(1), (b)(1), and § 60.5423b and the recordkeeping as required by § 60.5423b.

§ 60.5406b What test methods and procedures must I use for my sweetening unit affected facilities?

(a) In conducting the performance tests required in § 60.8, you must use the test methods in appendix A to this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(b) During a performance test required by § 60.8, you must determine the minimum required reduction efficiencies (Z) of SO_2 emissions as required in § 60.5405b(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

Equation 1 to paragraph (b)(1)

$$X = KQ_aY$$

Where:
X = average sulfur feed rate, Mg/D (LT/D).
Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).
Y = average H_2S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.
K = (32 kg S/kg-mole)/((24.04 dscm/kg-mole)(1000 kg S/Mg)).
= 1.331×10^{-3}Mg/dscm, for metric units.
= (32 lb S/lb-mole)/((385.36 dscf/lb-mole)(2240 lb S/long ton)).
= 3.707×10^{-5} long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in § 60.5408b or a chromatographic procedure following ASTM E260-96 (incorporated by reference, see § 60.17) to determine the H_2S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H_2S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (3) of this section, tables 3 and 4 to this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO_2 emissions.

(c) You must determine the emission reduction efficiency (R) achieved by the sulfur recovery technology as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

Equation 2 to paragraph (c)(1)

$$R = (100S)/(S + E)$$

(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage vessels. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

Equation 3 to paragraph (c)(3)

$$E = C_eQ_{sd}/K_1$$

Where:
E = emission rate of sulfur per run, kg/hr.
C_e = concentration of sulfur equivalent (SO^{2+} reduced sulfur), g/dscm (lb/dscf).
Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).
K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO_2 and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of appendix A-1 to this part to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m^2 or more, and the centroid is more than 1 m (39 in) from the wall.

(i) You must use Method 6 or 6C of appendix A-4 to this part to determine the SO_2 concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent. In place of Method 6 of appendix A to this part, you may use ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference, see § 60.17).

(ii) You must use Method 2 of appendix A-1 to this part to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged.

(iii) You must use Method 4 of appendix A-2 to this part for moisture content. Alternatively, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

(iv) You must use Method 15 of appendix A-5 to this part to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft^3/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppmv reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(v) You must use Method 16A of appendix A-6 to this part or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference, see § 60.17) to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use EPA Method 2 of appendix A-1 to this part to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

EDITORIAL NOTE

Editorial Note: At 89 FR 17080, Mar. 8, 2024, § 60.5406b was added with two paragraphs (c)(4)(iv), the second one occurring after paragraph (c)(4)(v).

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§ 60.5407b What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities?

(a) If your sweetening unit affected facility is subject to the provisions of § 60.5405b(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

(1) The accumulation of sulfur product over each 24-hour period. The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate or may be a procedure for measuring and recording the sulfur liquid levels in the storage vessels with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ±2 percent of the 24-hour sulfur accumulation.

(2) The H_2S concentration in the acid gas from the sweetening unit for each 24-hour period. At least one sample per 24-hour period must be collected and analyzed using the equation specified in § 60.5406b(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is within ±20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ±20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) The average acid gas flow rate from the sweetening unit. You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) The sulfur feed rate (X). For each 24-hour period, you must compute X using the equation specified in § 60.5406b(b)(1).

(5) The required sulfur dioxide emission reduction efficiency for the 24-hour period. You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of § 60.5405b(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere. The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405b(b) will be between 30 percent and 70 percent of the

measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with § 60.5405b(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ±1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of § 60.8 to demonstrate compliance with the standards under § 60.5405b, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under § 60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved using a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO_2 equivalent in the gases discharged to the atmosphere. The SO_2 equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405b(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock interval. The 24-hour interval may begin and end at any selected clock time but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in § 60.5406b(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H_2S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

Equation 1 to paragraph (e)

$$R = \frac{K_2 S}{X}$$

Where:
R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.
K_2 = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).
S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).
X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1) and (3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by § 60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1) and (3), and (c) of this section must be subject to the emission monitoring requirements of § 60.13. For conducting the continuous emission monitoring system performance evaluation required by § 60.13(c), Performance Specification 2 of appendix B to this part must apply, and Method 6 of appendix A-4 to this part must be used for systems required by paragraph (b) of this section. In place of Method 6 of appendix A-4 to this part, ASME PTC 19.10-1981 (incorporated by reference, see § 60.17) may be used.

§ 60.5408b What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A-80-20-A, Entry II-I-67).

(a) ***Sampling.*** When an instantaneous sample is desired and H_2S concentration is 10 grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than 10 grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) ***Apparatus.*** (See figure 1 to this section.) A 100- or 500-ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top that connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) ***Reagents.***

(1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide (KI) for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml = 0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) ***Procedure.*** (Refer to figure 1 to this section.) Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions start to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine through (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) ***Blank testing.*** (Refer to figure 1 to this section.) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then,

Equation 1 to paragraph (e)

$$\text{Grains } H_2S \text{ per 100 cubic feet of gas} = 100\,(D-C)$$

(f) ***Test sensitivity.*** Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S-free gas or air, is required.

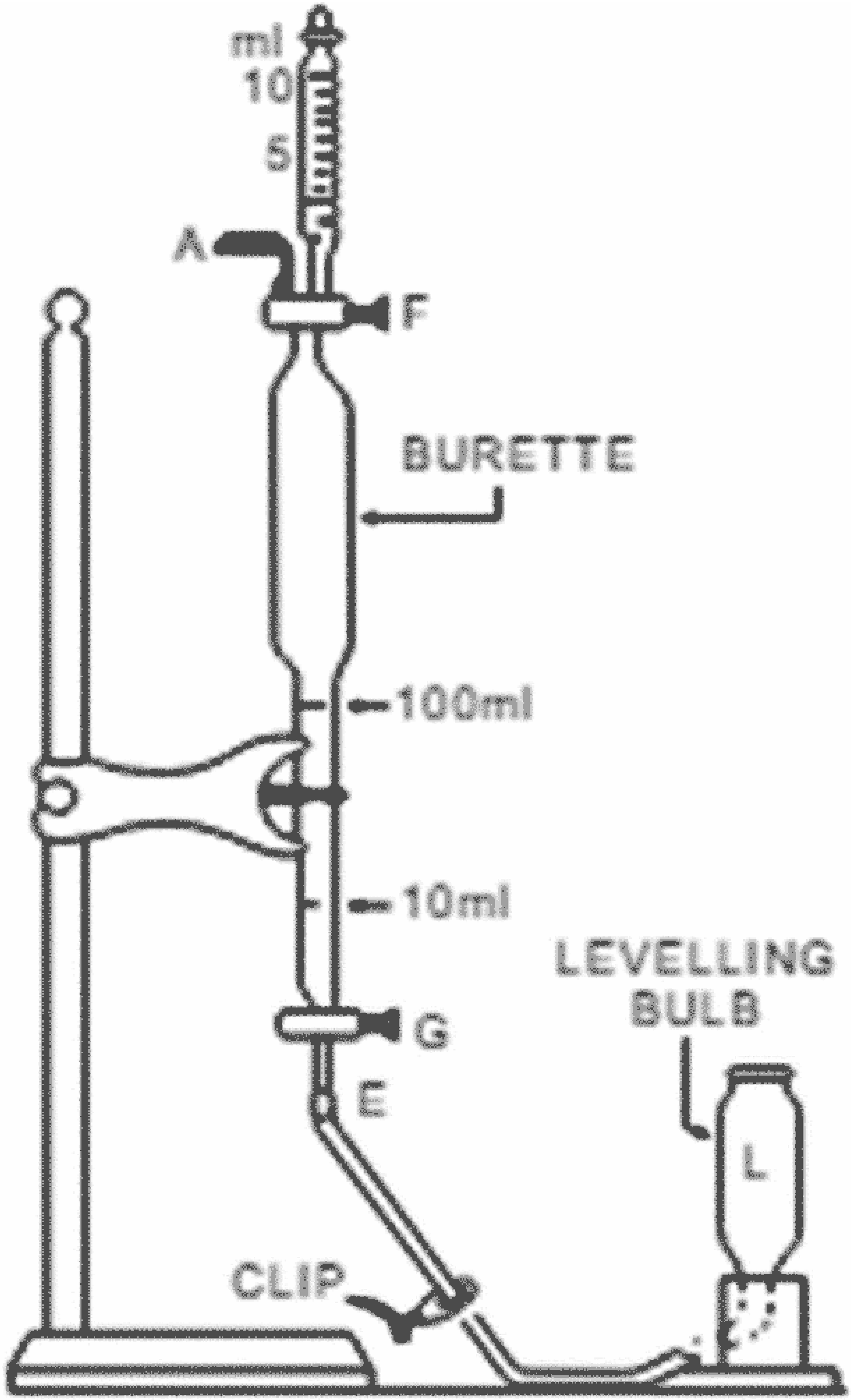

Figure 1 to § 60.5408b. Tutwiler burette (lettered items mentioned in text).

§ 60.5410b How do I demonstrate initial compliance with the standards for each of my affected facilities?

You must determine initial compliance with the standards for each affected facility using the requirements of paragraphs (a) through (k) of this section. Except as otherwise provided in this section, the initial compliance period begins on the date specified in § 60.5370b and ends no later than 1 year after that date. The initial compliance period may be less than 1 full year.

(a) ***Well completion standards for well affected facilities.*** To achieve initial compliance with the GHG and VOC standards for each well completion operation conducted at your well affected facility as required by § 60.5375b, you must comply with paragraphs (a)(1) through (4) of this section.

(1) You must submit the notification required in § 60.5420b(a)(2).

ubmit the initial annual report for your well affected facility as required in § 60.5420b(b)(1) and (3).

ly by using a liquids unloading technology or technique that does not vent to the atmosphere according to § 60.5376b(a) st maintain the records specified in § 60.5420b(c)(2)(i).

ly by using a liquids unloading technology or technique that vents to the atmosphere according to § 60.5376b(a)(2), (b) must comply with paragraphs (b)(3)(i) and (ii) of this section.

y best management practices to minimize venting of methane and VOC emissions as specified in § 60.5376b(c) for gas well liquids unloading operation.

ain the records specified in § 60.5420b(c)(2)(ii).

ly by using § 60.5376b(g), you must comply with paragraphs (b)(4)(i) through (vii) of this section.

e methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of § 60.5413b.

a closed vent system that meets the requirements of § 60.5411b(a) and (c) to capture all emissions and route all ions to a control device that meets the conditions specified in § 60.5412b.

ct an initial performance test as required in § 60.5413b within 180 days after the initial gas well liquids unloading tion, or install a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e), and y with the continuous compliance requirements of § 60.5415b(f).

ust conduct the initial inspections required in § 60.5416b(a) and (b).

ust install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) through (i), as able.

ust maintain the records specified in § 60.5420b(c)(2)(iii),(c)(8) and (c)(10) through (13), as applicable and submit the s as required by § 60.5420b(b)(11) through (13), as applicable.

vell standards for well affected facility. To demonstrate initial compliance with the GHG and VOC standards for each well as required by § 60.5377b, you must comply with paragraphs (c)(1) through (3) of this section.

ly with the requirements of § 60.5377b(a), you must maintain the records specified in § 60.5420b(c)(3)(i), (ii), and (iv).

ted gas wells that comply with § 60.5377b(f) based on a demonstration and certification that it is not feasible to comply aph (a)(1), (2), (3), and (4) of this section due to technical reasons in accordance with paragraph § 60.5377b(g), you ly with paragraphs (c)(2)(i) and (ii) of this section.

nent the technical reasons why it is infeasible to route recovered associated gas into a gas gathering flow line or tion system to a sales line, use it as an onsite fuel source, use it for another useful purpose that a purchased fuel or raw ial would serve, or re-inject it into the well or inject it into another well, and submit this documentation in the initial annual .

t the certification as required by § 60.5377b(g).

ly with § 60.5377b(d) or (f), you must comply with paragraphs (c)(3)(i) through (vi) of this section.

e methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of § 60.5413b.

a closed vent system that meets the requirements of § 60.5411b(a) and (c) to capture the associated gas and route the red associated gas to a control device that meets the conditions specified in § 60.5412b.

ct an initial performance test as required in § 60.5413b within 180 days after initial startup or by May 7, 2024, whichever s later, or install a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e) and ust comply with the continuous compliance requirements of § 60.5415b(f).

(iv) Conduct the initial inspections required in § 60.5416b(a) and (b).

(v) Install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) through (i), as applicable.

(vi) Maintain the records specified in § 60.5420b(c)(3)(iv) and (c)(8) and (c)(10) through (13), as applicable.

(4) You must submit the initial annual report for your associated gas well as required in § 60.5420b(b)(1) and (4) and (b)(11) through (13), as applicable.

(d) ***Centrifugal compressor affected facility.*** To demonstrate initial compliance with the GHG and VOC standards for your centrifugal compressor affected facility that uses a wet seal as required by § 60.5380b, you must comply with paragraphs (d)(1) through (5) and paragraphs (d)(7) and (8) of this section. To demonstrate initial compliance with the GHG and VOC alternative standards for your centrifugal compressor affected facility that is a self-contained wet seal centrifugal compressor or a centrifugal compressor at the Alaska North Slope equipped with sour seal oil separator and capture system as allowed by § 60.5380b, you must comply with paragraphs (d)(6) through (8) of this section. To demonstrate initial compliance with the GHG and VOC alternative standards for your dry seal centrifugal compressor as required by § 60.5380b, you must comply with paragraphs (d)(6) through (8) of this section.

(1) You must reduce methane and VOC emissions by 95.0 percent or greater according to § 60.5380b(a)(1) and (2) and as demonstrated by the requirements of § 60.5413b, or you must route emissions to a process according to § 60.5380b(a)(3).

(2) If you use a control device to reduce emissions to comply with § 60.5380b(a)(1) and (2), you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411b(b) that is connected through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and is routed to a control device that meets the conditions specified in § 60.5412b. If you comply with § 60.5380b(a)(3) by routing the closed vent system to a process as an alternative to routing the closed vent system to a control device, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411b(b), and route captured vapors through a closed vent system that meets the requirements of § 60.5411b(a) and (c).

(3) If you use a control device to comply with § 60.5380b(a)(1) and (2), you must conduct an initial performance test as required in § 60.5413b within 180 days after initial startup or by May 7, 2024, whichever date is later, or install a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e) and you must comply with the continuous compliance requirements of § 60.5415b(f).

(4) If you use a control device to comply with § 60.5380b(a)(1) and (2) or comply with § 60.5380b(a)(3) by routing to a process, you must conduct the initial inspections required in § 60.5416b(a) and (b).

(5) If you use a control device to comply with § 60.5380b(a)(1) and (2), you must install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) through (i), as applicable.

(6) You must maintain the volumetric flow rates for your centrifugal compressors as specified in paragraphs (d)(6)(i) through (iii) of this section, as applicable. You must conduct your initial annual volumetric measurement as required by § 60.5380b(a)(5).

(i) For your self-contained wet seal centrifugal compressors, you must maintain the volumetric flow rate at or below 3 scfm per seal.

(ii) For your centrifugal compressor on the Alaska North Slope equipped with sour seal oil separator and capture system, you must maintain the volumetric flow rate at or below 9 scfm per seal.

(iii) For your dry seal compressor, you must maintain the volumetric flow rate at or below 10 scfm per seal.

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in § 60.5420b(b)(1) and (5) and (b)(11) through (13), as applicable.

(8) You must maintain the records as specified in § 60.5420b(c)(4) and (c)(8) through (13), as applicable.

(e) ***Reciprocating compressor affected facility.*** To demonstrate initial compliance with the GHG and VOC standards for each reciprocating compressor affected facility as required by § 60.5385b, you must comply with paragraphs (e)(1) through (7) of this section.

(1) If you comply with § 60.5385b by maintaining volumetric flow rate at or below 2 scfm per cylinder (or a combined cylinder volumetric flow rate greater than the number of compression cylinders multiplied by 2 scfm) as required by § 60.5385b(a), you must maintain volumetric flow rate at or below 2 scfm and you must conduct your initial annual volumetric flow rate measurement as required by § 60.5385b(a)(1).

(2) If you comply with § 60.5385bby collecting the methane and VOC emissions from your reciprocating compressor rod packing using a rod packing emissions collection system as required by § 60.5385b(d)(1), you must equip the reciprocating compressor with a cover that meets the requirements of § 60.5411b(b), route emissions to a process through a closed vent system that meets the requirements of § 60.5411b(a) and (c), and you must conduct the initial inspections required in § 60.5416b(a) and (b).

(3) If you comply with § 60.5385b(d) by collecting the emissions from your rod packing emissions collection system by using a control device to reduce VOC and methane emissions by 95.0 percent as required by § 60.5385b(d)(2), you must equipe the reciprocating compressor with a cover that meets the requirements of § 60.5411b(b), route emissions to a control device that meets the conditions specified in § 60.5412b through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and you must conduct the initial inspections required in § 60.5416b(a) and (b).

(4) If you comply with § 60.5385b(d)(2), you must conduct an initial performance test as required in § 60.5413b within 180 days after initial startup or by May 7, 2024, whichever date is later, or install a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e) and you must comply with the continuous compliance requirements of § 60.5415b(f).

(5) If you comply with § 60.5385b(d)(2), you must install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) through (i), as applicable.

(6) You must submit the initial annual report for your reciprocating compressor as required in § 60.5420b(b)(1), (6), and (11) through (13), as applicable.

(7) You must maintain the records as specified in § 60.5420b(c)(5) and (8) through (13) as applicable.

(f) ***Process controller affected facility.*** To demonstrate initial compliance with GHG and VOC emission standards for your process controller affected facility as required by § 60.5390b, you must comply with paragraphs (f)(1) through (5) of this section, as applicable. If you change compliance methods, you must perform the applicable compliance demonstrations of paragraphs (f)(1) through (3) of this section again for the new compliance method, note the change in compliance method in the annual report required by § 60.5420b(b)(7)(iv), and maintain the records required by paragraph (f)(5) of this section for the new compliance method.

(1) For process controller affected facilities complying with the requirements of § 60.5390b(a), you must demonstrate that your process controller affected facility does not emit any VOC or methane to the atmosphere by meeting the requirements of paragraphs (f)(1)(i) or (ii) of this section.

(i) If you comply by routing the emissions to a process, you must meet the requirements for closed vent systems specified in paragraph (f)(3) of this section.

(ii) If you comply by using a self-contained natural gas-driven process controller, you must conduct an initial no identifiable emissions inspection as required by § 60.5416b(b).

(2) For each process controller affected facility located at a site in Alaska that does not have access to electrical power, you must demonstrate initial compliance with § 60.5390b(b)(1) and (2) or with § 60.5390b(b)(3), instead of complying with paragraph § 60.5390b(a), by meeting the requirements specified in (f)(2)(i) through (v) of this section for each process controller, as applicable.

(i) For each process controller in the process controller affected facility operating with a bleed rate of less than or equal to 6 scfh, you must maintain records in accordance with § 60.5420b(c)(6)(iii)(A) that demonstrate the process controller is designed and operated to achieve a bleed rate less than or equal to 6 scfh.

(ii) For each process controller in the process controller affected facility operating with a bleed rate greater than 6 scfh, you must maintain records that demonstrate that a controller with a higher bleed rate than 6 scfh is required based on a specific functional need for that controller as specified in § 60.5420b(c)(6)(iii)(B).

(iii) For each intermittent vent process controller in the process controller affected facility you must demonstrate that each intermittent vent controller does not emit to the atmosphere during idle periods by conducting initial monitoring in accordance with § 60.5390b(b)(2)(ii).

(iv) For each process controller affected facility that complies by reducing methane and VOC emissions from all controllers in the process controller affected facility by 95.0 percent in accordance with § 60.5390b(b)(3), you must comply with paragraphs (b)(2)(iv)(A) through (D) of this section.

(A) Reduce methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of § 60.5413b.

(B) Route all process controller affected facility emissions to a control device that meets the conditions specified in § 60.5412b through a closed vent system that meets the requirements specified in paragraph (f)(3) of this section.

(C) Conduct an initial performance test as required in § 60.5413b within 180 days after initial startup or by May 7, 2024, whichever date is later, or install a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e) and you must comply with the continuous compliance requirements of § 60.5415b(f).

(D) Install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) through (i), as applicable.

(3) For each closed vent system used to comply with § 60.5390b, you must meet the requirements specified in paragraphs (f)(3)(i) and (ii) of this section.

(i) Install a closed vent system that meets the requirements of § 60.5411b(a) and (c).

(ii) Conduct the initial inspections of the closed vent system and bypasses, if applicable, as required in § 60.5416b(a) and (b).

(4) You must submit the initial annual report for your process controller affected facility as required in § 60.5420b(b)(1) and (7).

(5) You must maintain the records as specified in § 60.5420b(c)(6).

(g) ***Pump affected facility.*** To demonstrate initial compliance with the GHG and VOC standards for your pump affected facility as required by § 60.5393b, you must comply with paragraphs (g)(1) through (4) of this section, as applicable. If you change compliance methods, you must perform the applicable compliance demonstrations of paragraphs (g)(1) and (2) of this section again for the new compliance method, note the change in compliance method in the annual report required by § 60.5420b(b)(10)(v)(C), and maintain the records required by paragraph (g)(4) of this section for the new compliance method.

(1) For pump affected facilities complying with the requirements of § 60.5393b(a) or (b)(2) by routing emissions to a process, you must meet the requirements specified in paragraphs (g)(ii) and (iv) of this section. For pump affected facilities complying with the requirements of § 60.5393b(b)(3), you must meet the requirements specified in paragraphs (g)(1)(i) through (v) of this section.

(i) Reduce methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of § 60.5413b.

(ii) Install a closed vent system that meets the requirements of § 60.5411b(a) and (c) to capture all emissions from all pumps in the pump affected facility and route all emissions to a process or control device that meets the conditions specified in § 60.5412b.

(iii) Conduct an initial performance test as required in § 60.5413b within 180 days after initial startup or by May 7, 2024, whichever date is later, or install a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e) and you must comply with the continuous compliance requirements of § 60.5415b(f).

(iv) Conduct the initial inspections of the closed vent system and bypasses, if applicable, as required in § 60.5416b(a) and (b).

(v) Install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) through (i), as applicable.

(2) Submit the certifications specified in paragraphs (g)(2)(i) through (iii) of this section, as applicable.

(i) The certification required by § 60.5393b(b)(3) that there is no vapor recovery unit on site and that there is a control device on site, but it does not achieve a 95.0 percent emissions reduction.

(ii) The certification required by § 60.5393b(b)(4) that there is no control device or process available on site.

(iii) The certification required by § 60.5393b(b)(5)(i) that it is technically infeasible to capture and route the pump affected facility emissions to a process or an existing control device.

(3) You must submit the initial annual report for your pump affected facility as specified in § 60.5420b(b)(1), (10), and (b)(11) through (13), as applicable.

(4) You must maintain the records for your pump affected facility as specified in § 60.5420b(c)(8) and (c)(10) through (13), as applicable, and (c)(15).

(h) ***Process unit equipment affected facility.*** To achieve initial compliance with the GHG and VOC standards for process unit equipment affected facilities as required by § 60.5400b, you must comply with paragraphs (h)(1) through (4) and (h)(11) through (15) of this section, unless you meet and comply with the exception in § 60.5402b(b), (e), or (f) or meet the exemption in § 60.5402b(c). If you comply with the GHG and VOC standards for process unit equipment affected facilities using the alternative standards in § 60.5401b, you must comply with paragraphs (h)(5) through (15) of this section, unless you meet the exemption in § 60.5402b(b) or (c) or the exception in § 60.5402b(e) or (f).

(1) You must conduct monitoring for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor or light liquid service and connector in gas/vapor or light liquid service as required by § 60.5400b(b).

(2) You must conduct monitoring as required by § 60.5400b(c) for each pump in light liquid service.

(3) You must conduct monitoring as required by § 60.5400b(d) for each pressure relief device in gas/vapor service.

(4) You must comply with the equipment requirements for each open-ended valve or line as required by § 60.5400b(e).

(5) You must conduct monitoring for each pump in light liquid service as required by § 60.5401b(b).

(6) You must conduct monitoring for each pressure relief device in gas/vapor service as required by § 60.5401b(c).

(7) You must comply with the equipment requirements for each open-ended valve or line as required by § 60.5401b(d).

(8) You must conduct monitoring for each valve in gas/vapor or light liquid service as required by § 60.5401b(f).

(9) You must conduct monitoring for each pump, valve, and connector in heavy liquid service and each pressure relief device in light liquid or heavy liquid service as required by § 60.5401b(g).

(10) You must conduct monitoring for each connector in gas/vapor or light liquid service as required by § 60.5401b(h).

(11) For each pump equipped with a dual mechanical seal system that degasses the barrier fluid reservoir to a process or a control device, each pump which captures and transports leakage from the seal or seals to a process or a control device, or each pressure relief device which captures and transports leakage through the pressure relief device to a process or a control device, you must meet the requirements of paragraph (h)(11)(i) through (vi) of this section.

(i) Reduce methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of § 60.5413b or route to a process.

(ii) Install a closed vent system that meets the requirements of § 60.5411b(a) and (c) to capture all emis equipped with a dual mechanical seal system that degasses the barrier fluid reservoir, each pump wh transports leakage from the seal or seals, or each pressure relief device which captures and transport pressure relief device and route all emissions to a process or to a control device that meets the condi 60.5412b.

(iii) If routing to a control device, conduct an initial performance test as required in § 60.5413b within 180 or by May 7, 2024, whichever date is later, or install a control device tested under § 60.5413b(d) which 60.5413b(d)(11) and (e), and you must comply with the continuous compliance requirements of § 60.

(iv) Conduct the initial inspections of the closed vent system and bypasses, if applicable, as required in §

(v) Install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) t

(vi) Maintain the records as required by § 60.5420b(c)(8) and (c)(10) through (c)(13), as applicable and su required by § 60.5420b(b)(11) through (13), as applicable.

(12) You must tag and repair each identified leak as required in § 60.5400b(h) or § 60.5400b(i), as applicable.

(13) You must submit the notice required by § 60.5420b(a)(1).

(14) You must submit the initial semiannual report and subsequent semiannual report as required by § 60.5422

(15) You must maintain the records specified by § 60.5421b.

(i) ***Sweetening unit affected facility.*** To achieve initial compliance with the SO_2 standard for your sweetening unit af by § 60.5405b, you must comply with paragraphs (i)(1) through (14) of this section.

(1) You must conduct an initial performance test as required by § 60.8 and according to the requirements of §

(2) You must determine the minimum required initial reduction efficiency of SO_2 emissions (Z_i) as required by §

(3) You must determine the emission reduction efficiency (R) achieved by your sulfur reduction technology usi 60.5406b(c)(1) through (4).

(4) You must demonstrate compliance with the standard as required by § 60.5405b(a) by comparing the minin emission reduction efficiency (Z_i) to the emission reduction efficiency achieved by the sulfur recovery tech be greater than or equal to Z_i.

(5) You must install, calibrate, maintain, and operate monitoring devices or perform measurements to determi sulfur product, the H_2S concentration, the average acid gas flow rate, and the sulfur feed rate in accordanc

(6) You must determine the required SO_2 emissions reduction efficiency each 24-hour period in accordance wi (e), as applicable.

(7) You must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors in 60.5407b(b), (f), and (g), if you use an oxidation control system or a reduction control system followed by a

(8) You must continuously operate the incineration device if you use an oxidation control system, or a reductio followed by an incineration device.

(9) You must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission compounds in accordance with § 60.5407b(c), (f), and (g), if you use a reduction control system not follow device.

(10) You must submit the notification required by § 60.5420b(a)(1).

(11) You must submit the initial annual report required by § 60.5423b(b).

(12) You must submit the performance test report in accordance with the requirements of § 60.5420b(b)(12).

(13) You must submit the annual excess emissions reports required by § 60.5423b(d), if applicable.

(3) If you use a control device to reduce emissions, you must equip each storage vessel in the storage vessel affected facility with a cover that meets the requirements of § 60.5411b(b), install a closed vent system that meets the requirements of § 60.5411b(a) and (c) to capture all emissions from the storage vessel affected facility, and route all emissions to a control device that meets the conditions specified in § 60.5412b. If you route emissions to a process, you must equip each storage vessel in the storage vessel affected facility with a cover that meets the requirements of § 60.5411b(b), install a closed vent system that meets the requirements of § 60.5411b(a) and (c) to capture all emissions from the storage vessel affected facility, and route all emissions to a process.

(4) If you use a control device to reduce emissions, you must conduct an initial performance test as required in § 60.5413b within 180 days after initial startup or within 180 days of May 7, 2024, whichever date is later, or install a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e), and you must comply with the continuous compliance requirements of § 60.5415b(f).

(5) You must conduct the initial inspections of the closed vent system and bypasses, if applicable, as required in § 60.5416b(a) and (b).

(6) You must install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) through (i), as applicable.

(7) You must maintain the records as required by § 60.5420b(c)(8) through (13), as applicable and submit the reports as required by § 60.5420b(b)(11) through (13), as applicable.

(8) You must submit the initial annual report for your storage vessel affected facility required by § 60.5420b(b)(1) and (8).

(9) You must maintain the records required for your storage vessel affected facility, as specified in § 60.5420b(c)(7) for each storage vessel affected facility.

(10) For each storage vessel affected facility that complies by using a floating roof, you must meet the requirements of § 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in subpart Kb of this part. You must submit a statement that you are complying with § 60.112b(d)(a)(1) or (2) in accordance with § 60.5395b(b)(2) with the initial annual report specified in § 60.5420b(b)(1) and (8).

(k) ***Fugitive emission components affected facility.*** To achieve initial compliance with the GHG and VOC standards for fugitive emissions components affected facilities as required by § 60.5397b, you must comply with paragraphs (k)(1) through (5) of this section.

(1) You must develop a fugitive emissions monitoring plan as required in § 60.5397b(b), (c), and (d).

(2) You must conduct an initial monitoring survey as required in § 60.5397b(e) and (f).

(3) You must repair each identified source of fugitive emissions for each affected facility as required in § 60.5397b(h).

(4) You must submit the initial annual report for each fugitive emissions components affected facility as required in § 60.5420b(b)(1) and (9).

(5) You must maintain the records specified in § 60.5420b(c)(14).

§ 60.5411b What additional requirements must I meet to determine initial compliance for my covers and closed vent systems?

For each cover or closed vent system at your well, centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, and process unit equipment affected facilities, you must comply with the applicable requirements of paragraphs (a) through (c) of this section.

(a) ***Closed vent system requirements.***

(1) Reciprocating compressor rod packing, process controllers, and pumps. You must design the closed vent system to capture and route all gases, vapors, and fumes to a process.

(2) Associated gas wells, centrifugal compressors, process controllers in Alaska, pumps complying with § 60.5393b(b)(1), storage vessels, and process unit equipment. You must design the closed vent system to capture and route all gases, vapors, and fumes to a process or a control device that meets the requirements specified in § 60.5412b(a) through (d) of this section. For pumps complying with § 60.5393b(b)(3), you must design the closed vent system to capture and route all gases, vapors, and fumes to a control device that meets the requirements specified in § 60.5412b(a) through (d) of this section.

(3) You must design and operate the closed vent system with no identifiable emissions as demonstrated by § 60.5416b(a) and (b).

(4) Bypass devices. You must meet the requirements specified in paragraphs (a)(4)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or being routed to a process.

(i) Except as provided in paragraph (a)(4)(ii) of this section, you must comply with either paragraph (a)(4)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device. The flow indicator must be capable of taking periodic readings as specified in § 60.5416b(a)(4)(i) and sound an alarm, or initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process, and sent to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420b(c)(10).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (a)(4)(i) of this section.

(b) ***Cover requirements for storage vessels and centrifugal compressors, and reciprocating compressors.***

(1) The cover and all openings on the cover (*e.g.,* access hatches, sampling ports, pressure relief devices and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or centrifugal compressor wet seal fluid degassing system, or reciprocating compressor rod packing emissions collection system.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.,* covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (a) of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated and sealed under normal operating conditions, including such times when working, standing/breathing, and flash emissions may be generated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(4) You must design and operate the cover with no identifiable emissions as demonstrated by § 60.5416b(a) and (b), except when operated as provided in paragraphs (b)(2)(i) through (iii) of this section.

(c) ***Design requirements.***

(1) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all gases, vapors, and fumes from the affected facility are routed to the control device or process and that the control device or process is of sufficient design and capacity to accommodate all emissions from the affected facility. The assessment must be certified by a qualified professional engineer or an in-house engineer with expertise on the design and operation of the closed vent system in accordance with paragraphs (c)(1)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted, and this report was prepared pursuant to the requirements of subpart OOOOb of this part. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(ii) The assessment shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in paragraph (c)(1)(i) of this section.

§ 60.5412b What additional requirements must I meet for determining initial compliance of my control devices?

You must meet the requirements of paragraphs (a) and (b) of this section for each control device used to comply with the emissions standards for your well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment affected facility. If you use a carbon adsorption system as a control device to meet the requirements of paragraph (a)(2) of this section, you also must meet the requirements in paragraph (c) of this section.

(a) Each control device used to meet the emissions reduction standard in § 60.5377b(f) for your associated gas well at a well affected facility; § 60.5376b(g) for your well affected facility gas well that unloads liquids; § 60.5380b(a)(1) for your centrifugal compressor affected facility; § 60.5385b(d)(2) for your reciprocating compressor affected facility; § 60.5395b(a)(2) for your storage vessel affected facility; § 60.5390b(b)(3) for your process controller affected facility in Alaska; § 60.5393b(b)(1) for your pumps affected facility; or either § 60.5400b(f) or § 60.5401b(e) for your process equipment affected facility must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative to paragraphs (a)(1) through (a)(3) of this section, you may install a control device model tested under § 60.5413b(d), which meets the criteria in § 60.5413b(d)(11) and which meets the initial and continuous compliance requirements in § 60.5413b(e).

(1) Each enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with paragraph (a)(1)(i) of this section, meet one of the operating limits specified in paragraphs (a)(1)(ii) through (v) of this section, and except for boilers and process heaters meeting the requirements of paragraph (a)(1)(iii) of this section and catalytic vapor incinerators meeting the requirements of paragraph (a)(1)(v) of this section, meet the operating limits specified in paragraphs (a)(1)(vi) through (ix) of this section. Alternatively, the enclosed combustion device must meet the requirements specified in paragraph (d) of this section.

(i) You must reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater or reduce the concentration of total organic compounds (TOC) in the exhaust gases at the outlet to the device to a level equal to or less than 275 ppmv as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 60.5413b(b), with the exceptions noted in § 60.5413b(a).

(ii) For an enclosed combustion device for which you demonstrate during the performance test conducted under § 60.5413b(b) that combustion zone temperature is an indicator of destruction efficiency, you must operate at or above the minimum temperature established during the most recent performance test. During the performance test conducted under § 60.5413b(b), you must continuously record the temperature of the combustion zone and average the temperature for each test run. The established minimum temperature limit is the average of the test run averages.

(iii) For an enclosed combustion device which is a boiler or process heater, you must introduce the vent stream into the flame zone of the boiler or process heater and introduce the vent stream with the primary fuel or use the vent stream as the primary fuel.

(iv) For an enclosed combustion device other than those meeting the operating limits in paragraphs (a)(1)(ii), (iii), and (v) of this section, if the enclosed combustion device is unassisted or pressure-assisted, you must maintain the net heating value (NHV) of the gas sent to the enclosed combustion device at or above the applicable limits specified in paragraphs (a)(1)(iv)(A) and (B) of this section. If the enclosed combustion device is steam-assisted or air-assisted, you must meet the applicable limits specified in paragraphs (a)(1)(iv)(C) and (D) of this section, as appropriate.

(A) For enclosed combustion devices that do not use assist gas or pressure-assisted burner tips to promote mixing at the burner tip, 200 British thermal units (Btu) per standard cubic feet (Btu/scf).

(B) For enclosed combustion devices that use pressure-assisted burner tips to promote mixing at the burner tip, 800 Btu/scf.

(C) For steam-assisted and air-assisted enclosed combustion devices, maintain the combustion zone NHV (NHV_{cz}) at or above 270 Btu/scf.

(D) For enclosed combustion devices with perimeter assist air, maintain the NHV dilution parameter (NHV_{dil}) at or above 22 British thermal units per square foot (Btu/sqft). If the only assist air provided to the enclosed combustion control device is perimeter assist air intentionally entrained in lower and/or upper steam at the burner tip and the effective diameter is 9 inches or greater, you are only required to comply with the NHV_{cz} limit specified in paragraph (a)(1)(iv)(C) of this section.

(v) For an enclosed combustion device which is a catalytic vapor incinerator, you must operate the catalytic vapor incinerator at or above the minimum temperature of the catalyst bed inlet and at or above the minimum temperature differential between the catalyst bed inlet and the catalyst bed outlet established in accordance with § 60.5417b(f) and as determined in your performance test conducted in accordance with § 60.5413b(b).

(vi) Unless you have an enclosed combustion device with pressure-assisted burner tips to promote mixing at the burner tip, you must operate each enclosed combustion device at or below the maximum inlet gas flow rate established in accordance with § 60.5417b(f) and as determined in your performance test conducted in accordance with § 60.5413b(b).

(vii) You must operate the combustion control device at or above the minimum inlet gas flow rate established in accordance with § 60.5417b(f).

(viii) You must install and operate a continuous burning pilot or combustion flame. An alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit.

(ix) You must operate the enclosed combustion device with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test using section 11 of Method 22 of appendix A-7 to this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes or once the amount of time visible emissions is present has exceeded 1 minute, whichever time period is less. Alternatively, you may conduct visible emissions monitoring according to § 60.5417b(h). Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair, and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A-7 to this part visual observation as described in this paragraph or be monitored according to § 60.5417b(h).

(2) Each vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413b(b). As an alternative to the performance testing requirements of § 60.5413b(b), you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of § 60.5413b(c). For a condenser, you also must calculate the daily average condenser outlet temperature in accordance with § 60.5417b(e), and you must determine the condenser efficiency for the current operating day

using the daily average condenser outlet temperature and the condenser performance curve established in accordance with § 60.5417b(f)(2). You must determine the average TOC emission reduction in accordance with § 60.5415b(f)(1)(ix)(D). For a carbon adsorption system, you also must comply with paragraph (c) of this section.

(3) Each flare must be designed and operated according to the requirements specified in paragraphs (a)(3)(i) through (viii) of this section, as applicable. Alternatively, flares must meet the requirements specified in paragraph (d) of this section.

(i) For unassisted flares, you must maintain the NHV of the vent gas sent to the flare at or above 200 Btu/scf.

(ii) For flares that use pressure-assisted burner tips to promote mixing at the burner tip, you must maintain the NHV of the vent gas sent to the flare at or above 800 Btu/scf.

(iii) For steam-assisted and air-assisted flares, you must maintain the NHV_{cz} at or above 270 Btu/scf.

(iv) For flares with perimeter assist air, you must maintain the NHV_{dil} at or above 22 Btu/sqft. If the only assist air provided to the flare is perimeter assist air intentionally entrained in lower and/or upper steam at the flare tip and the effective diameter is 9 inches or greater, you are not required to comply with the NHV_{dil} limit.

(v) For flares other than pressure-assisted flares, you must demonstrate compliance with the flare tip velocity limits in § 60.18(b) according to § 60.5417b(d)(8)(iv). The maximum flare tip velocity limits do not apply for pressure-assisted flares.

(vi) You must operate the flare at or above the minimum inlet gas flow rate. The minimum inlet gas flow rate is established based on manufacturer recommendations.

(vii) You must operate the flare with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. You must conduct the compliance determination with the visible emission limits using Method 22 of appendix A-7 to this part, or you must monitor the flare according to § 60.5417b(h).

(viii) You must install and operate a continuous burning pilot or combustion flame. An alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit.

(b) You must operate each control device installed on your well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment affected facility in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of § 60.5417b(a) through (i), you must demonstrate compliance according to the requirements of § 60.5415b(f), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) of this section, you must comply with the requirements of paragraph (c)(1) of this section. If the carbon adsorption system is a regenerative-type carbon adsorption system, you also must comply with the requirements of paragraph (c)(2) of this section.

(1) You must manage the carbon in accordance with the requirements specified in paragraphs (c)(1)(i) and (ii) of this section.

(i) Following the initial startup of the control device, you must replace all carbon in the carbon adsorption system with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to § 60.5413b(c)(2) or (3). You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in § 60.5420b(c)(10) and (12).

(ii) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(1)(ii)(A) through (F) of this section.

(A) Regenerate or reactivate the spent carbon in a unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(B) Regenerate or reactivate the spent carbon in a unit equipped with an operating organic air emissions control in accordance with an emissions standard for VOC under another subpart in 40 CFR part 63 or this part.

(C) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE, and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(D) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE, and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(E) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(F) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(2) You must comply with the requirements of paragraph (c)(2)(i) through (iii) of this section for each regenerative-type carbon adsorption system.

(i) You must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle to demonstrate compliance with the total regeneration stream flow established in accordance with § 60.5413b(c)(2).

(ii) You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion, if your continuous parameter monitoring system is not equipped with a redundant flow sensor.

(iii) You must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. You must maintain the average carbon bed temperature above the temperature limit in established accordance with § 60.5413b(c)(2) during the carbon bed steaming cycle and below the carbon bed temperature established in in accordance with § 60.5413b(c)(2) after the regeneration cycle.

(d) To demonstrate that a flare or enclosed combustion device reduces methane and VOC in the gases vented to the device by 95.0 percent by weight or greater, as outlined in § 60.8(b), you may submit a request for an alternative test method. At a minimum, the request must follow the requirements outlined in paragraphs (d)(1) through (5) of this section.

(1) The alternative method must be capable of demonstrating continuous compliance with a combustion efficiency of 95.0 percent or greater or it must be capable of demonstrating continuous compliance with the following metrics:

(i) NHV_{cz} of 270 Btu/scf or greater.

(ii) NHV_{dil} of 22 Btu/sqft or greater, if the alternative test method will be used for enclosed combustion devices or flares with perimeter assist air.

(2) The alternative method must be validated according to Method 301 in appendix A of 40 CFR part 63 for each type of control device covered by the alternative test method (*e.g.,* air-assisted flare, unassisted enclosed combustion device) or the alternative test method must contain performance-based procedures and indicators to ensure self-validation.

(3) At a minimum the alternative test method must provide a reading for each successive 15-minute period.

(4) The alternative test method must be capable of documenting periods when the enclosed combustion device or flare operates with visible emissions. If the alternative test method cannot identify periods of visible emissions, you must conduct the inspections required by § 5417b(d)(8)(v).

(5) If the alternative test method demonstrates compliance with the metrics specified in paragraphs (d)(1)(i) and (ii) of this section instead of demonstrating continuous compliance with 95.0 percent or greater combustion efficiency, you must still install the pilot or combustion flame monitoring system required by § 60.5417b(d)(8)(i). If the alternative test method demonstrates continuous compliance with a combustion efficiency of 95.0 percent or greater, the requirement in § 60.5417b(d)(8)(i) no longer applies.

§ 60.5413b What are the performance testing procedures for control devices?

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump affected facilities complying with § 60.5393b(b)(1), or process unit equipment affected facility. You must demonstrate that a control device achieves the performance requirements of § 60.5412b(a)(1) or (2) using the performance test methods and procedures specified in this section. For condensers and carbon adsorbers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion device performance tests conducted by the manufacturer applicable to well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump affected facilities complying with § 60.5393b(b)(1), or process unit equipment affected facilities.

(a) ***Performance test exemptions.*** You are exempt from the requirements to conduct initial and periodic performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (6) of this section. You are exempt from the requirements to conduct an initial performance test if you use a control device described in paragraph (a)(7) of this section.

(1) A flare that is designed and operated in accordance with the requirements in § 60.5412b(a)(3). You must conduct the compliance determination using Method 22 of appendix A-7 to this part to determine visible emissions or monitor the flare according to § 60.5417b(h). The net heating value of the vent gas must be determined according to § 60.5417b(d)(8)(ii).

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H; you have submitted a Notification of Compliance under 40 CFR 63.1207(j) and comply with the

requirements of 40 CFR part 63, subpart EEE; or you comply with 40 CFR part 63, subpart EEE and will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in § 60.5420b(b)(12) for submitting the initial performance test report.

(5) A hazardous waste incinerator for which you have submitted a Notification of Compliance under 40 CFR 63.1207(j), or for which you will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in § 60.5420b(b)(12) for submitting the initial performance test report, and you comply with the requirements of 40 CFR part 63, subpart EEE.

(6) A control device for which performance test is waived in accordance with § 60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of § 60.5412b(a)(1)(i) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) ***Test methods and procedures.*** You must use the test methods and procedures specified in paragraphs (b)(1) through (4) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of § 60.5412b(a)(1) or (2). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section. Each performance test must consist of a minimum of 3 test runs. Each run must be at least 1 hour long.

(1) You must use Method 1 or 1A of appendix A-1 to this part, as appropriate, to select the sampling sites. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device and at the outlet of the final control device to determine compliance with a control device percent reduction requirement.

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with a TOC exhaust gas concentration limit.

(2) You must determine the gas volumetric flow rate using Method 2, 2A, 2C, or 2D of appendix A-2 to this part, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in § 60.5412b(a)(1)(i) or (a)(2), you must use Method 25A of appendix A-7 to this part. You must use Method 4 of appendix A-3 to this part to convert the Method 25A results to a dry basis. You must use the procedures in paragraphs (b)(3)(i) through (iii) of this section to calculate percent reduction efficiency.

(i) You must compute the mass rate of TOC using the following equations:

Equations 1 and 2 to paragraph (b)(3)(i)

$$E_i = K_2 C_i M_p Q_i$$

$$E_o = K_2 C_o M_p Q_o$$

Where:

E_i, E_o = Mass rate of TOC at the inlet and outlet of the control device, respectively, dry basis, kilograms per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 degrees Celsius.

C_i, C_o = Concentration of TOC, as propane, of the gas stream as measured by Method 25A of appendix A-7 to this part at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_p = Molecular weight of propane, 44.1 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.

(ii) You must calculate the percent reduction in TOC as follows:

Equation 3 to paragraph (b)(3)(ii)

$$R_{cd} = \frac{E_i - E_o}{E_i} \times 100\%$$

Where:

R_{cd} = Control efficiency of control device, percent.

E_i, = Mass rate of TOC at the inlet to the control device as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

E_o = Mass rate of TOC at the outlet of the control device, as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

(iii) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC across the device by comparing the TOC in all combusted vent streams and primary and secondary fuels with the TOC exiting the device, respectively.

(4) You must use Method 25A of appendix A-7 to this part to measure TOC, as propane, to determine compliance with the TOC exhaust gas concentration limit specified in § 60.5412b(a)(1)(i). You must determine the concentration in parts per million by volume on a wet basis and correct it to 3 percent oxygen. You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B of appendix A-2 to this part, ASTM D6522-20, or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (both incorporated by reference, see § 60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration. You must correct the TOC concentration for percent oxygen as follows:

Equation 4 to paragraph (b)(4)

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2m}} \right)$$

Where:
C_c = TOC concentration, as propane, corrected to 3 percent oxygen, parts per million by volume on a wet basis.
C_m = TOC concentration, as propane, parts per million by volume on a wet basis.
$\%O_{2m}$ = Concentration of oxygen, percent by volume as measured, wet.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) through (iii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in § 60.5420b(b)(12).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. If a control device is not operational at the time a performance test is due, you must conduct the performance test no later than 30 calendar days after returning the control device to service. You must submit the periodic performance test results as specified in § 60.5420b(b)(12).

(iii) If the initial performance test was conducted by the manufacturer under paragraph (d) of this section, you must conduct the first periodic performance test no later than 60 months after initial installation and startup of the control device. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test. If a control device is not operational at the time a performance test is due, you must conduct the performance test no later than 30 calendar days after returning the control device to service. You must submit the periodic performance test results as specified in § 60.5420b(b)(12).

(c) ***Control device design analysis to meet the requirements of § 60.5412b(a)(2).***

(1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature and must 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.

(2) For a regenerable carbon adsorption system, the design analysis shall include 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 the carbon beds, design total regeneration stream 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 the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flow rate, relative humidity and temperature and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems shall incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

(d) ***Performance testing for combustion control devices—manufacturers' performance test.***

(1) This paragraph (d) applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three 1-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90-100 percent of maximum design rate (fixed rate).

(ii) 70-100-70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10- to 15-minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30-70-30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10- to 15-minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0-30-0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10- to 15-minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) and (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with Method 2A of appendix A-1 of this part (or other approved procedure) to measure inlet gas flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet flow rate must be determined using Method 2A to appendix A-1 of this part. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) and (ii) of this section.

(i) At the inlet gas sampling location, securely connect a fused silica-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of each test run and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945-03(R2010) (incorporated by reference, see § 60.17).

(B) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945-03(R2010) (incorporated by reference, see § 60.17).

(C) Higher heating value using ASTM D3588-98(R2003) or ASTM D4891-89(R2006) (both incorporated by reference, see § 60.17).

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) and (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using Method 1 of appendix A-1 to this part for determining flow measurement traverse point location, and Method 2 of appendix A-1 to this part for measuring duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the moisture test required by Method 4 of appendix A-3 to this part following the procedure specified in (d)(7)(i)(A) and (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC-TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) and (D) of this section.

(A) Collect the integrated sample throughout the entire test and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC-TCD calibration procedure in Method 3C of appendix A-2 to this part must be modified as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using Method 4 of appendix A-3 to this part. Traverse both ports with the sampling train required by Method 4 of appendix A-3 to this part during each test run. Ambient air must not be introduced into the integrated bag sample required by Method 3C of appendix A-2 to this part during the port change.

(iii) Excess air must be determined using resultant data from the Method 3C tests and Method 3B of appendix A-2 to this part, equation 3B-1 in Method 3B, or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference, see § 60.17).

(8) Carbon monoxide must be determined using Method 10 of appendix A-4 to this part. Run the test simultaneously with Method 25A of appendix A-7 to this part using the same sampling points. An instrument range of 0-10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified by in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using Method 25A of appendix A-7 to this part, except that the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test run.

(ii) A valid test must consist of three Method 25A tests, each no less than 60 minutes in duration.

(iii) A 0 to 10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0 to 30 ppmvw (as propane) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA-600/R-12/531—"EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," (incorporated by reference, see § 60.17).

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO_2, as measured by Method 3C of appendix A-2 to this part. You must use the following equation for this diluent concentration correction:

Equation 5 to paragraph (d)(9)(vi)

$$C_{corr} = C_{meas}\left(\frac{3}{CO_{2meas}}\right)$$

Where:
C_{meas} = The measured concentration of the pollutant.
CO_{2meas} = The measured concentration of the CO_2 diluent.
3 = The corrected reference concentration of CO_2 diluent.
C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using Method 22 of appendix A-7 to this part. The test must be perf during each test run. A digital color photograph of the exhaust point, taken from the position of the observe date and time, must be taken once per test run and the 12 photos included in the test report specified in pa section.

(11)

(i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this must be reported in the test report required by paragraph (d)(12) of this section.

(A) Results from Method 22 of appendix A-7 to this part determined under paragraph (d)(10) of this of visible emissions.

(B) Average results from Method 25A of appendix A-7 to this part determined under paragraph (d)(9) or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 1(to 3.0 percent CO_2.

(D) Excess air determined under paragraph (d)(7) of this section equal to or greater than 150 percen

(ii) The manufacturer must determine a minimum inlet gas flow rate above which each control device mo achieve the criteria in paragraph (d)(11)(iii) of this section. The manufacturer must determine a maxir which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(11 minimum and maximum inlet gas flow rate must be included in the test report required by paragraph

(iii) A manufacturer must demonstrate a destruction efficiency of at least 95.0 percent for THC, as propar model that demonstrates a destruction efficiency of 95.0 percent for THC, as propane, will meet the c 95.0 percent destruction of VOC and methane required under this subpart.

(12) The owner or operator of a combustion control device model tested under this paragraph (d)(12) must sub in paragraphs (d)(12)(i) through (vi) of this section for each test run in the test report required by this sectio 60.5420b(b)(13). Owners or operators who claim that any of the performance test information being subm business information (CBI) must submit a complete file including information claimed to be CBI to the OAC preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Trans online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office a *oaqpscbi@epa.gov* and should include clear CBI markings and be flagged to the attention of the Leader, Me If assistance is needed with submitting large electronic files that exceed the file size limit for email attachr have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link. If you can electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Control Officer and Measurement Policy Group Leader, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. E Carolina 27711. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings the outer envelope. The same file with the CBI omitted must be submitted to *Oil_and_Gas_PT@EPA.GOV*.

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the minimum and maximum allowabl

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) ***Initial and continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.*** This paragraph (e) applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance criteria in paragraph (d)(11) of this section by installing a device tested under paragraph (d) of this section, complying with the criteria specified in paragraphs (e)(1) through (10) of this section, maintaining the records specified in § 60.5420b(c)(11) and submitting the report specified in § 60.5420b(b)(11)(v) and (13).

(1) The inlet gas flow rate must be equal to or greater than the minimum inlet gas flow rate and equal to or less than the maximum inlet gas flow rate specified by the manufacturer.

(2) A pilot or combustion flame must be present at all times of operation. An alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of Method 22 of appendix A-7 to this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes or once the amount of time visible emissions is present has exceeded 1 minute, whichever time period is less. Alternatively, you may conduct visible emissions monitoring according to § 60.5417b(h).

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass a visual observation according to Method 22 of appendix A-7 to this part as described in paragraph (e)(3) of this section or be monitored according to § 60.5417b(h).

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following website: *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry.*

(7) Ensure that each enclosed combustion device is maintained in a leak free condition.

(8) Operate each control device following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(9) Install and operate the continuous parameter monitoring systems in accordance with § 60.5417b(a) and (c) through (i).

(10) Comply with the applicable NHV limit specified in § 60.5412b(a)(1)(iv).

§ 60.5415b How do I demonstrate continuous compliance with the standards for each of my affected facilities?

(a) ***Well completion standards for well affected facility.*** For each well completion operation at your well affected facility, you must demonstrate continuous compliance with the requirements of § 60.5375b by submitting the annual report required by § 60.5420b(b)(1) and (2) and maintaining the records for each completion operation specified in § 60.5420b(c)(1).

(b) ***Gas well liquids unloading standards for well affected facility.*** For each well liquids unloading operation at your well affected facility, you must demonstrate continuous compliance with the requirements of § 60.5376b by submitting the annual report information specified in § 60.5420b(b)(1) and (3) and maintaining the records for each well liquids unloading event specified in § 60.5420b(c)(2). For each gas well liquids unloading well affected facility that complies with the requirements of § 60.5376b(g), you must route emissions to a control device through a closed vent system and continuously comply with the closed vent requirements of § 60.5416b. You also must comply with the requirements specified in paragraph (f) of this section and maintain the records in § 60.5420b(c)(8), (10) and (12).

(c) ***Associated gas well standards for well affected facility.*** For each associated gas well, you must demonstrate continuous compliance with the requirements of § 60.5377b by submitting the reports required by § 60.5420b(b)(1) and (4) and maintaining the records specified in § 60.5420b(c)(3). For each associated gas well that complies with the requirements of § 60.5377b(d) or (f), you must route emissions to a control device through a closed vent system and continuously comply with the closed vent requirements of § 60.5416b. You also must comply with the requirements specified in paragraph (f) of this section and maintain the records in § 60.5420b(c)(8), (10) and (12).

(d) ***Centrifugal compressor affected facility.*** For each wet seal centrifugal compressor affected facility complying with § 60.5380b(a)(1) and (2), or with § 60.5380b(a)(3) by routing emissions to a control device or to a process, you must demonstrate continuous compliance according to paragraph (d)(1) and paragraphs (d)(3) and (4) of this section. For each self-contained wet seal centrifugal compressor complying with the requirements in § 60.5380b(a)(4), you must demonstrate continuous compliance according to paragraphs (d)(2) through (4) of this section. For each centrifugal compressor on the Alaska North Slope equipped with sour seal oil separator and capture system, complying with the requirements of § 60.5380b(a)(5), you must demonstrate continuous compliance according to paragraphs (d)(2) through (4) of this section. For each dry seal centrifugal compressor complying with the requirements in § 60.5380b(a)(6), you must demonstrate continuous compliance according to paragraphs (d)(2) through (4) of this section.

(1) For each wet seal centrifugal compressor affected facility complying by routing emissions to a control device or to a process, you must operate the wet seal emissions collection system to route emissions to a control device or a process through a closed vent system and continuously comply with the cover and closed vent requirements of § 60.5416b. If you comply with § 60.5380b(a)(2) by using a control device, you also must comply with the requirements in paragraph (f) of this section.

(2) You must maintain volumetric flow rate at or below the flow rates specified in § 60.5380b(a)(5) for you centrifugal compressor and you must conduct the required volumetric flow rate measurement of your self-contained wet seal centrifugal compressor, Alaska North Slope centrifugal compressor equipped with sour seal oil separator and capture system, or dry seal centrifugal compressor in accordance with § 60.5380b(a)(6) on or before 8,760 hours of operation after your last volumetric flow rate measurement which demonstrates compliance with the volumetric flow rate specified in § 60.5380b(a)(5) for you centrifugal compressor.

(3) You must submit the annual reports as required in § 60.5420b(b)(1), (5), and (11)(i) through (iv), as applicable.

(4) You must maintain records as required in § 60.5420b(c)(4), (8) through (10), and (12), as applicable.

(e) ***Pump affected facility.*** To demonstrate continuous compliance with the GHG and VOC standards for your pump affected facility as required by § 60.5393b, you must comply with paragraphs (e)(1) through (3) of this section.

(1) For pump affected facilities complying with the requirements of § 60.5393b(a) by routing emissions to a process, and for pump affected facilities complying with the requirements of § 60.5393b(b)(2), or (3), you must continuously comply with the closed vent requirements of § 60.5416b. If you comply with § 60.5393b(b)(3), you also must comply with the requirements in paragraph (f) of this section.

(2) You must submit the annual reports for your pump affected facility as required in § 60.5420b(b)(1), (10), and (11)(i) through (iv), as applicable.

(3) You must maintain the records for your pump affected facility as specified in § 60.5420b(c)(8), (10), (12), and (15), as applicable.

(f) ***Additional continuous compliance requirements for well, centrifugal compressor, reciprocating compressor, process controllers in Alaska, storage vessel, process unit equipment, or pump affected facilities.*** For each associated gas well, each gas well that conducts liquids unloading, each centrifugal compressor affected facility, each reciprocating compressor affected facility, each process controller affected facility in Alaska, each storage vessel affected facility, each process unit equipment affected facility, and each pump affected facility referenced to this paragraph from either paragraph (b), (c), (d)(1), (e)(1), (g), (h)(2)(iv), (i) or (j) of this section, you must also install monitoring systems as specified in § 60.5417b, demonstrate continuous compliance according to paragraph (f)(1) of this section, maintain the records in paragraph (f)(2) of this section, and comply with the reporting requirements specified in paragraph (f)(3) of this section.

(1) You must demonstrate continuous compliance with the control device performance requirements of § 60.5412b(a) using the procedures specified in paragraphs (f)(1)(i) through (viii) of this section and conducting the monitoring as required by § 60.5417b. If you use a condenser as the control device to achieve the requirements specified in § 60.5412b(a)(2), you may demonstrate compliance according to paragraph (f)(1)(ix) of this section. You may switch between compliance with paragraphs (f)(1)(i) through (viii) of this section and compliance with paragraph (f)(1)(ix) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, following the change. If you use an enclosed combustion device or a flare as the control device, you must also conduct the monitoring required in paragraph (f)(1)(x) of this section. If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), you must use the procedures in paragraph (f)(1)(xi) of this section in lieu of the procedures in paragraphs (f)(1)(i) through (viii) of this section, but you must still conduct the monitoring required in paragraph (f)(1)(x) of this section.

(i) You must operate below (or above) the site-specific maximum (or minimum) parameter value established according to the requirements of § 60.5417b(f)(1). For flares, you must operate above the limits specified in paragraphs (f)(1)(vii)(B) of this section.

(ii) You must calculate the average of the applicable monitored parameter in accordance with § 60.5417b(e).

(iii) Compliance with the operating parameter limit is achieved when the average of the monitoring parameter value calculated under paragraph (f)(1)(ii) of this section is either equal to or greater than the minimum parameter value or equal to or less than the maximum parameter value established under paragraph (f)(1)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in § 60.5413b(d), compliance with the operating parameter limit is achieved when the criteria in § 60.5413b(e) are met.

(iv) You must operate the continuous monitoring system required in § 60.5417b(a) at all times the affected source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities, including, as applicable, system accuracy audits and required zero and span adjustments. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements.

(vii) If you use an enclosed combustion device to meet the requirements of § 60.5412b(a)(1) and you demonstrate compliance using the test procedures specified in § 60.5413b(b), or you use a flare designed and operated in accordance with § 60.5412b(a)(3), you must comply with the applicable requirements in paragraphs (f)(1)(vii)(A) through (E) of this section.

(A) For each enclosed combustion device which is not a catalytic vapor incinerator and for each flare, you must comply with the requirements in paragraphs (f)(1)(vii)(A)(*1*) through (*4*) of this section.

(*1*) A pilot or combustion flame must be present at all times of operation. An alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit.

(*2*) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of Method 22 of appendix A-7 to this part, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes or once the amount of time visible emissions is present has exceeded 1 minute, whichever time period is less. Alternatively, you may conduct visible emissions monitoring according to § 60.5417b(h).

(*3*) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(*4*) Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A-7 to this part visual observation as described in paragraph (f)(1)(vii)(D) of this section or be monitored according to § 60.5417b(h).

(B) For flares, you must comply with the requirements in paragraphs (f)(1)(vii)(B)(*1*) through (*6*) of this section.

(*1*) For unassisted flares, maintain the NHV of the gas sent to the flare at or above 200 Btu/scf.

(*2*) If you use a pressure assisted flare, maintain the NHV of gas sent to the flare at or above 800 Btu/scf.

(*3*) For steam-assisted and air-assisted flares, maintain the NHV_{cz} at or above 270 Btu/scf.

(*4*) For flares with perimeter assist air, maintain the NHV_{dil} at or above 22 Btu/sqft. If the only assist air provided to the flare is perimeter assist air intentionally entrained in lower and/or upper steam at the flare tip and the effective diameter is 9 inches or greater, you are not required to comply with the NHV_{dil} limit.

(*5*) Unless you use a pressure-assisted flare, maintain the flare tip velocity below the applicable limits in § 60.18(b).

(*6*) Maintain the total gas flow to the flare above the minimum inlet gas flow rate. The minimum inlet gas flow rate is established based on manufacturer recommendations.

(C) For enclosed combustion devices for which, during the performance test conducted under § 60.5413b(b), the combustion zone temperature is not an indicator of destruction efficiency, you must comply with the requirements in paragraphs (f)(1)(vii)(C)(*1*) through (*5*) of this section, as applicable.

(*1*) Maintain the total gas flow to the enclosed combustion device at or above the minimum inlet gas flow rate and at or below the maximum inlet flow rate for the enclosed combustion device established in accordance with § 60.5417b(f).

(*2*) For unassisted enclosed combustion devices, maintain the NHV of the gas sent to the enclosed combustion device at or above 200 Btu/scf.

(*3*) For enclosed combustion devices that use pressure-assisted burner tips to promote mixing at the burner tip, maintain the NHV of the gas sent to the enclosed combustion device at or above 800 Btu/scf.

(*4*) For steam-assisted and air-assisted enclosed combustion devices, maintain the NHV_{cz} at or above 270 Btu/scf.

(*5*) For enclosed combustion devices with perimeter assist air, maintain the NHV_{dil} at or above 22 Btu/sqft. If the only assist air provided to the enclosed combustion device is perimeter assist air intentionally entrained in lower and/or upper steam at the flare tip and the effective diameter is 9 inches or greater, you are not required to comply with the NHV_{dil} limit.

(D) For enclosed combustion devices for which, during the performance test conducted under § 60.5413b(b), the combustion zone temperature is demonstrated to be an indicator of destruction efficiency, you must comply with the requirements in paragraphs (f)(1)(vii)(D)(*1*) and (*2*) of this section.

(*1*) Maintain the temperature at or above the minimum temperature established during the most recent performance test. The minimum temperature limit established during the most recent performance test is the average temperature recorded during each test run, averaged across the 3 test runs (average of the test run averages).

(*2*) Maintain the total gas flow to the enclosed combustion device at or above the minimum inlet gas flow rate and at or below the maximum inlet flow rate for the enclosed combustion device established in accordance with § 60.5417b(f).

(E) For catalytic vapor incinerators you must operate the catalytic vapor incinerator at or above the minimum temperature of the catalyst bed inlet and at or above the minimum temperature differential between the catalyst bed inlet and the catalyst bed outlet established in accordance with § 60.5417b(f).

(viii) If you use a carbon adsorption system as the control device to meet the requirements of § 60.5412b(a)(2), you must demonstrate compliance by the procedures in paragraphs (f)(1)(viii)(A) and (B) of this section, as applicable.

(A) If you use a regenerative-type carbon adsorption system, you must comply with paragraphs (f)(1)(viii)(A)(*1*) through (*4*) of this section.

(*1*) You must maintain the average regenerative mass flow or volumetric flow to the carbon adsorber during each bed regeneration cycle above the limit established in in accordance with § 60.5413b(c)(2).

(*2*) You must maintain the average carbon bed temperature above the temperature limit established in accordance with § 60.5413b(c)(2) during the carbon bed steaming cycle and below the carbon bed temperature established in in accordance with § 60.5413b(c)(2) after the regeneration cycle.

(*3*) You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your continuous parameter monitoring system is not equipped with a redundant flow sensor.

(*4*) You must replace all carbon in the carbon adsorption system with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to § 60.5413b(c)(2).

(B) If you use a nonregenerative-type carbon adsorption system, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to § 60.5413b(c)(3).

(ix) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in § 60.5412b(a)(2), you must demonstrate compliance using the procedures in paragraphs (f)(1)(ix)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to § 60.5417b(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with § 60.5417b(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (f)(1)(ix)(B) of this section and the condenser performance curve established under paragraph (f)(1)(ix)(A) of this section.

(D) Except as provided in paragraphs (f)(1)(ix)(D)(*1*) and (*2*) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (f)(1)(ix)(C) of this section.

(*1*) After the compliance dates specified in § 60.5370b(a), if you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation after the compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(*2*) After 120 days and no more than 364 days of operation after the compliance date specified in § 60.5370b(a), you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (f)(1)(ix)(D) of this section is equal to or greater than 95.0 percent.

(x) During each inspection conducted using an OGI camera under § 60.5397b and during each periodic screening event or each inspection conducted using an OGI camera under § 60.5398b, you must observe each enclosed combustion device and flare to determine if it is operating properly. You must determine whether there is a flame present and whether any uncontrolled emissions from the control device are visible with the OGI camera or the technique used to conduct the periodic screening event. During each inspection conducted under § 60.5397b using AVO, you must observe each enclosed combustion device and flare to determine if it is operating properly. Visually confirm that the pilot or combustion flame is lit and that the pilot or combustion flame is operating properly.

(xi) If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), you must comply with paragraphs (f)(1)(xi)(A) through (E) of this section.

(A) You must maintain the combustion efficiency at or above 95.0 percent. Alternatively, if the alternative test method does not directly monitor combustion efficiency, you must comply with the applicable requirements in paragraphs (f)(1)(xi)(A)(*1*) and (*2*) of this section.

(*1*) Maintain the NHV_{cz} at or above 270 Btu/scf.

(*2*) For flares or enclosed combustion devices with perimeter assist air, maintain the NHV_{dil} at or above 22 Btu/sqft. If the only assist air provided to the flare or enclosed combustion device is perimeter assist air intentionally entrained in lower and/or upper steam at the flare tip and the effective diameter is 9 inches or greater, you are only required to comply with the NHV_{cz} limit specified in paragraph (f)(1)(xi)(A)(*1*) of this section.

(B) You must calculate the value of the applicable monitored metric(s) in accordance with the approved alternative test method. Compliance with the limit is achieved when the calculated values are within the range specified in paragraph (f)(1)(xi)(A) of this section.

(C) You must conduct monitoring using the alternative test method at all times the affected source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities, including, as applicable, system accuracy audits and required zero and span adjustments. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(D) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report values to demonstrate compliance with the limits specified in paragraph (f)(1)(xi)(A) of this section. You must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(E) Failure to collect required data is a deviation of the monitoring requirements.

(2) You must maintain the records as specified in § 60.5420b(c)(11) and (13).

(3) You must comply with the reporting requirements in § 60.5420b(b)(11) through (13).

(g) ***Reciprocating compressor affected facility.*** For each reciprocating compressor affected facility complying with § 60.5385b(a) through (c), you must demonstrate continuous compliance according to paragraphs (g)(1), (5), and (6) of this section. For each reciprocating compressor affected facility complying with § 60.5385b(d)(1) or (2), you must demonstrate continuous compliance according to paragraphs (g)(2), (5) and (6) of this section. For each reciprocating compressor affected facility complying with § 60.5385b(d)(3), you must demonstrate continuous compliance according to paragraphs (g)(3) through (6) of this section.

(1) You must maintain the volumetric flow rate at or below 2 scfm per cylinder (or at or below the combined volumetric flow rate determined by multiplying the number of cylinders by 2 scfm), and you must conduct the required volumetric flow rate measurement of your reciprocating compressor rod packing vents in accordance with § 60.5385b(b) on or before 8,760 hours of operation after your last volumetric flow rate measurement which demonstrated compliance with the applicable volumetric flow rate.

(2) You must operate the rod packing emissions collection system to route emissions to a control device or to a process through a closed vent system and continuously comply with the cover and closed vent requirements of § 60.5416b. If you comply with § 60.5385b(d) by using a control device, you also must comply with the requirements in paragraph (f) of this section.

(3) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility since initial startup, since May 7, 2024, since the previous flow rate measurement, or since the date of the most recent reciprocating compressor rod packing replacement, whichever date is latest.

(4) You must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 8,760 hours.

(5) You must submit the annual reports as required in § 60.5420b(b)(1), (6), and (11)(i) through (iv), as applicable.

(6) You must maintain records as required in § 60.5420b(c)(5), (8) through (10), and (12), as applicable.

(h) ***Process controller affected facility.*** To demonstrate continuous compliance with GHG and VOC emission standards for your process controller affected facility as required by § 60.5390b, you must comply with paragraphs (h)(1) through (4) of this section, as applicable.

(1) You must demonstrate that your process controller affected facility does not emit any VOC or methane to the atmosphere by meeting the requirements of paragraphs (h)(1)(i) or (ii) of this section.

(i) If you comply by routing the emissions to a process, you must comply with the closed vent system inspection and monitoring requirements of § 60.5416b.

(ii) If you comply by using a self-contained natural gas-driven process controller, you must conduct the no identifiable emissions inspections required by § 60.5416b(b).

(2) For each process controller affected facility located at a site in Alaska that does not have access to electrical power and that complies by reducing methane and VOC emissions from all controllers in the process controller affected facility by 95.0 percent in accordance with § 60.5390b(b)(3), you must comply with the closed vent requirements of § 60.5416b and the requirements in paragraph (f) of this section for the control device.

(3) You must submit the annual report for your process controller as required in § 60.5420b(b)(1), (7), and (11)(i) through (iv), as applicable.

(4) You must maintain the records as specified in § 60.5420b(c)(6), (8), (10), and (12) for each process controller affected facility, as applicable.

(i) ***Storage vessel affected facility.*** For each storage vessel affected facility, you must demonstrate continuous compliance with the requirements of § 60.5395b according to paragraphs (i)(1) through (10) of this section, as applicable.

(1) For each storage vessel affected facility complying with the requirements of § 60.5395b(a)(2), you must demonstrate continuous compliance according to paragraphs (i)(5), (9) and (10) of this section.

(2) For each storage vessel affected facility complying with the requirements of § 60.5395b(a)(3), you must demonstrate continuous compliance according to paragraphs (i)(2)(i), (ii), or (iii) of this section, as applicable, and (i)(9) and (10) of this section.

(i) You must maintain the uncontrolled actual VOC emissions at less than 4 tpy and the uncontrolled actual methane emissions at less than 14 tpy from the storage vessel affected facility.

(ii) You must comply with paragraph (i)(5) of this section as soon as liquids from the well are routed to the storage vessel affected facility following fracturing or refracturing according to the requirements of § 60.5395b(a)(3)(i).

(iii) You must comply with paragraph (i)(5) of this section within 30 days of the monthly determination according to the requirements of § 60.5395b(a)(3)(ii), where the monthly emissions determination indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility.

(3) For each storage vessel affected facility or portion of a storage vessel affected facility removed from service, you must demonstrate compliance with the requirements of § 60.5395b(c)(1) by complying with paragraphs (i)(6), (7), (9), and (10) of this section.

(4) For each storage vessel affected facility or portion of a storage vessel affected facility returned to service, you must demonstrate compliance with the requirements of § 60.5395b(c)(1) by complying with paragraphs (i)(8) through (10) of this section.

(5) For each storage vessel affected facility, you must comply with paragraphs (i)(5)(i) and (ii) of this section.

(i) You must reduce VOC emissions as specified in § 60.5395b(a)(2).

(ii) For each control device installed to meet the requirements of § 60.5395b(a)(2), you must demonstrate continuous compliance with the performance requirements of § 60.5412b for each storage vessel affected facility using the procedure specified in paragraphs (i)(5)(ii)(A) and (i)(5)(ii)(B) of this section. When routing emissions to a process, you must demonstrate continuous compliance as specified in paragraph (i)(5)(ii)(A) of this section.

(A) You must comply with § 60.5416b for each cover and closed vent system.

(B) You must comply with the requirements specified in paragraph (f) of this section.

(6) You must completely empty and degas each storage vessel, such that each storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. For a portion of a storage vessel affected facility to be removed from service, you must completely empty and degas the storage vessel(s), such that the storage vessel(s) no longer contains crude oil, condensate, produced water, or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage, or in pools due to floor irregularity is considered to be completely empty.

(7) You must disconnect the storage vessel(s) from the tank battery by isolating the storage vessel(s) from the tank battery such that the storage vessel(s) is no longer manifolded to the tank battery by liquid or vapor transfer.

(8) You must determine the affected facility status of a storage vessel returned to service as provided in § 60.5365b(e)(6).

(9) You must submit the annual reports as required by § 60.5420b(b)(1), (8), and (11)(i) through (iv).

(10) You must maintain the records as required by § 60.5420b(c)(7) through (10) and (c)(12), as applicable.

(j) ***Process unit equipment affected facility.*** For each process unit equipment affected facility, you must demonstrate continuous compliance with the requirements of § 60.5400b according to paragraphs (j)(1) through (4) and(11) through (15) of this section, unless you meet and comply with the exception in § 60.5402b(b), (e), or (f) or meet the exemption in § 60.5402b(c). Alternatively, if you comply with the GHG and VOC standards for process unit affected facilities using the standards in § 60.5401b, you must comply with paragraphs (j)(5) through (15) of this section, unless you meet the exemption in § 60.5402b(b) or (c) or the exception in § 60.5402b(e) and (f).

(1) You must conduct monitoring for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor and light liquid service and connector in gas/vapor and light liquid service as required by § 60.5400b(b).

(2) You must conduct monitoring as required by § 60.5400b(c) for each pump in light liquid service.

(3) You must conduct monitoring as required by § 60.5400b(d) for each pressure relief device in gas/vapor service.

(4) You must comply with the equipment requirements for each open-ended valve or line as required by § 60.5400b(e).

(5) You must conduct monitoring for each pump in light liquid service as required by § 60.5401b(b).

(6) You must conduct monitoring for each pressure relief device in gas/vapor service as required by § 60.5401b(c).

(7) You must comply with the equipment requirements for each open-ended valve or line as required by § 60.5401b(d).

(8) You must conduct monitoring for each valve in gas/vapor or light liquid service as required by § 60.5401b(f).

(9) You must conduct monitoring for each pump, valve, and connector in heavy liquid service and each pressure relief device in light liquid or heavy liquid service as required by § 60.5401b(g).

(10) You must conduct monitoring for each connector in gas/vapor or light liquid service as required by § 60.5401b(h).

(11) You must collect emissions and meet the closed vent system requirements as required by § 60.5416b for each pump equipped with a dual mechanical seal system that degasses the barrier fluid reservoir to a process or a control device, each pump which captures and transports leakage from the seal or seals to a process or control device, or each pressure relief device which captures and transports leakage through the pressure relief device to a process or control device.

(12) You comply with the requirements specified in paragraph (f) of this section.

(13) You must tag and repair each identified leak as required in § 60.5400(h) or § 60.5401b(i), as applicable.

(14) You must submit semiannual reports as required by § 60.5422b and the annual reports in § 60.5420b(b)(11)(i) through (iv), as applicable.

(15) You must maintain the records specified by § 60.5420b(c)(8), (c)(10), and (c)(12) as applicable and § 60.5421b.

(k) ***Sweetening unit affected facility.*** For each sweetening unit affected facility, you must demonstrate continuous compliance with the requirements of § 60.5405b(b) according to paragraphs (k)(1) through (10) of this section.

(1) You must determine the minimum required continuous reduction efficiency of SO_2 emissions (Z_c) as required by § 60.5406b(b).

(2) You must determine the emission reduction efficiency (R) achieved by your sulfur reduction technology using the procedures in § 60.5406b(c)(1) through (c)(4).

(3) You must demonstrate compliance with the standard at § 60.5405b(b) by comparing the minimum required sulfur dioxide emission reduction efficiency (Z_c) to the emission reduction efficiency achieved by the sulfur recovery technology (R), where R must be greater than or equal to Z_c.

(4) You must calibrate, maintain, and operate monitoring devices or perform measurements to determine the accumulation of sulfur product, the H_2S concentration, the average acid gas flow rate, and the sulfur feed rate in accordance with § 60.5407b(a).

(5) You must determine the required SO_2 emissions reduction efficiency each 24-hour period in accordance with § 60.5407b(a), § 60.5407b(d), and § 60.5407b(e), as applicable.

(6) You must calibrate, maintain, and operate monitoring devices and continuous emission monitors in accordance with § 60.5407b(b), (f), and (g), if you use an oxidation control system or a reduction control system followed by an incineration device.

(7) You must continuously operate the incineration device, if you use an oxidation control system or a reduction control system followed by an incineration device.

(8) You must calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds in accordance with § 60.5407b(c), (f), and (g), if you use a reduction control system not followed by an incineration device.

(9) You must submit the reports as required by § 60.5423b(b) and (d).

(10) You must maintain the records as required by § 60.5423b(a), (e), and (f), as applicable.

(l) ***Continuous compliance.*** For each fugitive emissions components affected facility, you must demonstrate continuous compliance with the requirements of § 60.5397b(a) according to paragraphs (l)(1) through (4) of this section.

(1) You must conduct periodic monitoring surveys as required in § 60.5397b(e) and (g).

(2) You must repair each identified source of fugitive emissions as required in § 60.5397b(h).

(3) You must submit annual reports for fugitive emissions components affected facilities as required in § 60.5420b(b)(1) and (9).

(4) You must maintain records as specified in § 60.5420b(c)(16).

§ 60.5416b What are the initial and continuous cover and closed vent system inspection and monitoring requirements?

For each closed vent system and cover at your well, centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, and process unit equipment affected facilities, you must comply with the applicable requirements of paragraphs (a) and (b) of this section. Each self-contained natural gas process controller must comply with paragraph (b) of this section.

(a) ***Inspections for closed vent systems, covers, and bypass devices.*** If you install a control device or route emissions to a process, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section, except as provided in paragraphs (b)(6) and (7) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (*e.g.,* a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) through (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no identifiable emissions within the first 30 calendar days after startup of the affected facility routing emissions through the closed vent system.

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no identifiable emissions following any time the component is repaired or replaced or the connection is unsealed.

(iii) Conduct AVO inspections in accordance with and at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site as specified in § 60.5397b(g). Process unit equipment affected facilities must conduct annual AVO inspections concurrent with the inspections required by paragraph (a)(1)(ii) of this section.

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iv) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section within the first 30 calendars days after startup of the affected facility routing emissions through the closed vent system to demonstrate that the closed vent system operates with no identifiable emissions.

(ii) Conduct inspections according to the test methods, procedures, and frequencies specified in paragraph (b) of this section to demonstrate that the components or connections operate with no identifiable emissions.

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no identifiable emissions following any time the component is repaired or replaced or the connection is unsealed.

(iv) Conduct AVO inspections in accordance with and at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site, as specified in § 60.5397b(g). Process unit equipment affected facilities must conduct annual AVO inspections concurrent with the inspections required by paragraph (a)(2)(iii) of this section.

(3) For each cover, you must meet the requirements of paragraphs (a)(3)(i) through (iv) of this section.

(i) Conduct the inspections specified in paragraphs (a)(3)(ii) through (iv) of this section to identify defects that could result in air emissions and to ensure the cover operates with no identifiable emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) An initial inspection according to the test methods and procedures specified in paragraph (b) of this section, following installation of the cover to demonstrate that each cover operates with no identifiable emissions.

(iii) Conduct AVO inspections in accordance with and at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site as specified in § 60.5397b(g). Process unit equipment affected facilities must conduct annual AVO inspections concurrent with the inspections required by paragraph (a)(1)(ii) of this section.

(iv) Inspections according to the test methods, procedures, and schedules specified in paragraph (b) of this section to demonstrate that each cover operates with no identifiable emissions.

(4) For each bypass device, except as provided for in § 60.5411b(a)(4)(ii), you must meet the requirements of paragraph (a)(4)(i) or (ii) of this section.

(i) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the stream away from the control device and to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device.

(b) ***No identifiable emissions test methods and procedures.*** If you are required to conduct an inspection of a closed vent system and cover as specified in paragraph (a)(1), (2), or (3) of this section or § 60.5398b(b), you must meet the requirements of paragraphs (b)(1) through (9) of this section. You must meet the requirements of paragraphs (b)(1), (2), (4), and (9) of this section for each self-contained process controller at your process controller affected facility as specified at § 60.5390b(a)(2).

(1) ***Initial and periodic inspection.*** You must conduct initial and periodic no identifiable emissions inspections as specified in paragraphs (b)(1)(i) through (iii) of this section, as applicable.

(i) You must conduct inspections for no identifiable emissions from your covers and closed vent systems at your well, centrifugal compressor, reciprocating compressor, process controller, pump, or storage vessel affected facility, using the procedures for conducting OGI inspections in § 60.5397b(c)(7). As an alternative you may conduct inspections in accordance with Method 21 of appendix A-7 to this part. Monitoring must be conducted at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site, as specified in § 60.5397b(g).

(ii) For covers and closed vent systems located at onshore natural gas processing plants, OGI inspections for no identifiable emissions must be conducted initially and bimonthly in accordance with appendix K to this part. As an alternative you must conduct quarterly inspections for no identifiable emissions in accordance with Method 21 of appendix A-7 to this part.

(iii) For your self-contained process controller, you must conduct initial and quarterly inspections for no identifiable emissions using the procedures for conducting OGI inspections in § 60.5397b(c)(7). As an alternative you may conduct quarterly inspections in accordance with Method 21 of appendix A-7 to this part.

(2) ***OGI application,*** Where OGI is used, the closed vent system, cover, or self-contained process controller is determined to operate with no identifiable emissions if no emissions are imaged during the inspection. Emissions imaged by OGI constitute a deviation of the no identifiable emissions standard until an OGI inspection conducted in accordance with this paragraph (b)(2) of this section determines that the closed vent system, cover, or self-contained process controller, as applicable, operates with no identifiable emissions.

(3) ***AVO application.*** Where AVO inspections are required, the closed vent system or cover is determined to operate with no identifiable emissions if no emissions are detected by AVO. Emissions detected by AVO constitute a deviation of the no identifiable emissions standard until an AVO inspection determines that the closed vent system or cover operates with no identifiable emissions.

(4) ***Method 21 application.*** Where Method 21 of appendix A-7 to this part is used for the inspection, the requirements of paragraphs (b)(4)(i) through (vii) of this section apply.

(i) The detection instrument must meet the performance criteria of Method 21 of appendix A-7 to this part, except that the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(ii) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 of appendix A-7 to this part.

(iii) Calibration gases must be as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(B) A mixture of methane in air at a concentration less than 500 ppmv.

(iv) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 of appendix A-7 to this part.

(v) Your detection instrument must meet the performance criteria specified in paragraphs (b)(4)(v)(A) and (B) of this section.

(A) Except as provided in paragraph (b)(4)(v)(B) of this section, the detection instrument must meet the performance criteria of Method 21 of appendix A-7 to this part, except the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream.

For process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(B) If no instrument is available that will meet the performance criteria specified in paragraph (b)(4)(v)(A) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(4)(v)(A) of this section.

(vi) You must determine if a potential leak interface operates with no identifiable emissions using the applicable procedure specified in paragraph (b)(4)(vi)(A) or (B) of this section.

(A) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(4)(vii) of this section.

(B) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(4)(iv) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(4)(vii) of this section.

(vii) A closed vent system, cover, or self-contained process controller is determined to operate with no identifiable emissions if the organic concentration value determined in paragraph (b)(4)(vi) of this section is less than 500 ppmv. An organic concentration value determined in paragraph (b)(4)(vi) of this section of greater than or equal to 500 ppmv constitutes a deviation of the no identifiable emissions standard until an inspection conducted in accordance with paragraph (b)(4) of this section determines that the closed vent system, cover, or self-contained process controller, as applicable, operates with no identifiable emissions.

(5) ***Repairs.*** Whenever emissions or a defect is detected, you must repair the emissions or defect as soon as practicable according to the requirements of paragraphs (b)(5)(i) through (iii) of this section, except as provided in paragraph (b)(6) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the emissions or defect is detected.

(ii) Repair must be completed no later than 30 calendar days after the emissions or defect is detected.

(iii) For covers, grease or another substance compatible with the gasket material must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(6) ***Delay of repair.*** Delay of repair of a closed vent system or cover for which emissions or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(7) ***Unsafe to inspect requirements.*** You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements of paragraphs (b)(7)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1), (2), or (3) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(8) ***Difficult to inspect requirements.*** You may designate any parts of the closed vent system or cover as difficult to inspect if the requirements of paragraphs (b)(8)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(9) ***Records and reports.*** You must maintain records of all inspection results as specified in § 60.5420b(c)(8) through (10). You must submit the reports as specified in § 60.5420b(b)(11).

§ 60.5417b What are the continuous monitoring requirements for my control devices?

You must meet the requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your well, centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, and process unit equipment affected facilities.

(a) For each control device used to comply with the emission reduction standard in § 60.5377b(b) for well affected facilities, § 60.5380b(a)(1) for centrifugal compressor affected facilities, § 60.5385b(d)(2) for reciprocating compressor affected facilities, § 60.5390b(b)(3) for your process controller affected facility in Alaska, § 60.5393b(b)(1) for your pumps affected facility, § 60.5395b(a)(2) for your storage vessel affected facility, or either § 60.5400b(f) or § 60.5401b(e) for your process equipment affected facility, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (h) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with § 60.5412b(a)(3), you are exempt from the requirements of paragraph (f) of this section. If you operate an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), you must operate the control device as specified in paragraph (i) of this section instead of using the procedures specified in paragraphs (c) through (h) of this section. You must keep records and report in accordance with paragraph (j) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) You must meet the specifications and requirements of paragraphs (c)(1) through (4) of this section.

(1) Except for continuous parameter monitoring systems used to detect the presence of a pilot or combustion flame, each continuous parameter monitoring system must measure data values at least once every hour and record the values for each parameter as required in paragraphs (c)(1)(i) or (ii) of this section. Continuous parameter monitoring systems used to detect the presence of a pilot or combustion flame must record a reading at least once every 5 minutes.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period.

(2) You must prepare a monitoring plan that covers each control device for affected facilities within each company-defined area. The monitoring plan must address the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition of a pilot or combustion flame are exempt from the calibration, quality assurance and quality control requirements of this section.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 60.13(b).

(v) Ongoing recordkeeping procedures in accordance with provisions in § 60.7(f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition of a pilot or combustion flame are exempt from the calibration, quality assurance and quality control requirements of this section.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in paragraphs (d)(1) through (8) of this section, as applicable. Instead of complying with the requirements in paragraphs (d)(1) through (8) of this section, you may install an organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device to demonstrate compliance with the applicable performance requirement specified in § 60.5412b(a)(1). The monitor must meet the requirements of Performance Specification 8 or 9 of appendix B to this part. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications and the requirements in Performance Specification 8 or 9. You may also request approval from the Administrator to monitor different operating parameters than those specified in paragraphs (d)(1) through (8) of this section in accordance with § 60.13(i).

(1) For an enclosed combustion device that demonstrates during the performance test conducted under § 60.5413b(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in degrees Celsius, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature. You must also comply with the requirements of paragraphs (d)(8)(i), (iv), and (v) of this section.

(2) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in degrees Celsius, or ±2.5 °C, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(3) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in degrees Celsius, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(4) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in degrees Celsius, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(5) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(5)(i) and (ii) of this section. You also must monitor the design carbon service life established using a design analysis performed as specified in § 60.5413b(c)(2).

(i) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(ii) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in degrees Celsius, or ±2.5 °C, whichever value is greater.

(6) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in § 60.5413b(c)(3). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(7) For a combustion control device whose model is tested under § 60.5413b(d), continuous monitoring systems as specified in paragraphs (d)(8)(i) through (iv) and (d)(8)(vi) of this section and visible emission observations conducted as specified in paragraph (d)(8)(v) of this section.

(8) For an enclosed combustion device other than those listed in paragraphs (d)(1) through (3) and (7) of this section or for a flare, continuous monitoring systems as specified in paragraphs (d)(8)(i) through (iv) of this section and visible emission observations conducted as specified in paragraph (d)(8)(v) of this section. Additionally, for enclosed combustion devices or flares that are air-assisted or steam-assisted, the continuous monitoring systems specified in paragraph (d)(8)(vi) of this section.

(i) Continuously monitor at least once every five minutes for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot or combustion flame is present at all times. An alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit. Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this section.

(ii) Except as provided in this paragraph (d)(8)(ii) and paragraph (d)(8)(iii) of this section, use one of the following methods to continuously determine the NHV of the inlet gas to the enclosed combustion device or flare at standard conditions. If the only inlet gas stream to the enclosed combustion device or flare is associated gas from a well affected facility, the NHV of the inlet stream is considered to be sufficiently above the minimum required NHV for the inlet gas, and you are not required to conduct the continuous monitoring in this paragraph (d)(8)(ii) of this section or the demonstration in paragraph (d)(8)(iii) of this section.

(A) A calorimeter with a minimum accuracy of ±2 percent of span.

(B) A gas chromatograph that meets the requirements in paragraphs (d)(8)(ii)(B)(*1*) through (*5*) of this section.

(*1*) You must follow the procedure in Performance Specification 9 of appendix B of this part, 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). Calibration gas cylinders must be certified to an accuracy of 2 percent and traceable to National Institute of Standards and Technology (NIST) standards.

(*2*) You must meet the accuracy requirements in Performance Specification 9 of appendix B of this part.

(*3*) You must use a calibration gas or multiple gases that includes the compounds that are reasonably expected to be present in the flare gas stream. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. You may only use the compounds used to calibrate the gas chromatograph in the calculation of the vent gas NHV.

(*4*) In lieu of the calibration gas described in paragraph (d)(8)(ii)(*B*)(*3*) of this section, you may use a surrogate calibration gas consisting of hydrogen and C1 through C5 normal hydrocarbons. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. Use the response factor for the nearest normal hydrocarbon (*i.e.,* n-alkane) in the calibration mixture to quantify unknown components detected in the analysis. Use the response factor for n-pentane to quantify unknown components detected in the analysis that elute after n-pentane.

(*5*) To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use the net heating value at 25 °C and 1 atmosphere.

(C) A mass spectrometer that meets the requirements in paragraphs (d)(8)(ii)(C)(*1*) through (*6*) of this section.

(*1*) You must meet applicable requirements in Performance Specification 9 of appendix B of this part 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. 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). Calibration gas cylinders must be certified to an accuracy of 2 percent and traceable to NIST standards.

(*2*) 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 the following equation:

Equation 1 to paragraph (d)(8)(ii)(C)(*2*)

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

Where:
Cm = Average instrument response (ppm).
Ca = Certified cylinder gas value (ppm).

(*3*) You must use a calibration gas or multiple gases that includes the compounds that are reasonably expected to be present in the flare gas stream. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. You may only use the compounds used to calibrate the mass spectrometer in the calculation of the vent gas NHV.

(*4*) In lieu of the calibration gas described in paragraph (d)(8)(ii)(C)(*3*) of this section, you may use a surrogate calibration gas consisting of hydrogen and C1 through C5 normal hydrocarbons. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. 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. 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*) To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use the net heating value at 25 °C and 1 atmosphere.

(D) A grab sampling system capable of collecting an evacuated canister sample for subsequent compositional analysis at least once every eight hours. Subsequent compositional analysis of the samples must be performed according to ASTM D1945-14 (R2019) (incorporated by reference, see § 60.17). To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use the net heating value at 25 °C and 1 atmosphere.

(iii) For an unassisted or pressure-assisted flare or enclosed combustion device, if you demonstrate according to the methods described in paragraphs (d)(8)(iii)(A) through (F) of this section that the NHV of the inlet gas to the enclosed combustion device or flare consistently exceeds the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B) or (C), continuous monitoring of the NHV is not required, but you must conduct the ongoing sampling in paragraph (d)(8)(iii)(G) of this section. For flares and enclosed combustion devices that use only perimeter assist air and do not use steam assist or premix assist air, if you demonstrate according to the methods described in paragraphs (d)(8)(iii)(A) through (F) of this section that the NHV of the inlet gas to the enclosed combustion device or flare consistently exceeds 300 Btu/scf, continuous monitoring of the NHV is not required, but you must conduct the ongoing sampling in paragraph (d)(8)(iii)(G) of this section. For an unassisted or pressure-assisted flare or enclosed combustion device, in lieu of conducting the demonstration outlined in paragraphs (d)(8)(iii)(A) through (D) of this section, you may conduct the demonstration outlined in paragraph (d)(8)(iii)(H) of this section, but you must still comply with paragraphs (d)(8)(iii)(E) through (G) of this section.

(A) Continuously monitor or collect a sample of the inlet gas to the enclosed combustion device or flare twice daily to determine the average NHV of the gas stream for 14 consecutive operating days. If you do not continuously monitor the NHV, the minimum time of collection for each individual sample be at least one hour. Consecutive samples must be separated by at least 6 hours. If inlet gas flow is intermittent such that there are not at least 28 samples over the 14 operating day period, you must continue to collect samples of the inlet gas beyond the 14 operating day period until you collect a minimum of 28 samples.

(B) If you collect samples twice per day, count the number of samples where the NHV value is less than 1.2 times the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B), (C), or paragraph (d)(8)(iii) of this section (*i.e.,* values that are less than 240, 360, or 960 Btu/scf, as applicable) during the sample collection period in paragraph (d)(8)(iii)(A) of this section.

(C) If you continuously sample the inlet stream for 14 days, count the number of hourly average NHV values that are less than the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B), § 60.5415b(f)(1)(vii)(C)(*1*), or paragraph (d)(8)(iii) of this section (*i.e.,* values that are less than 200, 300, or 800 Btu/scf, as applicable), during the sample collection period in paragraph (d)(8)(iii)(A) of this section.

(D) If there are no samples counted under paragraph (d)(8)(iii)(B) of this section or there are no hourly values counted under paragraph (d)(8)(iii)(C) of this section, the gas stream is considered to consistently exceed the applicable NHV operating limit and on-going continuous monitoring is not required.

(E) If process operations are revised that could impact the NHV of the gas sent to the enclosed combustion device or flare, such as the removal or addition of process equipment, and at any time the Administrator requires, re-evaluation of the gas stream must be performed according to paragraphs (d)(8)(iii)(A) through (D) of this section to ensure the gas stream still consistently exceeds the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B), (f)(1)(vii)(C)(*1*), or paragraph (d)(8)(iii) of this section.

(F) When collecting samples under paragraph (d)(8)(iii)(A) of this section, the owner or operator must account for any sources of inert gases that can be sent to the enclosed combustion device or flare (*e.g.,* streams from compressors in acid gas service, streams from enhanced oil recovery facilities). The report in § 60.5420b(b)(11)(v)(I) and the records of the demonstration in § 60.5420b(c)(11)(vi) must note whether the enclosed combustion device or flare has the potential to receive inert gases, and if so, whether the sampling included periods where the highest percentage of inert gases were sent to the enclosed combustion device or flare. If the introduction of inerts is intermittent and does not occur during the initial demonstration, the introduction of inerts will be considered a revision to process operations that triggers a re-evaluation under paragraph (d)(8)(iii)(E) of this section. If conditions at the site did not allow sampling during periods where the introduction of inert gases was at the highest percentage possible, increasing the percentage of inerts will be considered a revision to process operations that triggers a re-evaluation under paragraph (d)(8)(iii)(E) of this section.

(G) You must collect three samples of the inlet gas to the enclosed combustion device or flare at least once every 5 years. The minimum time of collection for each individual sample must be at least one hour. The samples must be taken during the period with the lowest expected NHV (*i.e.,* the period with the highest percentage of inerts). The first set of periodic samples must be taken, or continuous monitoring commenced, no later than 60 calendar months following the last sample taken under paragraph (d)(8)(iii)(A) of this section. Subsequent periodic samples must be taken, or continuous monitoring commenced, no later than 60 calendar months following the previous sample. If any sample has an NHV value less than 1.2 times the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B), § 60.5415b(f)(1)(vii)(C), or paragraph (d)(8)(iii) of this section (*i.e.,* values that are less than 240, 360, or 960 Btu/scf, as applicable), you must conduct the monitoring required by paragraph (d)(8)(ii) of this section.

(H) You may request an alternative test method under § 60.5412b(d) to demonstrate that the flare or enclosed combustion device reduces methane and VOC in the gases vented to the device by 95.0 percent by weight or greater. You must use an alternative test method that demonstrates compliance with the combustion efficiency limit; you may not use an alternative test method that demonstrates compliance with NHV_{cz} and NHV_{dil} in lieu of measuring combustion efficiency directly. You must measure data values at the frequency specified in the alternative test method and conduct the quality assurance and quality control requirements outlined in the alternative test method at the frequency outlined in the alternative test method. You must monitor the combustion efficiency of the flare continuously for 14 days. If there are no values of the combustion efficiency measured by the alternative test method that are less than 95.0 percent, the gas stream is considered to consistently exceed the applicable NHV operating limit, and you are not required to continuously monitor the NHV of the inlet gas to the flare or enclosed combustion device.

(iv) Except as noted in paragraphs (d)(8)(iv)(A) through (E) of this section, a continuous parameter monitoring system for measuring the flow of gas to the enclosed combustion device or flare. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as inlet line pressure, line size, and burner nozzle dimensions, to satisfy this requirement. The monitoring instrument must have an accuracy of ±10 percent or better at the maximum expected flow rate.

(A) Pressure-assisted flares and pressure-assisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(B) Unassisted flares are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you meet the conditions in paragraphs (d)(8)(iv)(B)(*1*) and (*2*) of this section.

(*1*) You must demonstrate, based on the maximum potential pressure of units manifolded to the flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the flare cannot cause the flare tip velocity to exceed 18.3 meter/second (60 feet/second). If there are changes to the process or control device that can be reasonably expected to impact the maximum flow rate to the flare, you must conduct a new demonstration to determine whether the maximum flow rate to the flare is less than 18.3 meter/second (60 feet/second).

(*2*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(C) Unassisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you meet the conditions in paragraphs (d)(8)(iv)(C)(*1*) and (*2*) of this section.

(*1*) You must demonstrate, based on the maximum potential pressure of units manifolded to the enclosed combustion device and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the enclosed combustion device cannot cause the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section to be exceeded. If there are changes to the process or control device that can be reasonably expected to impact the maximum flow rate to the enclosed combustion device, you must conduct a new demonstration to determine whether the maximum flow rate to the enclosed combustor is less than the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section.

(*2*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(D) Air-assisted flares or enclosed combustion devices that use only perimeter assist air and have no assist steam or premix assist air are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device or the flow of assist air if you meet the conditions in paragraphs (d)(8)(iv)(D)(*1*) and (*2*) of this section. For these flares and enclosed combustion devices, NHV_{cz} is assumed to be equal to the vent gas NHV.

(*1*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(*2*) You must demonstrate, based on the maximum flow rate of perimeter assist air to the enclosed combustion device or flare and applicable engineering calculations, that the NHV_{dil} can never be less than the minimum required $NHV_{dil.}$ The demonstration must clearly document why the maximum flow rate of perimeter assist air will never exceed the rate used in the demonstration. You must use the minimum flow rate of vent gas allowed by your backpressure regulator valve and the minimum expected value of the NHV of the inlet gas to the enclosed combustion device or flare based on previous sampling results or process knowledge of the streams sent to the enclosed combustion device or flare in your demonstration. You must update this demonstration if there are changes to the backpressure regulator valve, the backpressure regulator valve set point, or the maximum flow rate of perimeter assist air. You must also update this demonstration if any sampling results of the NHV of the inlet gas to the enclosed combustion device or flare under paragraphs (d)(8)(ii) or (iii) of this section are lower than the NHV vent gas value used in your demonstration.

(E) Air-assisted flares or enclosed combustion devices that use only premix assist air and have no assist steam or perimeter assist air are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device or the flow of assist air if you meet the conditions in paragraphs (d)(8)(iv)(E)(*1*) and (*2*) of this section.

(*1*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(*2*) You must demonstrate, based on the maximum flow rate of premix assist air to the enclosed combustion device or flare and applicable engineering calculations, that the NHV_{cz} will never be less than the minimum required $NHV_{cz.}$ The demonstration must clearly document why the maximum flow rate of premix assist air will never exceed the rate used in the demonstration. You must use the minimum flow rate of vent gas allowed by your backpressure regulator valve in and the minimum expected value of the NHV of the inlet gas to the enclosed combustion device or flare based on previous sampling results or process knowledge of the streams sent to the enclosed combustion device or flare in your demonstration. You must update this demonstration if there are changes to the backpressure regulator valve, the backpressure regulator valve set point, or the maximum flow rate of premix assist air. You must also update this demonstration if any sampling results of the NHV of the inlet gas to the enclosed combustion device or flare under paragraphs (d)(8)(ii) or (iii) of this section are lower than the NHV vent gas value used in your demonstration.

(v) Conduct inspections monthly and at other times as requested by the Administrator to monitor for visible emissions from the combustion device using section 11 of Method 22 of appendix A of this part or conduct visible emissions monitoring according to paragraph (h) of this section. The observation period shall be 15 minutes or once the amount of time visible emissions is present has exceeded 1 minute. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period.

(vi) If you use a flare or enclosed combustion device that is air-assisted or steam-assisted, you must also meet the following requirements.

(A) Except as allowed by paragraph (d)(8)(iv)(E) of this section, you must monitor and calculate NHV_{cz} as specified in § 63.670(m) of this chapter. Additionally, for flares and enclosed combustion devices that use only perimeter assist air and do not use steam assist or premix assist air, the NHV_{cz} is equal to the vent gas NHV. When NHV_{cz} is equal to the vent gas NHV, you are not required to continuously monitor NHV_{cz} if you meet the requirements in paragraph (d)(8)(iii) of this section.

(B) Except as allowed by paragraph (d)(8)(iv)(D) of this section, for each flare using perimeter assist air, you must also monitor and calculate NHV_{dil} as specified in § 63.670(n) of this chapter. If the only assist air provided to the flare or enclosed combustion control device is perimeter assist air intentionally entrained in lower and/or upper steam at the flare tip and the effective diameter is 9 inches or greater, you are only required to comply with the NHV_{cz} limit specified in paragraph (f)(8)(vi)(A) of this section.

(C) Except as allowed by paragraph (d)(8)(iv) of this section, you must monitor the flare vent gas and assist gas as specified in § 63.670(i) of this chapter.

(D) You must determine the flare vent gas net heating value as specified in § 63.670(l) of this chapter using one of the methods specified in paragraph (d)(8)(ii) of this section. Where the phrase “petroleum refinery” is used, for purposes of this subpart, it will refer to flares controlling an affected facility under this subpart. If you are not required to continuously monitor the NHV of the inlet gas because you have demonstrated that it consistently exceeds the applicable operating limit as provided in paragraph (d)(8)(iii) of this section, you must use the lowest net heating value measured in the sampling program in paragraph (d)(8)(iii) of this section for the calculations performed in paragraphs (d)(8)(vi)(A) and (B). You must update this value if a subsequent sampling result of the NHV of the inlet gas to the enclosed combustion device or flare under paragraph (d)(8)(iii) of this section is lower than the NHV vent gas value used in your calculations.

(e) Calculate the value of the applicable monitored parameter in accordance with paragraphs (e)(1) through (5) of this section.

(1) You must calculate the daily average value for condenser outlet temperature for each operating day, using the data recorded by the monitoring system. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(2) You must use the 5-minute readings from the heat sensing devices to assess the presence of a pilot or combustion flame.

(3) You must use the regeneration cycle time (*i.e.,* duration of the carbon bed steaming cycle) for each regenerative-type carbon adsorption system to calculate the average parameter to compare with the maximum steam mass flow or volumetric flow during each carbon bed regeneration cycle and the maximum carbon bed temperature during the steaming cycle. The carbon bed temperature after the regeneration cycle should not be averaged; you must use the carbon bed temperature measured within 15 minutes of completing the cooling cycle to compare with the minimum carbon bed temperature after the regeneration cycle.

(4) You must use 15-minute blocks to calculate NHV_{cz} and NHV_{dil}.

(5) For all operating parameters others than those described in paragraphs (e)(1) through (4) of this section, you must calculate the 3-hour rolling average of each monitored parameter. For each operating hour, calculate the hourly value of the operating parameter from your continuous monitoring system. Average the three most recent hours of data to determine the 3-hour average. Determine the 3-hour rolling average by recalculating the 3-hour average each hour.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 60.5412b(a)(1) or (2). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iv) of this section.

(i) If you conduct performance tests in accordance with the requirements of § 60.5413b(b) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412b(a)(1) or (2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser or carbon adsorption system design analysis or control device manufacturer recommendations or a combination of both. If you operate an enclosed combustion device, you must establish the maximum inlet flow rate based on values measured during the performance test and you may establish the minimum inlet flow rate based on control device manufacturer recommendations.

(ii) If you use a condenser or carbon adsorption system design analysis in accordance with the requirements of § 60.5413b(c) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412b(a)(2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the design analysis and supplemented, as necessary, by the manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under § 60.5413b(d) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412b(a)(1), then your control device inlet gas flow rate must be equal to or greater than the minimum inlet gas flow rate and equal to or less than the maximum inlet gas flow rate determined by the manufacturer.

(iv) If you operate an enclosed combustion device where the combustion zone temperature is not an indicator of destruction efficiency or a control device where the performance test requirement was met under § 60.5413b(d), you must maintain the NHV of the gas sent to the enclosed combustion device, the NHV_{cz}, and the NHV_{dil} above the applicable limits specified in paragraphs § 60.5412b(a)(1)(iv)(A) through (D).

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of § 60.5413b(b) to demonstrate that the condenser achieves the applicable performance requirements of § 60.5412b(a)(2), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of § 60.5413b(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in § 60.5412b(a)(2), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (7) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (7) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is less than the minimum operating parameter limit (and, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section; for flares, when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is above the limits specified in § 60.5415b(f)(1)(vii)(B); or when the heat sensing device indicates that there is no pilot or combustion flame present for any time period. If you use a backpressure regulator valve to maintain the inlet gas flow to an enclosed combustion device or flare above the minimum value, a deviation occurs if the annual inspection finds that the backpressure regulator valve set point is not set correctly or indicates that the backpressure regulator valve does not fully close when not in the open position.

(2) If you are subject to § 60.5412b(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 60.5415b(f)(1)(ix)(D) is less than 95.0 percent.

(3) If you are subject to § 60.5412b(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in § 60.5415b(f)(1)(ix)(D)(*1*) or (*2*) is less than 95.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraph (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to § 60.5411b(a)(4)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to § 60.5411b(a)(4)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under § 60.5413b(d), a deviation occurs when the conditions of paragraph (g)(4), (5), or (6)(i) through (vi) of this section are met.

(i) The hourly inlet gas flow rate is less than the minimum inlet gas flow rate or greater than the maximum inlet gas flow rate determined by the manufacturer. If you use a backpressure regulator valve to maintain the inlet gas flow above the minimum value, a deviation occurs if the annual inspection finds that the backpressure regulator valve set point is not set correctly or indicates that the backpressure regulator valve does not fully close when not in the open position.

(ii) Results of the monthly visible emissions test conducted under § 60.5413b(e)(3) or monitoring under paragraph (h) of this section indicate visible emissions exceed 1 minute in any 15-minute period.

(iii) There is no indication of the presence of a pilot or combustion flame for any 5-minute time period.

(iv) The control device is not maintained in a leak free condition.

(v) The control device is not operated in accordance with the manufacturer's written operating instructions, procedures and maintenance schedule.

(vi) The NHV of the vent gas, the NHV_{cz}, or the NHV_{dil} is below the applicable limit specified in § 60.5412b(a)(1)(iv).

(7) For an enclosed combustion device or flare subject to paragraph (d)(8) of this section, a deviation occurs when any of the conditions described by paragraphs (g)(1), (4) or (5) of this section are met or when the results of the visible emissions monitoring conducted under paragraph (d)(8)(v) or (h) of this section exceed 1 minute in any 15-minute period.

(h) For enclosed combustion devices and flares, in lieu of conducting a visible emissions observation using Method 22 of appendix A-7 to this part, you may use a video surveillance camera to continuously monitor and record the flare flame according to the requirements in paragraphs (h)(1) through (6) of this section.

(1) You must provide real-time high-definition video surveillance camera output (*i.e.,* at least 720p) at a frame rate of at least 15 frames per second to the control room or other continuously manned location where the camera images may be viewed at the same resolution at any time.

(2) You must record at least one frame every 15 seconds with date and time stamp.

(3) The camera must be located at a reasonable distance above the flare flame at an angle suitable for visual emissions observations. The position of the camera should be such that the sun is not in the field of view.

(4) The camera must be located no more than 400 m (0.25 miles) from the emission source.

(5) Operators must look at the video feed at least once daily for an observation period of at least 1 minute to determine if visible emissions are present. If visible emissions are present during a daily observation, the operator must observe the video feed for 15 minutes or until the amount of time visible emissions is present has exceeded 1 minute, whichever time period is less.

(6) Enclosed combustion devices and flares must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period.

(i) If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), you must comply with paragraphs (i)(1) through (6) of this section.

(1) You must measure data values at the frequency specified in the alternative test method.

(2) You must prepare a monitoring plan that covers each control device for affected facilities within each company-defined area. The monitoring plan must address the monitoring system design, data collection, and the quality assurance and quality control elements outlined in the alternative test method and in paragraphs (i)(2)(i) through (iii) of this section. You must operate and maintain each monitoring system in accordance with the procedures in your monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment.

(ii) Location of monitoring system in relation to the monitored control device.

(iii) Ongoing reporting and recordkeeping procedures.

(3) You must conduct the quality assurance and quality control requirements outlined in the alternative test method at the frequency outlined in the alternative test method.

(4) If required by § 5412b(d)(4), you must conduct the inspections required by paragraph (d)(8)(v) of this section.

(5) If required by § 5412b(d)(5), you must install the pilot or combustion flame monitoring system required by paragraph (d)(8)(i) of this section.

(6) A deviation for the control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (i)(6)(i) through (v) of this section being met.

(i) A deviation occurs if the combustion efficiency is less than 95.0 percent, the combustion zone NHV is less than 270 Btu/scf, or the NHV dilution parameter is less than 22 Btu/sqft.

(ii) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(iii) A deviation occurs when any of the conditions described by paragraph (g)(5) of this section are met.

(iv) If required by paragraph (i)(4) of this section to conduct visible emissions inspections, a deviation occurs when the results of the visible emissions monitoring conducted under paragraph (d)(8)(v) or (h) of this section exceeds 1 minute in any 15-minute period.

(v) If required by paragraph (i)(5) of this section to install a pilot or combustion flame monitoring system, a deviation occurs when there is no indication of the presence of a pilot or combustion flame for any 5-minute period.

(j) You must submit annual reports for control devices as required in § 60.5420b(b)(1) and (11). You must maintain records as specified in § 60.5420b(c)(1).

§ 60.5420b What are my notification, reporting, and recordkeeping requirements?

(a) ***Notifications.*** You must submit notifications according to paragraphs (a)(1) and (2) of this section if you own or operate one or more of the affected facilities specified in § 60.5365b that was constructed, modified, or reconstructed during the reporting period. You must submit the notification in paragraph (a)(3) of this section if you use an alternative standard for fugitive emissions components in accordance with § 60.5399b. You must submit the notification in paragraph (a)(4) of this section if you undertake well closure activities as specified in § 60.5397b(l).

(1) If you own or operate a process unit equipment affected facility located at an onshore natural gas processing plant, or a sweetening unit, you must submit the notifications required in §§ 60.7(a)(1), (3), and (4) and 60.15(d). If you own or operate a well, centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, collection of fugitive emissions components at a well site, or collection of fugitive emissions components at a compressor station affected facility, you are not required to submit the notifications required in §§ 60.7(a)(1), (3), and (4) and 60.15(d).

(2) If you own or operate a well affected facility, you must notify the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the United States Well Number; the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format. If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of this paragraph.

(3) An owner or operator electing to comply with the provisions of § 60.5399b for fugitive emissions components shall notify the Administrator of the alternative fugitive emissions standard selected within the annual report, as specified in paragraph (b)(9)(iii) of this section.

(4) An owner or operator who commences well closure activities must submit the following notices to the Administrator according to the schedule in paragraph (a)(4)(i) and (ii) of this section. The notification shall include contact information for the owner or operator; the United States Well Number; the latitude and longitude coordinates for each well at the well site in decimal degrees to an accuracy and precision of five

(5) decimals of a degree using the North American Datum of 1983. You must submit notifications in portable document format (PDF) following the procedures specified in paragraph (d) of this section.

(i) You must submit a well closure plan to the Administrator within 30 days of the cessation of production from all wells located at the well site.

(ii) You must submit a notification of the intent to close a well site 60 days before you begin well closure activities.

(b) ***Reporting requirements.*** You must submit annual reports containing the information specified in paragraphs (b)(1) through (14) of this section following the procedure specified in paragraph (b)(15) of this section. You must submit performance test reports as specified in paragraph (b)(12) or (13) of this section, if applicable. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to § 60.5410b. Subsequent annual reports are due no later than the same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (14) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period. You must submit the information in paragraph (b)(1)(v) of this section, as applicable, for your well affected facility which undergoes a change of ownership during the reporting period, regardless of whether reporting under paragraphs (b)(2) through (4) of this section is required for the well affected facility.

(1) The general information specified in paragraphs (b)(1)(i) through (v) of this section is required for all reports.

(i) The company name, facility site name associated with the affected facility, U.S. Well ID or U.S. Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (b)(1)(iv).

(v) Identification of each well affected facility for which ownership changed due to sale or transfer of ownership including the United States Well Number; the latitude and longitude coordinates of the well affected facility in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the information in paragraph (b)(1)(v)(A) or (B) of this section, as applicable.

(A) The name and contact information, including the phone number, email address, and mailing address, of the owner or operator to which you sold or transferred ownership of the well affected facility identified in paragraph (b)(v) of this section.

(B) The name and contact information, including the phone number, email address, and mailing address, of the owner or operator from whom you acquired the well affected facility identified in paragraph (b)(v) of this section.

(2) For each well affected facility that is subject to § 60.5375b(a) or (f), the records of each well completion operation conducted during the reporting period, including the information specified in paragraphs (b)(2)(i) through (xiv) of this section, if applicable. In lieu of submitting the records specified in paragraphs (b)(2)(i) through (xiv) of this section, the owner or operator may submit a list of each well completion with hydraulic fracturing completed during the reporting period, and the digital photograph required by paragraph (c)(1)(v) of this section for each well completion. For each well affected facility that routes all flowback entirely through one or more production separators, only the records specified in paragraphs (b)(2)(i) through (iv) and (vi) of this section are required to be reported. For periods where salable gas is unable to be separated, the records specified in paragraphs (b)(2)(iv) and (viii) through (xii) of this section must also be reported, as applicable. For each well affected facility that is subject to § 60.5375b(g), the record specified in paragraph (b)(2)(xv) of this section is required to be reported. For each well affected facility which makes a claim that the exemption in § 60.5375b(h) was met, the records specified in paragraph (b)(2)(i) through (iv) and (b)(2)(xvi) of this section are required to be reported.

(i) Well Completion ID.

(ii) Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983.

(iii) U.S. Well ID.

(iv) The date and time of the onset of flowback following hydraulic fracturing or refracturing or identification that the well immediately starts production.

(v) The date and time of each attempt to direct flowback to a separator as required in § 60.5375b(a)(1)(ii).

(vi) The date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production.

(vii) The duration (in hours) of flowback.

(viii) The duration (in hours) of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve).

(ix) The duration (in hours) of combustion.

(x) The duration (in hours) of venting.

(xi) The specific reasons for venting in lieu of capture or combustion.

(xii) For any deviations recorded as specified in paragraph (c)(1)(ii) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation.

(xiii) For each well affected facility subject to § 60.5375b(f), a record of the well type (*i.e.,* wildcat well, delineation well, or low pressure well (as defined § 60.5430b)) and supporting inputs and calculations, if applicable.

(xiv) For each well affected facility for which you claim an exception under § 60.5375b(a)(2), the specific exception claimed and reasons why the well meets the claimed exception.

(xv) For each well affected facility with less than 300 scf of gas per stock tank barrel of oil produced, the supporting analysis that was performed in order the make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field.

(xvi) For each well affected facility which meets the exemption in § 60.5375b(h), a statement that the well completion operation requirements of § 60.5375b(a)(1) through (3) were met.

(3) For each well affected facility that is subject to § 60.5376b(a)(1) or (2), your annual report is required to include the information specified in paragraphs (b)(3)(i) and (ii) of this section, as applicable.

(i) For each well affected facility where all gas well liquids unloading operations comply with § 60.5376b(a)(1), your annual report must include the information specified in paragraphs (b)(3)(i)(A) through (C) of this section, as applicable.

(A) Identification of each well affected facility (U.S. Well ID or U.S. Well ID associated with the well affected facility) that conducts a gas well liquid unloading operation during the reporting period using a method that does not vent to the atmosphere and the technology or technique used. If more than one non-venting technology or technique is used, you must identify all of the differing non-venting liquids unloading methods used during the reporting period.

(B) Number of gas well liquids unloading operations conducted during the year where the well affected facility identified in (b)(3)(i)(A) had unplanned venting to the atmosphere and best management practices were conducted according to your best management practice plan, as required by § 60.5376b(c). If no venting events occurred, the number would be zero. Other reported information required to be submitted where unplanned venting occurs is specified in paragraphs (b)(3)(i)(B)(*1*) and (*2*) of this section.

(*1*) Log of best management practice plan steps used during the unplanned venting to minimize emissions to the maximum extent possible.

(*2*) The number of liquids unloading events during the year where deviations from your best management practice plan occurred, the date and time the deviation began, the duration of the deviation in hours, documentation of why best management practice plan steps were not followed, and what steps, in lieu of your best management practice plan steps, were followed to minimize emissions to the maximum extent possible.

(C) The number of liquids unloading events where unplanned emissions are vented to the atmosphere during a gas well liquids unloading operation where you complied with best management practices to minimize emissions to the maximum extent possible.

(ii) For each well affected facility where all gas well liquids unloading operations comply with § 60.5376b(b) and (c) best management practices, your annual report must include the information specified in paragraphs (b)(3)(ii)(A) through (E) of this section.

(A) Identification of each well affected facility that conducts a gas well liquids unloading during the reporting period.

(B) Number of liquids unloading events conducted during the reporting period.

(C) Log of best management practice plan steps used during the reporting period to minimize emissions to the maximum extent possible.

(D) The number of liquids unloading events during the year that best management practices were conducted according to your best management practice plan.

(E) The number of liquids unloading events during the year where deviations from your best management practice plan occurred, the date and time the deviation began, the duration of the deviation in hours, documentation of why best management practice plan steps were not followed, and what steps, in lieu of your best management practice plan steps, were followed to minimize emissions to the maximum extent possible.

(4) For each associated gas well subject to § 60.5377b, your annual report is required to include the applicable information specified in paragraphs (b)(4)(i) through (vi) of this section, as applicable.

(i) For each associated gas well that complies with § 60.5377b(a)(1), (2), (3), or (4) your annual report is required to include the information specified in paragraphs (b)(4)(i)(A) and (B) of this section.

(A) An identification of each associated gas well constructed, modified, or reconstructed during the reporting period that complies with § 60.5377b(a)(1), (2), (3), or (4).

(B) The information specified in paragraphs (b)(2)(i)(B)(*1*) through (*3*) of this section for each incident when the associated gas was temporarily routed to a flare or control device in accordance with § 60.5377b(d)

(*1*) The reason in § 60.5377b(d)(1), (2), (3), or (4) for each incident.

(*2*) The start date and time of each incident of routing associated gas to the flare or control device, along with the total duration in hours of each incident.

(*3*) Documentation that all CVS requirements specified in § 60.5411b(a) and (c) and all applicable flare or control device requirements specified in § 60.5412b were met during each period when the associated gas is routed to the flare or control device.

(ii) For all instances where you temporarily vent the associated gas in accordance with § 60.5377b(e), you must report the information specified in paragraphs (b)(4)(ii)(A) through (D) of this section. This information is required to be reported if you are routinely complying with § 60.5377b(a) or § 60.5377b(f) or temporarily complying with § 60.5377b(d). In addition to this information for each incident, you must report the cumulative duration in hours of venting incidents and the cumulative VOC and methane emissions in pounds for all incidents in the calendar year.

(A) The reason in § 60.5377b(e)(1), (2), or (3) for each incident.

(B) The start date and time of each incident of venting the associated gas, along with the total duration in hours of each incident.

(C) The VOC and methane emissions in pounds that were emitted during each incident.

(D) The total duration of venting for all incidents in the year, along with the cumulative VOC and methane emissions in pounds that were emitted.

(iii) For each associated gas well that complies with the requirements of § 60.5377b(f) your annual report must include the information specified in paragraphs (b)(4)(iii)(A) through (E) of this section. The information in paragraphs (b)(4)(iii)(A) and (B) of this section is only required in the initial annual report.

(A) An identification of each associated gas well that commenced construction between May 7, 2024 and May 7, 2026. This identification must include the certification of why it is infeasible to comply with § 60.5377b(a)(1), (2), (3), or (4) in accordance with § 60.5377b(g).

(B) An identification of each associated gas well that commenced construction between December 6, 2022, and May 7, 2024. This identification must include the certification of why it is infeasible to comply with § 60.5377b(a)(1), (2), (3), or (4) in accordance with § 60.5377b(g).

(C) An identification of each associated gas well modified or reconstructed during the reporting period that complies by routing the gas to a control device that reduces VOC and methane emissions by at least 95.0 percent. This identification must include the certification of why it is infeasible to comply with § 60.5377b(a)(1), (2), (3), or (4) in accordance with § 60.5377b(g).

(D) For each associated gas well that was constructed, modified or reconstructed in a previous reporting period that complies by routing the gas to a control device that reduces VOC and methane emissions by at least 95.0 percent, a re-certification of why it is infeasible to comply with § 60.5377b(a)(1), (2), (3), or (4) in accordance with § 60.5377b(g).

(E) The information specified in paragraphs (b)(11)(i) through (iv) of this section.

(iv) If you comply with § 60.5377b(f) with a control device, identification of the associated gas well using the control device and the information in paragraph (b)(11)(v) of this section.

(v) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(vi) For each deviation recorded as specified in paragraph (c)(3)(v) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(5) For each wet seal centrifugal compressor affected facility, the information specified in paragraphs (b)(5)(i) through (v) of this section. For each self-contained wet seal centrifugal compressor, Alaska North Slope centrifugal compressor equipped with sour seal oil separator and capture system, or dry seal centrifugal compressor affected facility, the information specified in paragraphs (b)(5)(vi) through (ix) of this section.

(i) An identification of each centrifugal compressor constructed, modified, or reconstructed during the reporting period.

(ii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(4) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iii) If required to comply with § 60.5380b(a)(2), the information specified in paragraphs (b)(11)(i) through (iv) of this section.

(iv) If complying with § 60.5380b(a)(1) with a control device, identification of the centrifugal compressor with the control device and the information in paragraph (b)(11)(v) of this section.

(v) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(vi) If complying with § 60.5380b(a)(4) or (5) for a self-contained wet seal centrifugal compressor, Alaska North Slope centrifugal compressor equipped with sour seal oil separator and capture system, or dry seal centrifugal compressor requirements, the cumulative number of hours of operation since initial startup, since May 7, 2024, or since the previous volumetric flow rate emissions measurement, as applicable, which have elapsed prior to conducting your volumetric flow rate emission measurement or emissions screening.

(vii) A description of the method used and the results of the volumetric emissions measurement or emissions screening, as applicable.

(viii) Number and type of seals on delay of repair and explanation for each delay of repair.

(ix) Date of planned shutdown(s) that occurred during the reporting period if there are any seals that have been placed on delay of repair.

(6) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(6)(i) through (vii) of this section, as applicable.

(i) The cumulative number of hours of operation since initial startup, since May 7, 2024, or since the previous volumetric flow rate measurement, or since the previous reciprocating compressor rod packing replacement, as applicable, which have elapsed prior to conducting your volumetric flow rate measurement or emissions screening. Alternatively, a statement that emissions from the rod packing are being routed to a process or control device through a closed vent system.

(ii) If applicable, for each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(5)(i) of this section, the date and time the deviation began, duration of the deviation in hours and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iii) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(iv) If complying with § 60.5385b(d), the information in paragraphs (b)(11)(i) through (iv) of this section.

(v) Number and type of rod packing replacements/repairs on delay of repair and explanation for each delay of repair.

(vi) Date of planned shutdown(s) that occurred during the reporting period if there are any rod packing replacements/repairs that have been placed on delay of repair.

(vii) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(7) For each process controller affected facility, the information specified in paragraphs (b)(7)(i) through (iii) of this section in your initial annual report and in subsequent annual reports for each process controller affected facility that is constructed, modified, or reconstructed during the reporting period. Each annual report must contain the information specified in paragraphs (b)(7)(iv) through (x) of this section for each process controller affected facility.

(i) An identification of each process controller that is driven by natural gas, as required by § 60.5390b(d), that allows traceability to the records required in paragraph (c)(6)(i) of this section.

(ii) For each process controller in the affected facility complying with § 60.5390b(a), you must report the information specified in paragraphs (b)(7)(ii)(A) and (B) of this section, as applicable.

(A) An identification of each process controller complying with § 60.5390b(a) by routing the emissions to a process.

(B) An identification of each process controller complying with § 60.5390b(a) by using a self-contained natural gas-driven process controller.

(iii) For each process controller affected facility located at a site in Alaska that does not have access to electrical power and that complies with § 60.5390b(b), you must report the information specified in paragraphs (b)(7)(iii)(A), (B), or (C) of this section, as applicable.

(A) For each process controller complying with § 60.5390b(b)(1) process controller bleed rate requirements, you must report the information specified in paragraphs (b)(7)(iii)(A)(*1*) and (*2*) of this section.

(*1*) The identification of process controllers designed and operated to achieve a bleed rate less than or equal to 6 scfh.

(*2*) Where necessary to meet a functional need, the identification and demonstration why it is necessary to use a process controller with a natural gas bleed rate greater than 6 scfh.

(B) An identification of each intermittent vent process controller complying with the requirements in paragraph § 60.5390b(b)(2).

(C) An identification of each process controller complying with the requirements in § 60.5390b(b) by routing emissions to a control device in accordance with § 60.5390b(b)(3).

(iv) Identification of each process controller which changes its method of compliance during the reporting period and the applicable information specified in paragraphs (b)(7)(v) through (ix) of this section for the new method of compliance.

(v) For each process controller in the affected facility complying with the requirements of § 60.5390b(a) by routing the emissions to a process, you must report the information specified in (b)(11)(i) through (iii) of this section.

(vi) For each process controller in the affected facility complying with the requirements of § 60.5390b(a) by using a self-contained natural gas-driven process controller, you must report the information specified in paragraphs (b)(7)(vi)(A) and (B) of this section.

(A) Dates of each inspection required under § 60.5416b(b); and

(B) Each defect or leak identified during each natural gas-driven-self-contained process controller system inspection, and the date of repair or date of anticipated repair if repair is delayed.

(vii) For each process controller in the affected facility complying with the requirements of § 60.5390b(b)(2), you must report the information specified in paragraphs (b)(7)(vii)(A) and (B) of this section.

(A) Dates and results of the intermittent vent process controller monitoring required by § 60.5390b(b)(2)(ii).

(B) For each instance in which monitoring identifies emissions to the atmosphere from an intermittent vent controller during idle periods, the date of repair or replacement or the date of anticipated repair or replacement if the repair or replacement is delayed, and the date and results of the re-survey after repair or replacement.

(viii) For each process controller affected facility complying with § 60.5390b(b)(3) by routing emissions to a control device, you must report the information specified in paragraph (b)(11) of this section.

(ix) For each deviation that occurred during the reporting period, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(x) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(7)(ii)(B) and (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(8) For each storage vessel affected facility, the information in paragraphs (b)(8)(i) through (x) of this section.

(i) An identification, including the location, of each storage vessel affected facility, including those for which construction, modification, or reconstruction commenced during the reporting period, and those provided in previous reports. The location of the storage vessel affected facility shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the methane and VOC emission rate determination according to § 60.5365b(e)(1) for each tank battery that became an affected facility during the reporting period or is returned to service during the reporting period.

(iii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(7)(iii) of this section, the date and time the deviation began, duration of the deviation in hours and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iv) For each storage vessel affected facility constructed, modified, reconstructed, or returned to service during the reporting period complying with § 60.5395b(a)(2) with a control device, report the identification of the storage vessel affected facility with the control device and the information in paragraph (b)(11)(v) of this section.

(v) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(vi) If required to comply with § 60.5395b(b)(1), the information in paragraphs (b)(11)(i) through (iv) of this section.

(vii) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in § 60.5395b(c)(1)(ii), including the date the storage vessel affected facility was removed from service. You must identify each storage vessel that that is removed from service from a storage vessel affected facility during the reporting period as specified in § 60.5395b(c)(2)(iii), including identifying the impacted storage vessel affected facility and the date each storage vessel was removed from service.

(viii) You must identify each storage vessel affected facility or portion of a storage vessel affected facility returned to service during the reporting period as specified in § 60.5395b(c)(4), including the date the storage vessel affected facility or portion of a storage vessel affected facility was returned to service.

(ix) You must identify each storage vessel affected facility that no longer complies with § 60.5395b(a)(3) and instead complies with § 60.5395b(a)(2). You must identify whether the change in the method of compliance was due to fracturing or refracturing or whether the change was due to an increase in the monthly emissions determination. If the change was due to an increase in the monthly emissions determination, you must provide documentation of the emissions rate. You must identify the date that you complied with § 60.5395b(a)(2) and must submit the information in (b)(8)(iii) through (vii) of this section.

(x) You must submit a statement that you are complying with § 60.112b(a)(1) or (2), if applicable, in your initial annual report.

(9) For the fugitive emissions components affected facility, report the information specified in paragraphs (b)(9)(i) through (v) of this section, as applicable.

(i)

(A) Designation of the type of site (*i.e.,* well site, centralized production facility, or compressor station) at which the fugitive emissions components affected facility is located.

(B) For the fugitive emissions components affected facility at a well site or centralized production facility that became an affected facility during the reporting period, you must include the date of the startup of production or the date of the first day of production after modification. For the fugitive emissions components affected facility at a compressor station that became an affected facility during the reporting period, you must include the date of startup or the date of modification.

(C) For the fugitive emissions components affected facility at a well site, you must specify what type of well site it is (*i.e.,* single wellhead only well site, small wellsite, multi-wellhead only well site, or a well site with major production and processing equipment).

(D) For the fugitive emissions components affected facility at a well site where during the reporting period you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, you must include the date of the change to status as a wellhead only well site.

(E) For the fugitive emissions components affected facility at a well site where you previously reported under paragraph (b)(9)(i)(D) of this section the removal of all major production and processing equipment and during the reporting period major production and processing equipment is added back to the well site, the date that the first piece of major production and processing equipment is added back to the well site.

(F) For the fugitive emissions components affected facility at a well site where during the reporting period you undertake well closure requirements, the date of the cessation of production from all wells at the well site, the date you began well closure activities at the well site, and the dates of the notifications submitted in accordance with paragraph (a)(4) of this section.

(ii) For each fugitive emissions monitoring survey performed during the annual reporting period, the information specified in paragraphs (b)(9)(ii)(A) through (G) of this section.

(A) Date of the survey.

(B) Monitoring instrument or, if the survey was conducted by AVO methods, notation that AVO was used.

(C) Any deviations from the monitoring plan elements under § 60.5397b(c)(1), (2), and (7), (c)(8)(i), or (d) or a statement that there were no deviations from these elements of the monitoring plan.

(D) Number and type of components for which fugitive emissions were detected.

(E) Number and type of fugitive emissions components that were not repaired as required in § 60.5397b(h).

(F) Number and type of fugitive emission components (including designation as difficult-to-monitor or unsafe-to-monitor, if applicable) on delay of repair and explanation for each delay of repair.

(G) Date of planned shutdown(s) that occurred during the reporting period if there are any components that have been placed on delay of repair.

(iii) For the fugitive emissions components affected facility complying with an alternative fugitive emissions standard under § 60.5399b, in lieu of the information specified in paragraphs (b)(9)(i) and (ii) of this section, you must provide the information specified in paragraphs (b)(9)(iii)(A) through (C) of this section.

(A) The alternative standard with which you are complying.

(B) The site-specific reports specified by the specific alternative fugitive emissions standard, submitted in the format in which they were submitted to the state, local, or Tribal authority. If the report is in hard copy, you must scan the document and submit it as an electronic attachment to the annual report required in paragraph (b) of this section.

(C) If the report specified by the specific alternative fugitive emissions standard is not site-specific, you must submit the information specified in paragraphs (b)(9)(i) and (ii) of this section for each individual site complying with the alternative standard.

(iv) For well closure activities which occurred during the reporting period, the information in paragraphs (b)(9)(iv)(A) and (B) of this section.

(A) A status report with dates for the well closure activities schedule developed in the well closure plan. If all steps in the well closure plan are completed in the reporting period, the date that all activities are completed.

(B) If an OGI survey is conducted during the reporting period, the information in paragraphs (b)(9)(iv)(B)(*1*) through (*3*) of this section.

(*1*) Date of the OGI survey.

(*2*) Monitoring instrument used.

(*3*) A statement that no fugitive emissions were found, or if fugitive emissions were found, a description of the steps taken to eliminate those emissions, the date of the resurvey, the results of the resurvey, and the date of the final resurvey which detected no emissions.

(v) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(9)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(10) For each pump affected facility, the information specified in paragraphs (b)(10)(i) through (iv) of this section in your initial annual report and in subsequent annual reports for each pump affected facility that is constructed, modified, or reconstructed during the reporting period. Each annual report must contain the information specified in paragraphs (b)(10)(v) through (ix) of this section for each pump affected facility.

(i) The identification of each of your pumps that are driven by natural gas, as required by § 60.5393b(a) that allows traceability to the records required by paragraph (c)(15)(i) of this section.

(ii) For each pump affected facility for which there is a control device on site but it does not achieve a 95.0 percent emissions reduction, the certification that there is a control device available on site but it does not achieve a 95.0 percent emissions reduction required under § 60.5393b(b)(3). You must also report the emissions reduction percentage the control device is designed to achieve.

(iii) For each pump affected facility for which there is no control device or vapor recovery unit on site, the certification required under § 60.5393b(b)(4) that there is no control device or vapor recovery unit on site.

(iv) For each pump affected facility for which it is technically infeasible to route the emissions to a process or control device, the certification of technically infeasibility required under § 60.5393b(b)(5).

(v) For any pump affected facility which has previously reported as required under paragraph (b)(10)(i) through (iv) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the pump affected facility and the date that the pump affected facility meets one of the change conditions described in paragraphs (b)(10)(v)(A), (B), or (C) of this section.

(A) If you install a control device or vapor recovery unit, you must report that a control device or vapor recovery unit has been added to the site and that the pump affected facility now is required to comply with § 60.5393b(b)(1) or (3), as applicable.

(B) If your pump affected facility previously complied with § 60.5393b(b)(1) or (3) by routing emissions to a process or a control device and the process or control device is subsequently removed from the site or is no longer available such that there is no ability to route the emissions to a process or control device at the site, or that it is not technically feasible to capture and route the emissions to another control device or process located on site, report that you are no longer complying with the applicable requirements of § 60.5393b(b)(1) or (3) and submit the information provided in paragraphs (b)(10)(v)(B)(*1*) or (*2*) of this section.

(*1*) Certification that there is no control device or vapor recovery unit on site.

(*2*) Certification of the engineering assessment that it is technically infeasible to capture and route the emissions to another control device or process located on site.

(C) If any pump affected facility or individual natural gas-driven pump changes its method of compliance during the reporting period other than for the reasons specified in paragraphs (10)(v)(A) and (B) of this section, identify the new compliance method for each natural gas-driven pump within the affected facility which changes its method of compliance during the reporting period and provide the applicable information specified in paragraphs (b)(10)(ii) through (iv) and (vi) through (viii) of this section for the new method of compliance.

(vi) For each pump affected facility complying with the requirements of § 60.5393b(a), (b)(1), or (b)(3) by routing the emissions to a process, you must report the information specified in paragraphs (b)(11)(i) through (iv) of this section.

(vii) For each pump affected facility complying with the requirements of § 60.5393b(b)(1) or (3) by routing the emissions to a control device, you must report the information required under paragraph (b)(11) of this section.

(viii) For each deviation that occurred during the reporting period, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(ix) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(11) For each well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment affected facility which uses a closed vent system routed to a control device to meet the emissions reduction standard, you must submit the information in paragraphs (b)(11)(i) through (v) of this section. For each reciprocating compressor, process controller, pump, storage vessel, or process unit equipment which uses a closed vent system to route to a process, you must submit the information in paragraphs (b)(11)(i) through (iv) of this section. For each centrifugal compressor, reciprocating compressor, and storage vessel equipped with a cover, you must submit the information in paragraphs (b)(11)(i) and (ii) of this section.

(i) Dates of each inspection required under § 60.5416b(a) and (b).

(ii) Each defect or emissions identified during each inspection and the date of repair or the date of anticipated repair if the repair is delayed.

(iii) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416b(a)(4).

(iv) You must submit the certification signed by the qualified professional engineer or in-house engineer according to § 60.5411b(c) for each closed vent system routing to a control device or process in the reporting year in which the certification is signed.

(v) If you comply with the emissions standard for your well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment affected facility with a control device, the information in paragraphs (b)(11)(v)(A) through (L) of this section, unless you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d). If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), the information in paragraphs (b)(11)(v)(A) through (C) and (L) through (P) of this section.

(A) Identification of the control device.

(B) Make, model, and date of installation of the control device.

(C) Identification of the affected facility controlled by the device.

(D) For each continuous parameter monitoring system used to demonstrate compliance for the control device, a unique continuous parameter monitoring system identifier and the make, model number, and date of last calibration check of the continuous parameter monitoring system.

(E) For each instance where there is a deviation of the control device in accordance with § 60.5417b(g)(1) through (3) or (g)(5) through (7) include the date and time the deviation began, the duration of the deviation in hours, the type of the deviation (*e.g.,* NHV operating limit, lack of pilot or combustion flame, condenser efficiency, bypass line flow, visible emissions), and cause of the deviation.

(F) For each instance where there is a deviation of the continuous parameter monitoring system in accordance with § 60.5417b(g)(4) include the date and time the deviation began, the duration of the deviation in hours, and cause of the deviation.

(G) For each visible emissions test following return to operation from a maintenance or repair activity, the date of the visible emissions test or observation of the video surveillance output, the length of the observation in minutes, and the number of minutes for which visible emissions were present.

(H) If a performance test was conducted on the control device during the reporting period, provide the date the performance test was conducted. Submit the performance test report following the procedures specified in paragraph (b)(12) of this section.

(I) If a demonstration of the NHV of the inlet gas to the enclosed combustion device or flare was conducted during the reporting period in accordance with § 60.5417b(d)(8)(iii), an indication of whether this is a re-evaluation of vent gas NHV and the reason for the re-evaluation; the applicable required minimum vent gas NHV; if twice daily samples of the vent stream were taken, the number of hourly average NHV values that are less than 1.2 times the applicable required minimum NHV; if continuous NHV sampling of the vent stream was conducted, the number of hourly average NHV values that are less than the required minimum vent gas NHV; if continuous combustion efficiency monitoring was conducted using an alternative test method approved under § 60.5412b(d), the number of values of the combustion efficiency that were less than 95.0 percent; the resulting determination of whether NHV monitoring is required or not in accordance with § 60.5417b(d)(8)(iii)(D) or (H); and an indication of whether the enclosed combustion device or flare has the potential to receive inert gases, and if so, whether the sampling included periods where the highest percentage of inert gases were sent to the enclosed combustion device or flare.

(J) If a demonstration was conducted in accordance with § 60.5417b(d)(8)(iv) that the maximum potential pressure of units manifolded to an enclosed combustion device or flare cannot cause the maximum inlet flow rate established in accordance with § 60.5417b(f)(1) or a flare tip velocity limit of 18.3 meter/second (60 feet/second) to be exceeded, an indication of whether this is a re-evaluation of the gas flow and the reason for the re-evaluation; the demonstration conducted; and applicable engineering calculations.

(K) For each periodic sampling event conducted under § 60.5417b(d)(8)(iii)(G), provide the date of the sampling, the required minimum vent gas NHV, and the NHV value for each vent gas sample.

(L) For each flare and enclosed combustion device, provide the date each device is observed with OGI in accordance with § 60.5415b(f)(x) and whether uncombusted emissions were present. Provide the date each device was visibly observed during an AVO inspection in accordance with § 60.5415b(f)(x), whether the pilot or combustion flame was lit at the time of observation, and whether the device was found to be operating properly.

(M) An identification of the alternative test method used.

(N) For each instance where there is a deviation of the control device in accordance with § 60.5417b(i)(6)(i) or (iii) through (v) include the date and time the deviation began, the duration of the deviation in hours, the type of the deviation (*e.g.,* NHV_{cz} operating limit, lack of pilot or combustion flame, visible emissions), and cause of the deviation.

(O) For each instance where there is a deviation of the data availability in accordance with § 60.5417b(i)(6)(ii) include the date of each operating day when monitoring data are not available for at least 75 percent of the operating hours.

(P) If no deviations occurred under paragraphs (b)(11)(v)(N) or (O) of this section, a statement that there were no deviations for the control device during the annual report period.

(Q) Any additional information required to be reported as specified by the Administrator as part of the alternative test method approval under § 60.5412b(d).

(12) Within 60 days after the date of completing each performance test (see § 60.8) required by this subpart, except testing conducted by the manufacturer as specified in § 60.5413b(d), you must submit the results of the performance test following the procedures specified in paragraph (d) of this section. Data collected using test methods that are 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, 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.

(13) For combustion control devices tested by the manufacturer in accordance with § 60.5413b(d), an electronic copy of the performance test results required by § 60.5413b(d) shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following website: *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry.*

(14) If you had a super-emitter event during the reporting period, the start date of the super-emitter event, the duration of the super-emitter event in hours, and the affected facility associated with the super-emitter event, if applicable.

(15) You must submit your annual report using the appropriate electronic report template on the Compliance and Emissions Data Reporting Interface (CEDRI) website for this subpart and following the procedure specified in paragraph (d) of this section. If the reporting form specific to this subpart is not available on the CEDRI website at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 60.4. Once the form has been available on the CEDRI website for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The date reporting forms 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.

(c) ***Recordkeeping requirements.*** You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (15) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years. 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.

(1) The records for each well affected facility subject to the well completion operation standards of § 60.5375b, as specified in paragraphs (c)(1)(i) through (vii) of this section, as applicable. For each well affected facility subject to the well completion operations of § 60.5375b, for which you make a claim that the well affected facility is not subject to the requirements for well completions pursuant to § 60.5375b(g), you must maintain the record in paragraph (c)(1)(vi) of this section, only. For each well affected facility which meets the exemption in § 60.5375b(h) for well completion operations (*i.e.,* an existing well is hydraulically refractured), you must maintain the records in paragraph (c)(1)(viii), only. For each well affected facility that routes flowback entirely through one or more production separators that are designed to accommodate flowback, only records of the United States Well Number, the latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983, the Well Completion ID, and the date and time of startup of production are required. For periods where salable gas is unable to be separated, records of the date and time of onset of flowback, the duration and disposition of recovery, the duration of combustion and venting (if applicable), reasons for venting (if applicable), and deviations are required.

(i) Records identifying each well completion operation for each well affected facility.

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375b, including the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(iii) You must maintain the records specified in paragraphs (c)(1)(iii)(A) through (C) of this section.

(A) For each well affected facility required to comply with the requirements of § 60.5375b(a), you must record: The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in § 60.5375b(a)(1)(ii); the date and time of each occurrence of returning to the initial flowback stage under § 60.5375b(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours. In addition, for wells where it is technically infeasible to route the recovered gas as specified in § 60.5375b(a)(1)(ii), you must record the reasons for the claim of technical infeasibility with respect to all four options provided in § 60.5375b(a)(1)(ii).

(B) For each well affected facility required to comply with the requirements of § 60.5375b(f), you must record: Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of combustion; duration of venting; and specific reasons for venting in lieu combustion. The duration must be specified in hours.

(C) For each well affected facility for which you make a claim that it meets the criteria of § 60.5375b(a)(1)(iii)(A), you must maintain the following:

(*1*) The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours.

(*2*) If applicable, records that the conditions of § 60.5375b(a)(1)(iii)(A) are no longer met and that the well completion operation has been stopped and a separator installed. The records shall include the date and time the well completion operation was stopped and the date and time the separator was installed.

(*3*) A record of the claim signed by the certifying official that no liquids collection is at the well site. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(iv) For each well affected facility for which you claim an exception under § 60.5375b(a)(2), you must record: The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each well affected facility required to comply with both § 60.5375b(a)(1) and (2), if you are using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, you must retain the records of the digital photograph as specified in § 60.5410b(a)(4).

(vi) For each well affected facility for which you make a claim that the well affected facility is not subject to the well completion standards according to § 60.5375b(g), you must maintain:

(A) A record of the analysis that was performed in order the make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field;

(B) The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number;

(C) A record of the claim signed by the certifying official. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(vii) For each well affected facility subject to § 60.5375b(f), a record of the well type (*i.e.,* wildcat well, delineation well, or low pressure well (as defined § 60.5430b)) and supporting inputs and calculations, if applicable.

(viii) For each well affected facility which makes a claim it meets the exemption at § 60.5375b(h), a record of the latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing and a record of the claim that the well completion operation requirements of § 60.5375b(a)(1) through (3) were met.

(2) For each gas well liquids unloading operation at your well affected facility that is subject to § 60.5376b(a)(1) or (2), the records of each gas well liquids unloading operation conducted during the reporting period, including the information specified in paragraphs (c)(2)(i) through (iii) of this section, as applicable.

(i) For each gas well liquids unloading operation that complies with § 60.5376b(a)(1) by performing all liquids unloading events without venting of methane and VOC emissions to the atmosphere, comply with the recordkeeping requirements specified in paragraphs (c)(2)(i)(A) and (B) of this section.

ocumentation of your best management practice plan developed under paragraph § 60.5376b(c). You may update your
est management practice plan to include additional steps which meet the criteria in § 60.5376b(c).

 log of each best management practice plan step taken minimize emissions to the maximum extent possible for each gas well liquids unloading event.

ocumentation of each gas well liquids unloading event where deviations from your best management practice plan teps occurred, the date and time the deviation began, the duration of the deviation, documentation of best management ractice plans steps were not followed, and the steps taken in lieu of your best management practice plan steps during hose events to minimize emissions to the maximum extent possible.

ch well affected facility that reduces methane and VOC emissions from well affected facility gas wells that unload s by 95.0 percent by routing emissions to a control device through closed vent system under § 60.5376b(g), you must ain the records in paragraphs (c)(2)(iii)(A) through (E) of this section.

 you comply with the emission reduction standard with a control device, the information for each control device in aragraph (c)(11) of this section.

ecords of the closed vent system inspection as specified paragraph (c)(8) of this section.

ecords of the cover inspections as specified in paragraph (c)(9) of this section.

 applicable, the records of bypass monitoring as specified in paragraph (c)(10) of this section.

ecords of the closed vent system assessment as specified in paragraph (c)(12) of this section.

sociated gas well, you must maintain the applicable records specified in paragraphs (c)(3)(i) or (ii) and (c)(3)(iv) of this

ch associated gas well that complies with the requirements of § 60.5377b(a)(1), (2), (3), or (4), you must keep the ls specified in paragraphs (c)(3)(i)(A) and (B).

ocumentation of the specific method(s) in § 60.5377b(a)(1), (2), (3), or (4) that is used.

or instances where you temporarily route the associated gas to a flare or control device in accordance with § 0.5377b(d), you must keep the records specified in paragraphs (c)(3)(i)(B)(*1*) through (*3*).

1) The reason in § 60.5377b(d)(1), (2), (3), or (4) for each incident.

2) The date of each incident, along with the times when routing the associated gas to the flare or control device started and ended, along with the total duration of each incident.

3) Documentation that all CVS requirements specified in § 60.5411b(a) and (c) and all applicable flare or control device requirements specified in § 60.5412b are met during each period when the associated gas is routed to the flare or control device.

stances where you temporarily vent the associated gas in accordance with § 60.5377b(e), you must keep the records ied in paragraphs (c)(3)(ii)(A) through (D). These records are required if you are routinely complying with § 60.5377b(a) 0.5377b(f) or temporarily complying with § 60.5377b(d).

he reason in § 60.5377b(e)(1), (2), or (3) for each incident.

he date of each incident, along with the times when venting the associated gas started and ended, along with the total uration of each incident.

he VOC and methane emissions that were emitted during each incident.

he cumulative duration of venting incidents and VOC and methane emissions for all incidents in each calendar year.

(iii) For each associated gas well that complies with the requirements of § 60.5377b(f) because it has demonstrated that it is not feasible to comply with § 60.5377b(a)(1), (2), (3), and (4) due to technical reasons in accordance with § 60.5377b(g), records of each annual demonstration and certification of the technical reason that it is not feasible to comply with § 60.5377b(a)(1), (2), (3), and (4) in accordance with § 60.5377b(g).

(iv) For each associated gas well that complies with the requirements of § 60.5377b(f), meet the recordkeeping requirements specified in paragraphs (c)(3)(iv)(A) through (E).

(A) Identification of each instance when associated gas was vented and not routed to a control device that reduces VOC and methane emissions by at least 95.0 percent.

(B) If you comply with the emission reduction standard in § 60.5380b with a control device, the information for each control device in paragraph (c)(11) of this section.

(C) Records of the closed vent system inspection as specified paragraph (c)(8) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must maintain records of the information specified in § 60.5424b.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(10) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(12) of this section.

(v) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(4) For each centrifugal compressor affected facility, you must maintain the records specified in paragraphs (c)(4)(i) through (iii) of this section.

(i) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in § 60.5380b, including a description of each deviation, the date and time each deviation began and the duration of each deviation.

(ii) For each wet seal compressor complying with the emissions reduction standard in § 60.5380b(a)(1), you must maintain the records in paragraphs (c)(4)(ii)(A) through (E) of this section. For each wet seal compressor complying with the alternative standard in § 60.5380b(a)(3) by routing the closed vent system to a process, you must maintain the records in paragraphs (c)(4)(ii)(B) through (E) of this section.

(A) If you comply with the emission reduction standard in § 60.5380b(a)(1) with a control device, the information for each control device in paragraph (c)(11) of this section.

(B) Records of the closed vent system inspection as specified paragraph (c)(8) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must maintain the information specified in § 60.5424b.

(C) Records of the cover inspections as specified in paragraph (c)(9) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (c)(9) of this section, you must maintain the information specified in § 60.5424b.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(10) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(12) of this section.

(iii) For each centrifugal compressor affected facility using a self-contained wet seal compressor, or dry seal compressor complying with the standard in § 60.5380b(a)(4) and (5), you must maintain the records specified in paragraphs (c)(4)(iii)(A) through (H) of this section.

(A) Records of the cumulative number of hours of operation since initial startup, since May 7, 2024, or since the previous volumetric flow rate measurement, as applicable.

(B) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(C) Records for all flow meters, composition analyzers and pressure gauges used to measure volumetric flow rates as specified in paragraphs (c)(4)(iii)(C)(*1*) through (*6*).

(*1*) Description of standard method published by a consensus-based standards organization or industry standard practice.

(*2*) Records of volumetric flow rate emissions calculations conducted according to paragraphs § 60.5380b(a)(5), as applicable.

(*3*) Records of manufacturer's operating procedures and measurement methods.

(*4*) Records of manufacturer's recommended procedures or an appropriate industry consensus standard method for calibration and results of calibration, recalibration, and accuracy checks.

dentification of each compressor seal placed on delay of repair and explanation for each delay of repair.

or each compressor seal or part needed for repair placed on delay of repair because of replacement seal or part unavailability, the operator must document: the date the seal or part was added to the delay of repair list, the date the eplacement seal or part was ordered, the anticipated seal or part delivery date (including any estimated shipment or lelivery date provided by the vendor), and the actual arrival date of the seal or part.

ate of planned shutdowns that occur while there are any seals or parts that have been placed on delay of repair.

ciprocating compressor affected facility, you must maintain the records in paragraphs (c)(5)(i) through (x), and (c)(8), (c))(12) of this section, as applicable. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of ation specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

ch reciprocating compressor affected facility, you must maintain records of deviations in cases where the reciprocating ressor was not operated in compliance with the requirements specified in § 60.5385b, including a description of each ion, the date and time each deviation began and the duration of each deviation in hours.

ds of the date of installation of a rod packing emissions collection system and closed vent system as specified in § 35b(d).

ds of the cumulative number of hours of operation since initial startup, since May 7, 2024, or since the previous etric flow rate measurement, as applicable. Alternatively, a record that emissions from the rod packing are being routed rocess through a closed vent system.

cription of the method used and the results of the volumetric flow rate measurement or emissions screening, as able.

ds for all flow meters, composition analyzers and pressure gauges used to measure volumetric flow rates as specified in raphs (c)(5)(v)(A) through (F).

escription of standard method published by a consensus-based standards organization or industry standard practice.

ecords of volumetric flow rate calculations conducted according to paragraphs § 60.5385b(b) or (c), as applicable.

ecords of manufacturer operating procedures and measurement methods.

ecords of manufacturer's recommended procedures or an appropriate industry consensus standard method for alibration and results of calibration, recalibration, and accuracy checks.

ecords which demonstrate that measurements at the remote location(s) can, when appropriate correction factors are pplied, reliably and accurately represent the actual temperature or total pressure at the flow meter under all expected mbient conditions. You must include the date of the demonstration, the data from the demonstration, the mathematical orrelation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting ngineering calculations. If adjustments were made to the mathematical relationships, a record and description of such djustments.

ecord of each initial calibration or a recalibration which failed to meet the required accuracy specification and the date f the successful recalibration.

hen performance-based volumetric flow rate is exceeded.

te of successful replacement or repair of reciprocating compressor rod packing, including follow-up performance-based etric flow rate measurement to confirm successful repair.

fication of each reciprocating compressor placed on delay of repair because of rod packing or part unavailability and ation for each delay of repair.

ch reciprocating compressor that is placed on delay of repair because of replacement rod packing or part unavailability, erator must document: the date the rod packing or part was added to the delay of repair list, the date the replacement cking or part was ordered, the anticipated rod packing or part delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the rod packing or part.

(x) Date of planned shutdowns that occur while there are any reciprocating compressors that have been placed on delay of repair due to the unavailability of rod packing or parts to conduct repairs.

(6) For each process controller affected facility, you must maintain the records specified in paragraphs (c)(6)(i) through (vii) of this section.

(i) Records identifying each process controller that is driven by natural gas and that does not function as an emergency shutdown device.

(ii) For each process controller affected facility complying with § 60.5390b(a), you must maintain records of the information specified in paragraphs (c)(6)(ii)(A) and (B) of this section, as applicable.

(A) If you are complying with § 60.5390b(a) by routing process controller vapors to a process through a closed vent system, you must report the information specified in paragraphs (c)(6)(ii)(A)(*1*) and (*2*) of this section.

(*1*) An identification of all the natural gas-driven process controllers in the process controller affected facility for which you collect and route vapors to a process through a closed vent system.

(*2*) The records specified in paragraphs (c)(8), (10), and (12) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(B) If you are complying with § 60.5390b(a) by using a self-contained natural gas-driven process controller, you must report the information specified in paragraphs (c)(6)(ii)(B)(*1*) through (*3*) of this section.

(*1*) An identification of each process controller complying with § 60.5390b(a) by using a self-contained natural gas-driven process controller;

(*2*) Dates of each inspection required under § 60.5416b(b); and

(*3*) Each defect or leak identified during each natural gas-driven-self-contained process controller system inspection, and date of repair or date of anticipated repair if repair is delayed.

(iii) For each process controller affected facility complying with the § 60.5390b(b)(1) process controller bleed rate requirements, you must maintain records of the information specified in paragraphs (c)(6)(iii)(A) and (B) of this section.

(A) The identification of process controllers designed and operated to achieve a bleed rate less than or equal to 6 scfh and records of the manufacturer's specifications indicating that the process controller is designed with a natural gas bleed rate of less than or equal to 6 scfh.

(B) Where necessary to meet a functional need, the identification of the process controller and demonstration of why it is necessary to use a process controller with a natural gas bleed rate greater than 6 scfh.

(iv) For each intermittent vent process controller in the affected facility complying with the requirements in paragraphs § 60.5390b(b)(2), you must keep records of the information specified in paragraphs (c)(6)(iv)(A) through (C) of this section.

(A) The identification of each intermittent vent process controller.

(B) Dates and results of the intermittent vent process controller monitoring required by § 60.5390b(b)(2)(ii).

(C) For each instance in which monitoring identifies emissions to the atmosphere from an intermittent vent controller during idle periods, the date of repair or replacement, or the date of anticipated repair or replacement if the repair or replacement is delayed and the date and results of the re-survey after repair or replacement.

(v) For each process controller affected facility complying with § 60.5390b(b)(3), you must maintain the records specified in paragraphs (c)(6)(v)(A) and (B) of this section.

(A) An identification of each process controller for which emissions are routed to a control device.

(B) Records specified in paragraphs (c)(8) and (c)(10) through (13) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(vi) Records of each change in compliance method, including identification of each natural gas-driven process controller which changes its method of compliance, the new method of compliance, and the date of the change in compliance method.

(vii) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(7) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(7)(i) through (vii) of this section.

(i) You must maintain records of the identification and location in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983 of each storage vessel affected facility.

(ii) Records of each methane and VOC emissions determination for each storage vessel affected facility made under § 60.5365b(e) including identification of the model or calculation methodology used to calculate the methane and VOC emission rate.

(iii) For each instance where the storage vessel was not operated in compliance with the requirements specified in § 60.5395b a description of the deviation, the date and time each deviation began, and the duration of the deviation.

(iv) If complying with the emissions reduction standard in § 60.5395b(a)(2), you must maintain the records in paragraphs (c)(7)(iv)(A) through (E) of this section.

(A) If you comply with the emission reduction standard with a control device, the information for each control device in paragraph (c)(11) of this section.

(B) Records of the closed vent system inspection as specified paragraph (c)(8) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(C) Records of the cover inspections as specified in paragraph (c)(9) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (c)(9) of this section, you must provide the information specified in § 60.5424b.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(10) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(12) of this section.

(v) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), records indicating the number of consecutive days that the vessel is located at a site in the crude oil and natural gas source category. If a storage vessel is removed from a site and, within 30 days, is either returned to the site or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(vi) Records of the date that each storage vessel affected facility or portion of a storage vessel affected facility is removed from service and returned to service, as applicable.

(vii) Records of the date that liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility; or the date that you comply with paragraph § 60.5395b(a)(2), following a monthly emissions determination which indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater or methane emissions increase to 14 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, and records of the methane and VOC emissions rate and the model or calculation methodology used to calculate the methane and VOC emission rate.

(8) Records of each closed vent system inspection required under § 60.5416b(a)(1) and (2) and (b) for your well, centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, and process unit equipment affected facility as required in paragraphs (c)(8)(i) through (iv) of this section.

(i) A record of each closed vent system inspection or no identifiable emissions monitoring survey. You must include an identification number for each closed vent system (or other unique identification description selected by you), the date of the inspection, and the method used to conduct the inspection (*i.e.,* visual, AVO, OGI, Method 21 of appendix A-7 to this part).

(ii) For each defect or emissions detected during inspections required by § 60.5416b(a)(1) and (2), or (b) you must record the location of the defect or emissions; a description of the defect; the maximum concentration reading obtained if using Method 21 of appendix A-7 to this part; the indication of emissions detected by AVO if using AVO; the date of detection; the date of each attempt to repair the emissions or defect; the corrective action taken during each attempt to repair the defect; and the date the repair to correct the defect or emissions is completed.

(iii) If repair of the defect is delayed as described in § 60.5416b(b)(6), you must record the reason for the delay and the date you expect to complete the repair.

(iv) Parts of the closed vent system designated as unsafe to inspect as described in § 60.5416b(b)(7) or difficult to inspect as described in § 60.5416b(b)(8), the reason for the designation, and written plan for inspection of that part of the closed vent system.

(9) A record of each cover inspection required under § 60.5416b(a)(3) for your centrifugal compressor, reciprocating compressor, or storage vessel as required in paragraphs (c)(9)(i) through (iv) of this section.

(i) A record of each cover inspection. You must include an identification number for each cover (or other unique identification description selected by you), the date of the inspection, and the method used to conduct the inspection (*i.e.,* AVO, OGI, Method 21 of appendix A-7 to this part).

(ii) For each defect detected during the inspection you must record the location of the defect; a description of the defect, the date of detection, the maximum concentration reading obtained if using Method 21 of appendix A-7 to this part; the indication of emissions detected by AVO if using AVO; the date of each attempt to repair the defect; the corrective action taken during each attempt to repair the defect; and the date the repair to correct the defect is completed.

(iii) If repair of the defect is delayed as described in § 60.5416b(b)(6), you must record the reason for the delay and the date you expect to complete the repair.

(iv) Parts of the cover designated as unsafe to inspect as described in § 60.5416b(b)(7) or difficult to inspect as described in § 60.5416b(b)(8), the reason for the designation, and written plan for inspection of that part of the cover.

(10) For each bypass subject to the bypass requirements of § 60.5416b(a)(4), you must maintain a record of the following, as applicable: readings from the flow indicator; each inspection of the seal or closure mechanism; the date and time of each instance the key is checked out; date and time of each instance the alarm is sounded.

(11) Records for each control device used to comply with the emission reduction standard in § 60.5377b(b) for associated gas wells, § 60.5380b(a)(1) for centrifugal compressor affected facilities, § 60.5385b(d)(2) for reciprocating compressor affected facilities, § 60.5390b(b)(3) for your process controller affected facility in Alaska, § 60.5393b(b)(1) for your pump affected facility, § 60.5395b(a)(2) for your storage vessel affected facility, § 60.5376b(f) for well affected facility gas well liquids unloading, or § 60.5400b(f) or 60.5401b(e) for your process equipment affected facility, as required in paragraphs (c)(11)(i) through (viii) of this section. If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), keep records of the information in paragraphs (c)(11)(ix) of this section, in lieu of the records required by paragraphs (c)(11)(i) through (iv) and (vi) through (viii) of this section.

(i) For a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e), keep records of the information in paragraphs (c)(11)(i)(A) through (E) of this section, in addition to the records in paragraphs (c)(11)(ii) through (ix) of this section, as applicable.

(A) Serial number of purchased device and copy of purchase order.

(B) Location of the affected facility associated with the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(C) Minimum and maximum inlet gas flow rate specified by the manufacturer.

(D) Records of the maintenance and repair log as specified in § 60.5413b(e)(4), for all inspection, repair, and maintenance activities for each control device failing the visible emissions test.

(E) Records of the manufacturer's written operating instructions, procedures, and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(ii) For all control devices, keep records of the information in paragraphs (c)(11)(ii)(A) through (G) of this section, as applicable.

(A) Make, model, and date of installation of the control device, and identification of the affected facility controlled by the device.

(B) Records of deviations in accordance with § 60.5417b(g)(1) through (7), including a description of the deviation, the date and time the deviation began, the duration of the deviation, and the cause of the deviation.

(C) The monitoring plan required by § 60.5417b(c)(2).

(D) Make and model number of each continuous parameter monitoring system.

(E) Records of minimum and maximum operating parameter values, continuous parameter monitoring system data (including records that the pilot or combustion flame is present at all times), calculated averages of continuous parameter monitoring system data, and results of all compliance calculations.

(F) Records of continuous parameter monitoring system equipment performance checks, system accuracy audits, performance evaluations, or other audit procedures and results of all inspections specified in the monitoring plan in accordance with § 60.5417b(c)(2). Records of calibration gas cylinders, if applicable.

(G) Periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities Records of repairs on the monitoring system.

(iii) For each carbon adsorption system, records of the schedule for carbon replacement as determined by the design analysis requirements of § 60.5413b(c)(2) and (3) and records of each carbon replacement as specified in § 60.5412b(c)(1) and § 60.5415b(f)(1)(viii).

(iv) For enclosed combustion devices and flares, records of visible emissions observations as specified in paragraph (c)(11)(iv)(A) or (B) of this section.

(A) Records of observations with Method 22 of appendix A-7 to this part, including observations required following return to operation from a maintenance or repair activity, which include: company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in Method 22 of appendix A-7 to this part.

(B) If you monitor visible emissions with a video surveillance camera, location of the camera and distance to emission source, records of the video surveillance output, and documentation that an operator looked at the feed daily, including the date and start time of observation, the length of observation, and length of time visible emissions were present.

(v) For enclosed combustion devices and flares, video of the OGI inspection conducted in accordance with § 60.5415b(f)(x). Records documenting each enclosed combustion device and flare was visibly observed during each inspection conducted under § 60.5397b using AVO in accordance with § 60.5415b(f)(x).

(vi) For enclosed combustion devices and flares, records of each demonstration of the NHV of the inlet gas to the enclosed combustion device or flare conducted in accordance with § 60.5417b(d)(8)(iii). For each re-evaluation of the NHV of the inlet gas, records of process changes and explanation of the conditions that led to the need to re-evaluation the NHV of the inlet gas. For each demonstration, record information on whether the enclosed combustion device or flare has the potential to receive inert gases, and if so, the highest percentage of inert gases that can be sent to the enclosed combustion device or flare and the highest percent of inert gases sent to the enclosed combustion device or flare during the NHV demonstration. Records of periodic sampling conducted under § 60.5417b(d)(8)(iii)(G).

(vii) For enclosed combustion devices and flares, if you use a backpressure regulator valve, the make and model of the valve, date of installation, and record of inlet flow rating. Maintain records of the engineering evaluation and manufacturer specifications that identify the pressure set point corresponding to the minimum inlet gas flow rate, the annual confirmation that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications, and the annual confirmation that the backpressure regulator valve fully closes when not in open position.

(viii) For enclosed combustion devices and flares, records of each demonstration required under § 60.5417b(d)(8)(iv).

(ix) If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), keep records of the information in paragraphs (c)(11)(ix)(A) through (H) of this section, in lieu of the records required by paragraphs (c)(11)(i) through (iv) and (c)(11)(vi) through (viii) of this section.

(A) An identification of the alternative test method used.

(B) Data recorded at the intervals required by the alternative test method.

(C) Monitoring plan required by § 60.5417(i)(2).

(D) Quality assurance and quality control activities conducted in accordance with the alternative test method.

(E) If required by § 60.5412b(d)(4) to conduct visible emissions observations, records required by paragraph (c)(11)(iv) of this section.

(F) If required by § 60.5412b(d)(5) to conduct pilot or combustion flame monitoring, record indicating the presence of a pilot or combustion flame and periods when the pilot or combustion flame is absent.

(G) For each instance where there is a deviation of the control device in accordance with § 60.5417b(i)(6)(i) through (v), the date and time the deviation began, the duration of the deviation in hours, and cause of the deviation.

(H) Any additional information required to be recorded as specified by the Administrator as part of the alternative test method approval under § 60.5412b(d).

(12) For each closed vent system routing to a control device or process, the records of the assessment conducted according to § 60.5411b(c):

(i) A copy of the assessment conducted according to § 60.5411b(c)(1); and

(ii) A copy of the certification according to § 60.5411b(c)(1)(i) and (ii).

(13) A copy of each performance test submitted under paragraphs (b)(12) or (13) of this section.

(14) For the fugitive emissions components affected facility, maintain the records identified in paragraphs (c)(14)(i) through (viii) of this section.

(i) The date of the startup of production or the date of the first day of production after modification for the fugitive emissions components affected facility at a well site and the date of startup or the date of modification for the fugitive emissions components affected facility at a compressor station.

(ii) For the fugitive emissions components affected facility at a well site, you must maintain records specifying what type of well site it is (*i.e.,* single wellhead only well site, small wellsite, multi-wellhead only well site, or a well site with major production and processing equipment.)

(iii) For the fugitive emissions components affected facility at a well site where you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, record the date the well site completes the removal of all major production and processing equipment from the well site, and, if the well site is still producing, record the well ID or separate tank battery ID receiving the production from the well site. If major production and processing equipment is subsequently added back to the well site, record the date that the first piece of major production and processing equipment is added back to the well site.

perating mode of each compressor (*i.e.,* operating, standby pressurized, and not operating-depressurized modes) at the tation at the time of the survey.

ny deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

ecords of calibrations for the instrument used during the monitoring survey.

ocumentation of each fugitive emission detected during the monitoring survey, including the information specified in aragraphs (c)(14)(v)(I)(*1*) through (*9*) of this section.

1) Location of each fugitive emission identified.

2) Type of fugitive emissions component, including designation as difficult-to-monitor or unsafe-to-monitor, if applicable.

3) If Method 21 of appendix A-7 to this part is used for detection, record the component ID and instrument reading.

4) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph or video must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (*e.g.,* the latitude and longitude of the component or by other descriptive landmarks visible in the picture). The digital photograph or identification (*e.g.,* tag) may be removed after the repair is completed, including verification of repair with the resurvey.

5) The date of first attempt at repair of the fugitive emissions component(s).

6) The date of successful repair of the fugitive emissions component, including the resurvey to verify repair and instrument used for the resurvey.

7) Identification of each fugitive emission component placed on delay of repair and explanation for each delay of repair.

8) For each fugitive emission component placed on delay of repair for reason of replacement component unavailability, the operator must document: the date the component was added to the delay of repair list, the date the replacement fugitive component or part thereof was ordered, the anticipated component delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the component.

9) Date of planned shutdowns that occur while there are any components that have been placed on delay of repair.

e fugitive emissions components affected facility complying with an alternative means of emissions limitation under § 99b, you must maintain the records specified by the specific alternative fugitive emissions standard for a period of at 5 years.

ell closure activities, you must maintain the information specified in paragraphs (c)(14)(vii)(A) through (G) of this section.

he well closure plan developed in accordance with § 60.5397b(l) and the date the plan was submitted.

he notification of the intent to close the well site and the date the notification was submitted.

he date of the cessation of production from all wells at the well site.

he date you began well closure activities at the well site.

ach status report for the well closure activities reported in paragraph (b)(9)(iv)(A) of this section.

ach OGI survey reported in paragraph (b)(9)(iv)(B) of this section including the date, the monitoring instrument used, and he results of the survey or resurvey.

he final OGI survey video demonstrating the closure of all wells at the site. The video must include the date that the ideo was taken and must identify the well site location by latitude and longitude.

(viii) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (c)(14)(iv) and (v) of this section, you must maintain the records specified in § 60.5424b.

(15) For each pump affected facility, you must maintain the records identified in paragraphs (c)(15)(i) through (ix) of this section.

(i) Identification of each pump that is driven by natural gas and that is in operation 90 days or more per calendar year.

(ii) If you are complying with § 60.5393b(a) or (b)(1) by routing pump vapors to a process through a closed vent system, identification of all the pumps in the pump affected facility for which you collect and route vapors to a process through a closed vent system and the records specified in paragraphs (c)(8), (10), and (12) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(iii) If you are complying with § 60.5393b(b)(1) by routing pump vapors to control device achieving a 95.0 percent reduction in methane and VOC emissions, you must keep the records specified in paragraphs (c)(8) and (10) through (c)(13) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(iv) If you are complying with § 60.5393b(b)(3) by routing pump vapors to control device achieving less than a 95.0 percent reduction in methane and VOC emissions, you must maintain records of the certification that there is a control device on site but it does not achieve a 95.0 percent emissions reduction and a record of the design evaluation or manufacturer's specifications which indicate the percentage reduction the control device is designed to achieve.

(v) If you have less than three natural gas-driven diaphragm pumps in the pump affected facility, and you do not have a vapor recovery unit or control device installed on site by the compliance date, you must retain a record of your certification required under § 60.5393b(b)(4), certifying that there is no vapor recovery unit or control device on site. If you subsequently install a control device or vapor recovery unit, you must maintain the records required under paragraphs (c)(15)(ii), (iii) or (iv) of this section, as applicable.

(vi) If you determine, through an engineering assessment, that it is technically infeasible to route the pump affected facility emissions to a process or control device, you must retain records of your demonstration and certification that it is technically infeasible as required under § 60.5393b(b)(5).

(vii) If the pump is routed to a control device that is subsequently removed from the location or is no longer available such that there is no option to route to a control device, you are required to retain records of this change and the records required under paragraph (c)(15)(vi) of this section.

(viii) Records of each change in compliance method, including identification of each natural gas-driven pump which changes its method of compliance, the new method of compliance, and the date of the change in compliance method.

(ix) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(d) ***Electronic reporting.*** If you are required to submit notifications or reports following the procedure specified in this paragraph (d), you must submit notifications or 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 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 or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(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 (d).

(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. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Oil and Natural Gas 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, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. ERT files should be sent to the secondary attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the secondary attention of the Oil and Natural Gas Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(e) ***Claims of EPA system outage.*** If you are required to electronically submit a notification or report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (e)(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.

(f) ***Claims of force majeure.*** If you are required to electronically submit a report or notification through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that requirement. To assert a claim of *force majeure,* you must meet the requirements outlined in paragraphs (f)(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.

§ 60.5421b What are my additional recordkeeping requirements for process unit equipment affected facilities?

You must maintain a record of each equipment leak monitoring inspection and each leak identified under § 60.5400b and § 60.5401b as specified in paragraphs (b)(1) through (16) of this section. The record must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained 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.

(a) You may comply with the recordkeeping requirements for multiple process unit equipment affected facilities in one recordkeeping system if the system identifies each record by each facility.

(b) You must maintain the monitoring inspection records specified in paragraphs (b)(1) through (16) of this section.

(1) Equipment Identification. Note that connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

(2) Date and start and end times of the monitoring inspection.

(3) Inspector name.

(4) Leak determination method used for the monitoring inspection (*i.e.,* OGI, Method 21, or AVO).

(5) Monitoring instrument identification (OGI and Method 21 only).

(6) Type of equipment monitored.

(7) Process unit identification.

(8) The records specified in Section 12 of appendix K of this part, for each monitoring inspection conducted with OGI.

(9) The records in paragraph (b)(9)(i) through (vii), for each monitoring inspection conducted with Method 21 of appendix A-7 to this part.

(i) Instrument reading.

(ii) Date and time of instrument calibration and initials of operator performing the calibration.

(iii) Calibration gas cylinder identification, certification date, and certified concentration.

(iv) Instrument scale used.

(v) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A-7 to this part.

(vi) Results of the daily calibration drift assessment.

(vii) If you make your own calibration gas, a description of the procedure used.

(10) For visual inspections of pumps in light liquid service, keep the records specified in paragraphs (b)(10)(i) through (iii), for each monitored equipment:

(i) Date of inspection.

(ii) Inspector name.

(iii) Result of inspection (*i.e.,* visual indications of liquids dripping from the pump seal or no visual indications of liquids dripping from the pump seal).

(11) For each leak detected, the records specified in paragraphs (b)(11)(i) through (v) of this section:

(i) The instrument and operator identification numbers and the process unit and equipment identification numbers. For leaks identified via AVO methods, enter the specific sensory method for instrument identification number.

(ii) The date the leak was detected.

(iii) For each attempt to repair the leak, record:

(A) The date.

(B) The repair method applied.

(C) Indication of whether a leak was still detected following each attempt to repair the leak.

(vi) The date of successful repair of the leak and the method of monitoring used to confirm the repair, as specified in paragraph (b)(11)(vi)(A) through (C) of this section.

(A) If Method 21 of appendix A-7 to this part is used to confirm the repair, maintain a record of the maximum instrument reading measured by Method 21 of appendix A-7 to this part.

(B) If OGI conducted in accordance with appendix K of this part is used to confirm the repair, maintain a record of video footage of the repair confirmation.

(C) If the leak is repaired by eliminating AVO indications of a leak, maintain a record of the specific sensory method used to confirm that the evidence of the leak is eliminated.

(v) For each repair delayed beyond 15 calendar days after detection of the leak, record:

(A) “Repair delayed” and the reason for the delay.

(B) The signature of the certifying official who made the decision that repair could not be completed without a process shutdown.

(C) The expected date of successful repair of the leak.

(D) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(12) A list of identification numbers for equipment that are designated for no detectable emissions complying with the provisions of § 60.5401b.

(13) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(14) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(15) A list of identification numbers for equipment that is in vacuum service.

(16) A list of identification numbers for equipment you designate as having the potential to emit methane or VOC less than 300 hr/yr.

(17) A list of identification numbers for valves where it was infeasible to replace leaking valves with low-e valves or repack existing valves with low-e packing technology, including the reasoning for why it was infeasible.

EDITORIAL NOTE

Editorial Note: At 89 FR 17125, Mar. 8, 2024, § 60.5421b was added with paragraph (b)(11)(vi) placed after paragraph (b)(11)(iii) and preceding paragraph (b)(11)(v).

§ 60.5422b What are my additional reporting requirements for process unit equipment affected facilities?

(a) You must submit semiannual reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in § 60.5420b(d). If the reporting form specific to this subpart is not available on the CEDRI website at the time that the report is due, submit the report to the Administrator at the appropriate address listed in § 60.4. Once the form has been available on the CEDRI website for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The date reporting forms 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 within 45 days after the end of the semiannual reporting period, regardless of the method in which the report is submitted.

(b) The initial semiannual report must include the following information:

(1) The general information specified in paragraph (c)(1) of this section.

(2) For each process unit:

(i) Process unit identification.

(ii) Number of valves subject to the monitoring requirements of §§ 60.5400b(b) and 60.5401b(f).

(iii) Number of pumps subject to the monitoring requirements of §§ 60.5400b(b) and 60.5401b(b).

(iv) Number of connectors subject to the monitoring requirements of §§ 60.5400b(b) and 60.5401b(h).

(v) Number of pressure relief devices subject to the monitoring requirements of §§ 60.5400b(b) and 60.5401b(c).

(vi) The information in paragraphs (c)(3) and (4) of this section.

(c) All subsequent semiannual reports must include the following information:

(1) The general information specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) The company name, facility site name, and address of the affected facility.

(ii) Beginning and ending dates of the reporting period.

(iii) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (c)(1)(iii).

(2) Process unit identification for each process unit.

(3) For each month during the semiannual reporting period for each process unit report:

(i) Number of valves for which leaks were detected as described in § 60.5400b(b) or § 60.5401b(f).

(ii) Number of valves for which leaks were not repaired as required in § 60.5400b(h) or § 60.5401b(i), the number of instances where it was technically infeasible to replace leaking valves with low-e valves or repack existing valves with low-e packing technology, including the reasoning for why it was technically infeasible.

(iii) Number of pumps for which leaks were detected as described § 60.5400b(b) or § 60.5401b(b).

(iv) Number of pumps for which leaks were not repaired as required in § 60.5400b(h) or § 60.5401b(i).

(v) Number of connectors for which leaks were detected as described in § 60.5400b(b) or § 60.5401b(h).

(vi) Number of connectors for which leaks were not repaired as required in § 60.5400b(h) or § 60.5401b(i).

(vii) Number of pressure relief devices for which leaks were detected as described in § 60.5400b(b) or § 60.5401b(c).

(viii) Number of pressure relief devices for which leaks were not repaired as required in § 60.5400b(h) or § 60.5401b(i).

(ix) Number of open-ended valves or lines for which leaks were detected as described in § 60.5400b(e) or § 60.5401b(d).

(x) Number of open-ended valves or lines for which leaks were not repaired as required in § 60.5400b(h) or § 60.5401b(i).

(xi) Number of pumps, valves, or connectors in heavy liquid service or pressure relief device in light liquid or heavy liquid service for which leaks were detected as described in § 60.5400b(g) or § 60.5401b(g).

(xii) Number of pumps, valves, or connectors in heavy liquid service or pressure relief device in light liquid or heavy liquid service for which leaks were not repaired as required in § 60.5400b(h) or § 60.5401b(i).

(xiii) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(4) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(5) Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

§ 60.5423b What are my additional recordkeeping and reporting requirements for sweetening unit affected facilities?

(a) You must retain records of the calculations and measurements required in §§ 60.5405b(a) and (b) and 60.5407b(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under § 60.7(f) of the General Provisions.

(b) In your initial annual report submitted in accordance with the procedures and schedule in § 60.5420b(b), include the information in paragraphs (b)(1) and (2) of this section.

(1) For each run of the initial performance test required by § 60.8(b):

(i) The average sulfur feed rate in Mg/D, determined according to § 60.5406b(b).

(ii) The average volumetric flow rate of acid gas from the sweetening unit, in dscm/day.

(iii) The H_2S concentration in the acid gas feed from the sweetening unit, percent by volume.

(iv) The emission rate of sulfur in kg/hr.

(v) The sulfur production rate in kg/hr.

(vi) The emission reduction efficiency achieved by the sulfur recovery technology, determined according to § 60.5406b(c).

(vii) The required initial SO_2 emission reduction efficiency, as determined from table 3 to this subpart based on the sulfur feed rate and the sulfur content of the acid gas of the affected facility.

(2) The required minimum SO_2 emission reduction efficiency you must achieve on a continuous basis, as determined from table 4 to this subpart based on the sulfur feed rate and the sulfur content of the acid gas of the affected facility.

(c) You must submit the performance test report in accordance with the requirements of § 60.5420b(b)(12).

(d) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. The procedures and schedule for submitting annual reports are located in § 60.5420b(b). For the purpose of these reports, excess emissions are defined as specified in paragraphs (d)(1) and (2) of this section. The report must contain the information specified in paragraph (d)(3) of this section.

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of § 60.5407b(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of § 60.5407b(b)(3). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(3) For each period of excess emissions during the reporting period, include the following information in your report:

(i) The date and time of commencement and completion of each period of excess emissions;

(ii) The required minimum efficiency (Z) and the actual average sulfur emissions reduction (R) for periods defined in paragraph (d)(1) of this section; and

(iii) The appropriate operating temperature and the actual average temperature of the gases leaving the combustion zone for periods defined in paragraph (d)(2) of this section.

(e) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less than 2 LT/D of H_2S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H_2S expressed as sulfur.

(f) If you elect to comply with § 60.5407b(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H_2S expressed as sulfur.

(g) The requirements of paragraph (d) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (d) of this section, provided they comply with the requirements established by the state. Electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph do not relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

§ 60.5424b What are my additional recordkeeping and reporting requirements if I comply with the alternative GHG and VOC standards for fugitive emissions components affected facilities and covers and closed vent systems?

This section provides notification, reporting, and recordkeeping requirements for owners and operators who choose to comply with an alternative GHG and VOC standard as specified in § 60.5398b for fugitive emissions components affected facilities and the alternative continuous inspection and monitoring requirements for covers and closed vent systems. You must submit an annual report in accordance with the schedule in § 60.5420b(b) which includes the information in paragraphs (a)(1), (b), and (d) of this section, as applicable. You must submit the notification in paragraph (a)(2) of this section and maintain the records in paragraphs (c) and (e) of this section, as applicable.

(a) ***Notifications.*** If you choose to comply with an alternative GHG and VOC standard as specified in § 60.5398b for fugitive emissions components affected facilities and the alternative continuous inspection and monitoring requirements for covers and closed vent systems, you must submit the notification in paragraph (a)(1) of this section. If you are required by § 60.5398b(c)(8) to develop a mass emission rate reduction plan, you must submit the notification in paragraph (a)(2) of this section.

(1) A notification to the Administrator of adoption of the alternative standards in the annual report required by § 60.5420b(b)(4) through (11).

(2) A notification, which includes the submittal of the mass emission rate reduction plan required by § 60.5398b(c)(8). You must submit the mass emission rate reduction plan to the Administrator within 60 days of the initial exceedance of the action level.

(b) ***Information submittal.*** If you comply with the periodic screening requirements of § 60.5398b(b), you must submit the information in paragraphs (b)(1) through (6) of this section in the annual report required by § 60.5420b(b)(4) through (11).

(1) Date of each periodic screening during the reporting period and date that results of the periodic screening were received.

(2) Alternative test method and technology used for each screening and the spatial resolution of the technology (*i.e.,* facility-level, area-level, or component-level).

(3) Any deviations from the monitoring plan developed under § 60.5398b(b)(2) or a statement that there were no deviations from the monitoring plan.

(4) Results from each periodic screening during the reporting period. If the results of the periodic screening indicate a confirmed detection of emissions from an affected facility, you must submit the information in paragraphs (b)(4)(i) through (iv) of this section.

(i) The date that the monitoring survey of your entire or the required portion of your fugitive emissions components affected facility was conducted.

(ii) The date that you completed the instrument inspections of all required covers and closed vent systems(s).

(iii) The date that you conducted the visual inspection for emissions of all required covers and closed vent systems.

(iv) For each fugitive emission from a fugitive emissions components affected facility and all emissions or defects of each cover and closed vent system, you must submit the information in paragraphs (b)(4)(iv)(A) through (D) of this section.

(A) Number and type of components for which fugitive emissions were detected.

(B) Each emission or defect identified during the inspection for each cover and closed vent system.

(C) Date of repair for each fugitive emission from a fugitive emissions components affected facility or each emission or defect for each cover and closed vent system.

(D) Number and type of fugitive emission components and identification of each cover or closed vent system placed on delay of repair and an explanation for each delay of repair.

(5) The information in paragraphs (b)(5)(i) through (iv) of this section if you are required to conduct OGI survey
60.5398b(b)(1)(i) or if you replace a periodic screening event with an OGI survey in accordance with § 60.5

(i) The date of the OGI survey.

(ii) Number and type of components for which fugitive emissions were detected.

(iii) Number and type of fugitive emissions components that were not repaired as required in § 60.5397b(

(iv) Number and type of fugitive emission components placed on delay of repair and an explanation for ea

(6) Any additional information regarding the performance of the periodic screening technology as specified by
part of the alternative test method approval described in § 60.5398b(d).

(c) ***Maintain records.*** If you comply with the periodic screening requirements of § 60.5398b(b), you must maintain th
(c)(1) through (11) of this section in addition to the records as specified in § 60.5420b(c)(3) through (9) and (c)(

(1) The monitoring plan as required in § 60.5398b(b)(2).

(2) Date of each periodic screening and date that results of the periodic screening were received.

(3) Name of screening operator.

(4) Alternative test method and technology used for screening, as well as the aggregate detection threshold fo
spatial resolution of the technology (*i.e.,* facility-level, area-level, or component-level).

(5) Records of calibrations for technology used during the screening if calibration is required by the alternative
accordance with § 60.5398b(d).

(6) Results from periodic screening. If the results of the periodic screening indicate a confirmed detection of e
affected facility, you must maintain the records in paragraphs (c)(6)(i) through (v) of this section.

(i) The date of the inspection of the fugitive emissions components and inspection of covers and closed
specified in § 60.5398b(b)(5).

(ii) Name of operator(s) performing the survey or inspection.

(iii) For surveys and instrument inspections, identification of the monitoring instrument(s) used.

(iv) Records of calibrations for the instrument(s) used during the survey or instrument inspection, as appl

(v) For each fugitive emission from a fugitive emissions components affected facility and each leak or de
closed vent system inspection, you must maintain the records in paragraphs (c)(6)(v)(A) through (F) o

(A) The location of the fugitive emissions identified using a unique identifier for the source of the em
fugitive emissions component.

(B) The location of the emission or defect from a cover or closed vent system using a unique identifi
emission or defect.

(C) If a defect of a closed vent system, cover, or control device is identified, a description of the defe

(D) The date of repair for each fugitive emission from a fugitive emissions components affected fac
defect for each cover and closed vent system.

(E) Number and type of fugitive emission components and identification of each cover or closed ver
of repair and an explanation for each delay of repair.

(F) For each fugitive emission component placed on delay of repair for reason of replacement comp
operator must document: the date the component was added to the delay of repair list, the date
component or part thereof was ordered, the anticipated component delivery date (including any

(iii) Type of fugitive emissions component for which fugitive emissions were detected.

(iv) The date of first attempt at repair of the fugitive emissions component(s).

(v) The date of successful repair of the fugitive emissions component(s), including the resurvey to verify

(vi) Identification of each fugitive emissions component placed on delay of repair and an explanation for e

(vii) For each fugitive emission component placed on delay of repair for reason of replacement componen operator must document: the date the component was added to the delay of repair list, the date the re component or part thereof was ordered, the anticipated component delivery date (including any estim date provided by the vendor), and the actual arrival date of the component.

(10) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring

(11) All records required by the alternative approved in accordance with § 60.5398b(d).

(d) ***Information submittal.*** If you comply with the continuous monitoring system requirements of § 60.5398b(c), you information in paragraphs (d)(1) through (6) of this section in the annual report required by § 60.5420b(b)(4) thr

(1) The start date and end date for each period where the emissions rate determined in accordance with § 60. one of the action levels determined in accordance with § 60.5398b(c)(4). Include which action level was ex day rolling average), the numerical value of the action level, and the mass emission rate calculated by the c system in the report.

(2) The date the investigative analysis was initiated, and the result of the investigative analysis conducted in ac 60.5398b(c)(7), as applicable.

(3) Dates of implementation and completion of action(s) taken to reduce the mass emission rate and a descrip taken in accordance with § 60.5398b(c)(7), as applicable.

(4) If there are no instances reported under paragraph (d)(1) of this section, report your numerical action levels rolling average and highest 90-day rolling average determined by your continuous monitoring system durin

(5) The start date for each instance where the 12-month rolling average operational downtime of the system e the value of the 12-month rolling average operational downtime during the period. If there were no instance period where the 12-month rolling average operational downtime of the system exceeded 10 percent, repor 12-month rolling average operational downtime during the reporting period.

(6) Any additional information regarding the performance of the continuous monitoring system as specified by part of the alternative test method approval described in § 60.5398b(d).

(e) ***Maintain records.*** If you comply with the continuous monitoring system requirements of § 60.5398b(c), you mus paragraphs (e)(1) through (15) of this section.

(1) The monitoring plan required by § 60.5398b(c)(2).

(2) Date of commencement of continuous monitoring with your continuous monitoring system.

(3) The detection threshold of the continuous monitoring system.

(4) The results of checks for power and function in accordance with § 60.5398b(c)(1)(ii).

(5) The beginning and end of each period of operational downtime for the system.

(6) Each rolling 12-month average operational downtime for the system, calculated in accordance with § 60.53

(7) The 7-day rolling average and 90-day rolling average action levels for the site determined in accordance wit

(8) The information in paragraphs (e)(8)(i) through (v) of this section each time you establish site-specific bas accordance with § 60.5398b(c)(5).

(10) Each daily, 7-day, and 90-day average mass emission rate which was determined in accordance with § 60.5398b(c)(6). If you exceed the 90-day action level, you must also keep records of the 30-day average mass emission rate following completion of the initial actions to reduce the average mass emission rate, in accordance with § 60.5398b(c)(8)(i).

(11) The results of each comparison of the emissions rate determined in accordance with § 60.5398b(c)(6) to the action level determined in accordance with § 60.5398b(c)(4).

(12) The date the investigative analysis was initiated, and the result of the investigative analysis conducted in accordance with § 60.5398b(c)(7), as applicable.

(13) Dates of implementation and completion of action(s) taken to reduce the mass emission rate below the action level and a description of the action(s) taken in accordance with § 60.5398b(c)(7), as applicable.

(14) Each mass emission rate reduction plan developed in accordance with § 60.5398b(c)(8), as applicable. You must keep records of the actions taken in accordance with the plan and the date such actions are taken.

(15) Any additional information regarding the performance of the continuous monitoring technology as specified by the Administrator, as part of the alternative test method approval described in § 60.5398b(d).

§ 60.5425b What parts of the General Provisions apply to me?

Table 5 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

§ 60.5430b What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act or in subpart A of this part; and the following terms shall have the specific meanings given them.

Access to electrical power means commercial line power is available onsite, with sufficient capacity to support the required power loading of onsite equipment, and which provides reliable and consistent power.

Acid gas means a gas stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Artificial lift equipment means mechanical pumps including, but not limited to, rod pumps and electric submersible pumps used to flowback fluids from a well.

Associated gas means the natural gas from wells operated primarily for oil production that is released from the liquid hydrocarbon during the initial stage of separation after the wellhead. Associated gas production begins at the startup of production after the flow back period ends. Gas from wildcat or delineation wells is not associated gas.

Average aggregate detection threshold means:

(1) For the purposes of § 60.5398b, the average of all site-level detection thresholds from a single deployment (*e.g.,* a singular flight that surveys multiple well sites, centralized production facility, and/or compressor stations) of a technology; and

(2) For the purposes of § 60.5371b, the average of all site-level detection thresholds from a single deployment in the same basin and field.

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a process controller.

Capital expenditure means, as an alternative to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(1) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: P = R × A, where:

(i) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation: A = Y × (B ÷ 100);

(ii) The percent Y is determined from the following equation: Y = (CPI of date of construction/most recently available CPI of date of project), where the “CPI-U, U.S. city average, all items” must be used for each CPI value; and

(iii) The applicable basic annual asset guideline repair allowance, B, is 4.5.

(2) [Reserved]

Centralized production facility means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations.

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

Centrifugal compressor equipped with sour seal oil separator and capture system means a wet seal centrifugal compressor system which has an intermediate closed process that degasses most of the gas entrained in the sour seal oil and sends that gas to either another process or combustion device (*i.e.,* degassed emissions are recovered). The de-gas emissions are routed back to a process or combustion device directly from the intermediate closed degassing process; after the intermediate closed process the oil is ultimately recycled for recirculation in the seals to the lube oil tank where any small amount of residual gas is released through a vent.

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities with an affected facility subject to this subpart and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including but not limited to general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, state, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the CAA or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under this part.

Closed vent system means a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back to a process.

Coil tubing cleanout means the process where an operator runs a string of coil tubing to the packed proppant within a well and jets the well to dislodge the proppant and provide sufficient lift energy to flow it to the surface. Coil tubing cleanout includes mechanical methods to remove solids and/or debris from a wellbore.

Collection system means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Compressor mode means the operational and pressurized status of a compressor. For both centrifugal compressors and reciprocating compressors, “mode” refers to either: Operating-mode, standby-pressurized-mode, or not-operating-depressurized-mode.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes but is not limited to gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, centralized production facility, or an onshore natural gas processing plant, is not a compressor station for purposes of § 60.5365b(e) and § 60.5397b.

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

Connector means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.

Continuous bleed means a continuous flow of pneumatic supply natural gas to a process controller.

Crude oil and natural gas source category means:

(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and

(2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.

Custody meter means the meter where natural gas or hydrocarbon liquids are measured for sales, transfers, and/or royalty determination.

Custody meter assembly means an assembly of fugitive emissions components, including the custody meter, valves, flanges, and connectors necessary for the proper operation of the custody meter.

Custody transfer means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or adsorption column (absorber).

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

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

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(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 limit, operating limit, or work practice standard of this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Distance piece means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.

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 screw or crimping. Hard-piping is not ductwork.

Emergency shutdown device means a device which functions exclusively to protect personnel and/or prevent physical damage to equipment by shutting down equipment or gas flow during unsafe conditions resulting from an unexpected event, such as a pipe break or fire. For the purposes of this subpart, an emergency shutdown device is not used for routine control of operating conditions.

Equipment, as used in the standards and requirements of this subpart relative to the process unit equipment affected facility at onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that has the potential to emit methane or VOC and any device or system required by those same standards and requirements of this subpart.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

First attempt at repair means an action taken for the purpose of stopping or reducing fugitive emissions to the atmosphere. First attempts at repair include, but are not limited to, the following practices where practicable and appropriate: Tightening bonnet bolts; replacing bonnet bolts; tightening packing gland nuts; or injecting lubricant into lubricated packing.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Flowback means the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage. Screenouts, coil tubing cleanouts, and plug drill-outs are not considered part of the flowback process.

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-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

Fugitive emissions means, for the purposes of § 60.5397b, any indication of emissions observed from a fugitive emissions component using AVO, an indication of visible emissions observed from an OGI instrument, or an instrument reading of 500 ppmv or greater using Method 21 of appendix A-7 to this part.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, such as valves (including separator dump valves), connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to § 60.5411b, thief hatches or other openings on a storage vessel not subject to § 60.5395b, compressors, instruments, meters, and yard piping.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Hard-piping means pipe or tubing that is manufactured and properly installed using good engineering judgment and standards such as ASME B31.3, Process Piping (available from the American Society of Mechanical Engineers, P.O. Box 2300, Fairfield, NJ 07007-2300).

Hydraulic fracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

In gas/vapor service means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.

In heavy liquid service means that the piece of equipment is not in gas/vapor service or in light liquid service.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.5402b(d)(2) or § 60.5403b.

In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa) (0.7 psia) below ambient pressure.

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Initial calibration value as used in the standards and requirements of this subpart relative to the process unit equipment affected facility at onshore natural gas processing plants means the concentration measured during the initial calibration at the beginning of each day required in § 60.5403b, or the most recent calibration if the instrument is recalibrated during the day (*i.e.,* the calibration is adjusted) after a calibration drift assessment.

Initial flowback stage means the period during a well completion operation which begins at the onset of flowback and ends at the separation flowback stage.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Intermittent vent natural gas-driven process controller means a process controller that is not designed to have a continuous bleed rate but is instead designed to only release natural gas to the atmosphere as part of the actuation cycle.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Liquid collection system means tankage and/or lines at a well site to contain liquids from one or more wells or to convey liquids to another site.

Liquids dripping means any visible leakage from the seal, including spraying, misting, clouding, and ice formation.

Liquids unloading means the unloading of liquids that have accumulated over time in gas wells, which are impeding or halting production. Routine well maintenance activities, including workovers, screenouts, coil tubing cleanouts, or any other activity that requires a rig or other machinery are not considered liquids unloading.

Local distribution company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

Low-e valve means a valve (including its specific packing assembly) for which the manufacturer has issued a written warranty or performance guarantee that it will not emit fugitives at greater than 100 ppm in the first five years. A valve may qualify as a low-e valve if it is as an extension of another valve that has qualified as a low-e valve.

Low-e packing means a valve packing product for which the manufacturer has issued a written warranty or performance guarantee that it will not emit fugitives at greater than 100 ppm in the first five years. Low-e injectable packing is a type of low-e packing product for which the manufacturer has also issued a written warranty or performance guarantee and that can be injected into a valve during a "drill-and-tap" repair of the valve.

Low pressure well means a well that satisfies at least one of the following conditions:

(1) The static pressure at the wellhead following fracturing but prior to the onset of flowback is less than the flow line pressure;

(2) The pressure of flowback fluid immediately before it enters the flow line, as determined under § 60.5432b, is less than the flow line pressure; or

(3) Flowback of the fracture fluids will not occur without the use of artificial lift equipment.

Major production and processing equipment means reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, control devices, natural gas-driven process controllers, natural gas-driven pumps, and storage vessels or tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water, for the purpose of determining whether a well site is a wellhead only well site.

Maximum average daily throughput means the following:

(1) The earliest calculation of daily average throughput, determined as described in paragraph (2) or (3) of this definition, to a tank battery over the days that production is routed to that tank battery during the 30-day PTE evaluation period employing generally accepted methods specified in § 60.5365b(e)(2).

(2) If throughput to the tank battery is measured on a daily basis (*e.g.,* via level gauge automation or daily manual gauging), the maximum average daily throughput is the average of all daily throughputs for days on which throughput was routed to the tank battery during the 30-day evaluation period; or

(3) If throughput to the tank battery is not measured on a daily basis (*e.g.,* via manual gauging at the start and end of loadouts), the maximum average daily throughput is the highest, of the average daily throughputs, determined for any production period to that tank battery during the 30-day evaluation period, as determined by averaging total throughput to that tank battery over each production period. A production period begins when production begins to be routed to a tank battery and ends either when throughput is routed away from that tank battery or when a loadout occurs from that tank battery, whichever happens first. Regardless of the determination methodology, operators must not include days during which throughput is not routed to the tank battery when calculating maximum average daily throughput for that tank battery.

Multi-wellhead only well site means a well site that contains two or more wellheads and no major production and processing equipment.

Natural gas-driven diaphragm pump means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of this subpart. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

Natural gas-driven piston pump means a positive displacement pump powered by pressurized natural gas that moves and pressurizes fluid by using one or more reciprocating pistons. A pump in which a fluid is displaced by a piston driven by a diaphragm is considered a piston pump for purposes of this subpart. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a piston pump.

Natural gas-driven process controller means a process controller powered by pressurized natural gas.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long-distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

No detectable emissions means, for the purposes of § 60.5401b and § 60.5403b, that the equipment is operating with an instrument reading of less than 500 ppmv above background, as determined by Method 21 of appendix A-7 to this part.

No identifiable emissions means, for the purposes of covers, closed vent systems, and self-contained natural gas-driven process controllers and as determined according to the provisions of § 60.5416b, that no emissions are detected by AVO means when inspections are conducted by AVO; no emissions are imaged with an OGI camera when inspections are conducted with OGI; and equipment is operating with an instrument reading of less than 500 ppmv above background, as determined by Method 21 of appendix A-7 to this part when inspections are conducted with Method 21.

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non-natural gas-driven process controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Open-ended valve or line or open-ended vent line means any valves, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

Plug drill-out means the removal of a plug (or plugs) that was used to isolate different sections of the well.

Process controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Pressure release means the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

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.

Pressurized mode means when the compressor contains natural gas that is maintained at a pressure higher than the atmospheric pressure.

Process improvement means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. The following are not considered process unit shutdowns:

(1) 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.

(2) 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.

(3) The use of spare equipment and technically feasible bypassing of equipment without stopping production.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Qualified Professional Engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge, and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Quarter means a 3-month period. For purposes of standards for process unit equipment affected facilities at onshore natural gas processing plants, the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere, or other mechanism that provides the same function.

Recovered gas means gas recovered through the separation process during flowback.

Recovered liquids means any crude oil, condensate or produced water recovered through the separation process during flowback.

Reduced emissions completion means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2).

Removed from service means that a storage vessel affected facility has been physically isolated and disconnected from the process for a purpose other than maintenance in accordance with § 60.5395b(c)(1).

Repaired means the following:

(1) For the purposes of fugitive emissions components affected facilities, that fugitive emissions components are adjusted, replaced, or otherwise altered, in order to eliminate fugitive emissions and resurveyed as specified in § 60.5397b(h)(4) and it is verified that emissions from the fugitive emissions components are below the applicable fugitive emissions definition.

(2) For the purposes of process unit equipment affected facilities, that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in §§ 60.5400b and 60.5401b and is re-monitored as specified in § 60.5400b(b) introductory text and (b)(1) or § 60.5403b, respectively, to verify that emissions from the equipment are below the applicable leak definition. Pumps in light liquid service subject to § 60.5400b(c)(2) or § 60.5401b(b)(1)(ii) are not subject to re-monitoring.

Replacement cost means the capital needed to purchase all the depreciable components in a facility.

Returned to service means that a storage vessel affected facility that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel affected facility; or

(2) Installed in any location covered by this subpart and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly 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 regulated materials and/or incorporated into a product; and/or recovered.

Salable quality gas means natural gas that meets the flow line or collection system operator specifications, regardless of whether such gas is sold.

Screenout means an attempt to clear proppant from the wellbore to dislodge the proppant out of the well.

Self-contained process controller means a natural gas-driven process controller that releases gas into the downstream piping and not to the atmosphere, resulting in zero methane and VOC emissions.

Self-contained wet seal centrifugal compressor means:

(1) A wet seal centrifugal compressor system that is a closed process that ports the degassing emissions into the natural gas line at the compressor suction (*i.e.,* degassed emissions are recovered) or which has an intermediate closed process that degasses most of the gas entrained in the seal oil and sends that gas to another process. The de-gas emissions are routed back to suction or process directly from the closed or intermediate closed degassing process; after the closed or intermediate closed degassing process the oil is ultimately recycled for recirculation in the seals to the lube oil tank where any small amount of residual gas is released through a vent.

(2) A wet seal centrifugal compressor equipped with mechanical wet seals, where

(i) A differential pressure is maintained on the system and there is no off gassing of the lube oil, and

(ii) The mechanical seal is integrated into the compressor housing.

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.

Separation flowback stage means the period during a well completion operation when it is technically feasible for a separator to function. The separation flowback stage ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.

Separator dump valve means, for purposes of the fugitive emission standards in §§ 60.5397b and 60.5398b, a liquid-control valve in a separator that controls the liquid level within the separator vessel.

Single wellhead only well site means a wellhead only well site that contains only one wellhead and no major production and processing equipment.

Small well site means, for purposes of the fugitive emissions standards in §§ 60.5397b and 60.5398b, a well site that contains a single wellhead, no more than one piece of certain major production and processing equipment, and associated meters and yard piping. Small well sites cannot include any controlled storage vessels (or controlled tank batteries), control devices, natural gas-driven process controllers, or natural gas-driven pumps.

Startup of production means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water, except as otherwise provided in this definition. For the purposes of the fugitive monitoring requirements of § 60.5397b, *startup of production* means the beginning of the continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of § 60.5395b(c)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by § 60.5420b(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

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

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Tank battery means a group of all storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel if only one storage vessel is present.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A-6 to this part.

Total SO_2 equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO_2 to the quantity of SO_2 that would be obtained if all reduced sulfur compounds were converted to SO_2 (ppmv or kg/dscm (lb/dscf)).

UIC Class I oilfield disposal well means a well with a UIC Class I permit that meets the definition in 40 CFR 144.6(a)(2) and receives eligible fluids from oil and natural gas exploration and production operations.

UIC Class II oilfield disposal well means a well with a UIC Class II permit where wastewater resulting from oil and natural gas production operations is injected into underground porous rock formations not productive of oil or gas, and sealed above and below by unbroken, impermeable strata.

Underground storage vessel means a storage vessel stored below ground.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well completion means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a well completion affected facility.

Well completion vessel means a vessel that contains flowback during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a tank or other vessel that is skid-mounted or portable. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart.

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For the purposes of the fugitive emissions standards at § 60.5397b, a well site does not include:

(1) UIC Class II oilfield disposal wells and disposal facilities;

(2) UIC Class I oilfield disposal wells; and

(3) The flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Wellhead only well site means, for the purposes of the fugitive emissions standards at § 60.5397b and the standards in § 60.5398b, a well site that contains one or more wellheads and no major production and processing equipment.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

Yard piping means hard-piping at a well site, centralized production facility, or compressor station that is not part of a closed vent system.

§ 60.5432b How do I determine whether a well is a low pressure well using the low pressure well equation?

(a) To determine that your well is a low pressure well subject to § 60.5375b(f), you must determine whether the characteristics of the well are such that the well meets the definition of low pressure well in § 60.5430b. To determine that the well meets the definition of low pressure well in § 60.5430b, you must use the low pressure well equation:

Equation 1 to paragraph (a)

$$P_L\,(psia) = 0.495 \times P_R - \frac{q_g}{q_g+q_o+q_w}[0.05 \times P_R + 0.038 \times L - 67.578] - \left[\frac{q_o}{q_g+q_o+q_w} \times \frac{\rho_o}{144} + \frac{q_w}{q_g+q_o+q_w} 0.433\right] \cdot L$$

Where:

(1) P_L is the pressure of flowback fluid immediately before it enters the flow line, expressed in pounds force per square inch (psia), and is to be calculated using the equation above;

(2) P_R is the pressure of the reservoir containing oil, gas, and water at the well site, expressed in psia;

(3) L is the true vertical depth of the well, expressed in feet (ft);

(4) q_o is the flow rate of oil in the well, expressed in cubic feet/second (cu ft/sec);

(5) q_g is the flow rate of gas in the well, expressed in cu ft/sec;

(6) q_w is the flow rate of water in the well, expressed in cu ft/sec;

(7) ρ_o is the density of oil in the well, expressed in pounds mass per cubic feet (lbm/cu ft).

(b) You must determine the four values in paragraphs (a)(4) through (7) of this section, using the calculations in paragraphs (b)(1) through (15) of this section.

(1) Determine the value of the bottom hole pressure, P_{BH} (*psia*), based on available information at the well site, or by calculating it using the reservoir pressure, P_R (*psia*), in the following equation:

Equation 2 to paragraph (b)(1)

$$P_{BH}\,(psia) = \frac{1}{2} P_R$$

(2) Determine the value of the bottom hole temperature, T_{BH} (*F*), based on available information at the well site, or by calculating it using the true vertical depth of the well, *L (ft)*, in the following equation:

Equation 3 paragraph (b)(2)

$$T_{BH}\,(F) = (0.014 \times L) + 79.081$$

(3) Calculate the value of the applicable natural gas specific gravity that would result from a separator pressure of 100 psig, γ_{gs}, using the following equation with: Separator at standard conditions (pressure, p = 14.7 (*psia*), temperature, T = 60 (*F*)); the oil API gravity at the well site, γ_0; and the gas specific gravity at the separator under standard conditions, γ_{gp} = 0.75:

Equation 4 to paragraph (bh)(3)

$$\gamma_{gs} = \gamma_{gp} \cdot \left(1.0 + 5.912\,x\,10^{-5} \cdot \gamma_o \cdot T \cdot log\left(\frac{p}{114.7}\right)\right)$$

(4) Calculate the value of the applicable dissolved GOR, *Rs (scf/STBO)*, using the following equation with: The bottom hole pressure, P_{BH} (*psia*), determined in (b)(1) of this section; the bottom hole temperature, T_{BH} (*F*), determined in (b)(2) of this section; the gas gravity at separator pressure of 100 psig, γ_{gs}, calculated in (b)(3) of this section; the oil API gravity, γ_o, at the well site; and the constants, C1, C2, and C3, found in Table 1 to this paragraph(b)(4):

Equation 5 to paragraph (b)(4)

$$R_s\left(\frac{scf}{STBO}\right) = C1 \cdot \gamma_{gs} \cdot {P_{BH}}^{C2} \cdot exp\left[C3\left(\frac{\gamma_o}{T_{BH} + 460}\right)\right]$$

Table 1 to Paragraph (b)(4)—Coefficients for the Correlation for R_s

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	0.0362	0.0178
C2	1.0937	1.1870
C3	25.7240	23.931

(5) Calculate the value of the oil formation volume factor, *Bo (bbl/STBO),* using the following equation with: The bottom hole temperature, T_{BH} (*F*), determined in paragraph (b)(2) of this section; the gas gravity at separator pressure of 100 psig, γ_{gs}, calculated in paragraph (b)(3) of this section; the dissolved GOR, Rs (scf/STBO), calculated in paragraph (b)(4) of this section; the oil API gravity, γ*o,* at the well site; and the constants, C1, C2, and C3, found in Table 2 to this paragraph (b)(5):

Equation 6 to paragraph (b)(5)

$$B_o\left(\frac{bbl}{STBO}\right) = 1.0 + C1 \cdot R_s + (T_{BH} - 60)\left(\frac{\gamma_o}{\gamma_{gs}}\right) \cdot (C2 + C3 \cdot R_s)$$

Table 2 to Paragraph (b)(5)—Coefficients for the Correlation for B_o

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	4.677×10^{-4}	4.670×10^{-4}
C2	1.751×10^{-5}	1.100×10^{-5}
C3	-1.811×10^{-8}	1.337×10^{-9}

(6) Calculate the density of oil at the wellhead,

$$\rho_{WH}\left(\frac{lbm}{cu\,ft}\right),$$

using the following equation with the value of the oil API gravity, γ*o,* at the well site:

Equation 7 to paragraph (b)(6)

$$\rho_{WH}\left(\frac{lbm}{cu\,ft}\right) = \frac{141.5}{\gamma_o + 131.5} \times 62.4$$

(7) Calculate the density of oil at bottom hole conditions,

$$\rho_{BH}\left(\frac{lbm}{cu\,ft}\right),$$

using the following equation with: the dissolved GOR, Rs (scf/STBO), calculated in paragraph (b)(4) of this section; the oil formation volume factor, Bo (bbl/STBO), calculated in paragraph (b)(5) of this section; the oil density at the wellhead,

$$\rho_{WH}\left(\frac{lbm}{cu\,ft}\right),$$

calculated in paragraph (b)(6) of this section; and the dissolved gas gravity, γ_{gd} = 0.77:

Equation 8 to paragraph (b)(7)

$$\rho_{BH}\left(\frac{lbm}{cu\,ft}\right) = \frac{\rho_{WH} + 0.0136 \times Rs \times \gamma_{gd}}{Bo}$$

(8) Calculate the density of oil in the well,

$$\rho_o\left(\frac{lbm}{cu\,ft}\right),$$

using the following equation with the density of oil at the wellhead,

$$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right),$$

calculated in paragraph (b)(6) of this section; and the density of oil at bottom hole conditions,

$$\rho_{BH}\left(\frac{lbm}{cu\ ft}\right),$$

calculated in paragraph (b)(7) of this section:

Equation 9 to paragraph (b)(8)

$$\rho_o\left(\frac{lbm}{cu\ ft}\right) = 0.5 \times (\rho_{WH} + \rho_{BH})$$

(9) Calculate the oil flow rate, q_o (*cu ft/sec,*) using the following equation with: the oil formation volume factor, *Bo* (bbl/STBO), as calculated in paragraph (b)(5) of this section; and the estimated oil production rate at the well head, *Qo* (STBO/day):

Equation 10 to paragraph (b)(9)

$$q_o\left(\frac{cu\ ft}{sec}\right) = \mathrm{Qo}\left(\frac{\mathrm{STBO}}{\mathrm{day}}\right) \times \mathrm{Bo}\left(\frac{\mathrm{bbl}}{\mathrm{STBO}}\right) \times 5.614\left(\frac{\mathrm{cu\ ft}}{\mathrm{bbl}}\right) \times \frac{1}{24 \times 60 \times 60}\left(\frac{day}{sec}\right)$$

(10) Calculate the critical pressure, P_c (psia), and critical temperature, T_c (R), using the equations below with: Gas gravity at standard conditions (pressure, P = 14.7 (*psia*), temperature, T = 60 (*F*)), γ = 0.75; and where the mole fractions of nitrogen, carbon dioxide and hydrogen sulfide in the gas are X_{N2} = 0.168225, X_{CO2} = 0.013163, and X_{H2S} = 0.013680, respectively:

P_c (*psia*) = $678 - 50 \cdot (\gamma_g - 0.5) - 206.7 \cdot X_{N2} + 440 \cdot X_{CO2} + 606.7 \cdot X_{H2S}$

T_c (*R*) = $326 + 315.7 \cdot (\gamma_g - 0.5) - 240 \cdot X_{N2} - 88.3 \cdot X_{CO2} + 133.3 \cdot X_{H2S}$

(11) Calculate reduced pressure, P_r, and reduced temperature, T_r, using the following equations with: the bottom hole pressure, P_{BH}, as determined in paragraph (b)(1) of this section; the bottom hole temperature, T_{BH} (*F*), as determined in paragraph (b)(2) of this section in the following equations:

Equation 11 to paragraph (b)(11)

$$P_r = \frac{P_{BH}}{P_c}$$

$$T_r = \frac{T_{BH} + 460}{T_c}$$

(12)

(i) Calculate the gas compressibility factor, *Z*, using the following equation with the reduced pressure, P_r, calculated in paragraph (b)(11) of this section:

Equation 12 to paragraph (b)(12)(i)

$$z = A + \frac{(1 - A)}{e^B} + C \cdot p_r^D$$

(ii) The values for A, B, C, D in the above equation, are calculated using the following equations with the reduced pressure, P_r, and reduced temperature, T_r, calculated in paragraph (b)(11) of this section:

Equation 13 to paragraph (b)(12)(ii)

$$A = 1.39 \cdot (T_r - 0.92)^{0.5} - 0.36 * T_r - 0.101$$

$$B = (0.62 - 0.23 \cdot T_r) \cdot P_r + \left(\frac{0.066}{(T_r - 0.86)} - 0.037\right) \cdot P_r^2 + \frac{0.32}{10^{9(T_r-1)}} \cdot P_r^6$$

$$C = (0.132 - 0.32 \cdot \log(T_r))$$

$$D = 10^{0.3106-0.49 T_r + 0.1824 T_r^2}$$

(13) Calculate the gas formation volume factor,

$$B_g\left(\frac{cuft}{scf}\right),$$

using the bottom hole pressure, P_{BH}*(psia),* as determined in paragraph (b)(1) of this section; and the bottom hole temperature, T_{BH}(*F*), as determined in paragraph (b)(2) of this section:

Equation 14 to paragraph (b)(13)

$$B_g\left(\frac{cuft}{scf}\right) = 0.0283 \cdot \frac{Z \cdot (T_{BH} + 460)}{P_{BH}} ()$$

(14) Calculate the gas flow rate,

$$q_g\left(\frac{cu\,ft}{sec}\right),$$

using the following equation with: the value of gas formation volume factor,

$$B_g\left(\frac{cuft}{scf}\right),$$

calculated in paragraph (b)(13) of this section; the estimated gas production rate, Qg (scf/day); the estimated oil production rate, Qo (STBO/day); and the dissolved GOR, Rs (scf/STBO), as calculated in paragraph (b)(4) of this section:

Equation 15 to paragraph (b)(14)

$$q_g\left(\frac{cf}{sec}\right) = (Q_g - R_s \cdot Q_o) \cdot B_g \cdot \frac{1}{24x60x60}$$

(15) Calculate the flow rate of water in the well, q_w (*cu ft/sec*), using the following equation with the water production rate Qw (bbl/day) at the well site:

Equation 16 to paragraph (b)(15)

$$q_w\left(\frac{cf}{sec}\right) = \mathrm{Qw}\left(\frac{\mathrm{bbl}}{\mathrm{day}}\right) \times 5.614\left(\frac{\mathrm{cf}}{\mathrm{bbl}}\right) \times \frac{1}{24 \times 60 \times 60}\left(\frac{day}{sec}\right)$$

§§ 60.5433b-60.5439b [Reserved]

Table 1 to Subpart OOOOb of Part 60—Alternative Technology Periodic Screening Frequency at Well Sites, Centralized Production Facilities, and Compressor Stations Subject to AVO Inspections With Quarterly OGI or EPA Method 21 Monitoring

Minimum screening frequency	Minimum detection threshold of screening technology * (kg/hr)
Quarterly	≤1
Bimonthly	≤2
Bimonthly + Annual OGI	≤10
Monthly	≤5
Monthly + Annual OGI	≤15

* Based on a probability of detection of 90%.

Table 2 to Subpart OOOOb of Part 60—Alternative Technology Periodic Screening Frequency at Well Sites and Centralized Production Facilities Subject to AVO Inspections and/or Semiannual OGI or EPA Method 21 Monitoring

Minimum screening frequency	Minimum detection threshold of screening technology * (kg/hr)
Semiannual	≤1
Triannual	≤2
Triannual + Annual OGI	≤10
Quarterly	≤5
Quarterly + Annual OGI	≤15
Bimonthly	≤15

* Based on a probability of detection of 90%

Table 3 to Subpart OOOOb of Part 60—Required Minimum Initial SO_2 Emission Reduction Efficiency (Z_i)

<table>
<tr><th rowspan="2">H_2S content of acid gas (Y), %</th><th colspan="4">Sulfur feed rate (X), LT/D</th></tr>
<tr><th>2.0 < X < 5.0</th><th>5.0 < X < 15.0</th><th>15.0 < X < 300.0</th><th>X > 300.0</th></tr>
<tr><td>Y > 50</td><td>79.0</td><td colspan="3">$88.51X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller.</td></tr>
<tr><td>20 < Y < 50</td><td>79.0</td><td colspan="2">$88.51X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller</td><td>97.9</td></tr>
<tr><td>10 < Y < 20</td><td>79.0</td><td>$88.51X^{0.0101}Y^{0.0125}$ or 93.5, whichever is smaller</td><td>93.5</td><td>93.5</td></tr>
<tr><td>Y < 10</td><td>79.0</td><td>79.0</td><td>79.0</td><td>79.0</td></tr>
</table>

Table 4 to Subpart OOOOb of Part 60—Required Minimum SO_2 Emission Reduction Efficiency (Z_c)

<table>
<tr><th rowspan="2">H_2S content of acid gas (Y), %</th><th colspan="4">Sulfur feed rate (X), LT/D</th></tr>
<tr><th>$2.0 < X < 5.0$</th><th>$5.0 < X < 15.0$</th><th>$15.0 < X < 300.0$</th><th>$X > 300.0$</th></tr>
<tr><td>$Y > 50$</td><td>74.0</td><td colspan="3">$85.35X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller.</td></tr>
<tr><td>$20 < Y < 50$</td><td>74.0</td><td colspan="2">$85.35X^{0.0144}Y^{0.0128}$ or 97.5, whichever is smaller</td><td>97.5</td></tr>
<tr><td>$10 < Y < 20$</td><td>74.0</td><td>$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller</td><td>90.8</td><td>90.8</td></tr>
<tr><td>$Y < 10$</td><td>74.0</td><td>74.0</td><td>74.0</td><td>74.0</td></tr>
</table>

Displaying title 40, up to date as of 5/07/2024. Title 40 was last amended 5/07/2024.

There have been changes in the last two weeks to Subpart OOOOa.

Title 40 —Protection of Environment
Chapter I —Environmental Protection Agency
Subchapter C —Air Programs
Part 60 —Standards of Performance for New Stationary Sources

ENHANCED CONTENT - TABLE OF CONTENTS

Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After September 18, 2015 and On or Before December 6, 2022

Source: 81 FR 35898, June 3, 2016, unless otherwise noted.

§ 60.5360a What is the purpose of this subpart?

(a) ***Scope.*** This subpart establishes emission standards and compliance schedules for the control of the pollutant greenhouse gases (GHG). The greenhouse gas standard in this subpart is in the form of a limitation on emissions of methane from affected facilities in the crude oil and natural gas source category that commence construction, modification, or reconstruction after September 18, 2015. This subpart also establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities in the crude oil and natural gas source category that commence construction, modification, or reconstruction after September 18, 2015, and on or before December 6, 2022.

(b) ***Prevention of Significant Deterioration (PSD) and title V thresholds for Greenhouse Gases.***

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Clean Air Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 71.2.

[89 FR 17036, Mar. 8, 2024]

§ 60.5365a Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section, that is located within the Crude Oil and Natural Gas source category, as defined in § 60.5430a, for which you commence construction, modification, or reconstruction after September 18, 2015, and on or before December 6, 2022. Facilities located inside and including the Local Distribution Company (LDC) custody transfer station are not subject to this subpart. An affected facility must continue to comply with the requirements of this subpart until it begins complying with a more stringent requirement, that applies to the same affected facility, in an approved, and effective, state or Federal plan that implements subpart OOOOc of this part, or modifies or reconstructs after December 6, 2022, and thus becomes subject to subpart OOOOb of this part.

(a) Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing. The provisions of this paragraph do not affect the affected facility status of well sites for the purposes of § 60.5397a. The provisions of paragraphs (a)(1) through (4) of this section apply to wells that are hydraulically refractured:

(1) A well that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of § 60.5375a(a)(1) through (4) are met. However, hydraulic refracturing of a well constitutes a modification of the well site for purposes of paragraph (i)(3)(iii) of this section, regardless of affected facility status of the well itself.

(2) A well completion operation following hydraulic refracturing not conducted pursuant to § 60.5375a(a)(1) through (4) is a modification to the well.

(3) Except as provided in § 60.5365a(i)(3)(iii), refracturing of a well, by itself, does not affect the modification status of other equipment, process units, storage vessels, compressors, pneumatic pumps, or pneumatic controllers.

(4) A well initially constructed after September 18, 2015, and on or before December 6, 2022, that conducts a well completion operation following hydraulic refracturing is considered an affected facility regardless of this provision.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(d) Each pneumatic controller affected facility:

(1) Each pneumatic controller affected facility not located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

(2) Each pneumatic controller affected facility located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller.

(e) Each storage vessel affected facility, which is a single storage vessel as specified in paragraph (e)(1), (2), or (3) of this section.

(1) A single storage vessel that commenced construction, reconstruction, or modification after September 18, 2015, and on or before November 16, 2020, is a storage vessel affected facility if its potential for VOC emissions is equal to or greater than 6 tons per year (tpy) as determined according to this paragraph (e)(1). The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput (as defined in § 60.5430a) determined for a 30-day period prior to the applicable emission determination deadline specified in paragraphs (e)(2)(i) and (ii) of this section, except as provided in paragraph (e)(5)(iv). The determination may take into account requirements under a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or tribal authority.

(2) Except as specified in paragraph (e)(3) of this section, a single storage vessel that commenced construction, reconstruction or modification after November 16, 2020, is a storage vessel affected facility if the potential for VOC emissions is equal to or greater than 6 tpy as determined according to paragraph (e)(2)(i) or (ii) of this section, except as provided in paragraph (e)(5)(iv) of this section. The determination may take into account requirements under a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or tribal authority. The potential for VOC emissions is calculated on an individual storage vessel basis and is not averaged across the number of storage vessels at the site.

(i) For each storage vessel receiving liquids pursuant to the standards for well affected facilities in § 60.5375a, including wells subject to § 60.5375a(f), you must determine the potential for VOC emissions within 30 days after startup of production of the well, except as provided in paragraph (e)(5)(iv) of this section. The potential for VOC emissions must be calculated for each individual storage vessel using a generally accepted model or calculation methodology, based on the maximum average daily throughput, as defined in § 60.5430a, determined for a 30-day period of production.

(ii) For each storage vessel located at a compressor station or onshore natural gas processing plant, you must determine the potential for VOC emissions prior to startup of the compressor station or onshore natural gas processing plant using either method described in paragraph (e)(2)(ii)(A) or (B) of this section.

(A) Determine the potential for VOC emissions using a generally accepted model or calculation methodology and based on the throughput established in a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or tribal authority; or

(B) Determine the potential for VOC emissions using a generally accepted model or calculation methodology and based on projected maximum average daily throughput. Maximum average daily throughput is determined using a generally accepted engineering model (*e.g.,* volumetric condensate rates from the storage vessels based on the maximum gas throughput capacity of each producing facility) to project the maximum average daily throughput for the storage vessel.

(3) If a storage vessel battery, which consists of two or more storage vessels, meets all of the design and operational criteria specified in paragraphs (e)(3)(i) through (iv) of this section through legally and practicably enforceable standards in a permit or other requirement established under Federal, state, local, or tribal authority, then each storage vessel in such storage vessel battery is a storage vessel affected facility.

(i) The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels;

(ii) The storage vessels must be equipped with a closed vent system that is designed, operated, and maintained to route the vapors back to the process or to a control device;

(iii) The vapors collected in paragraph (e)(3)(i) of this section must be routed back to the process or to a control device that reduces VOC emissions by at least 95.0 percent; and

(iv) The VOC emissions, averaged across the number of storage vessels in the battery meeting all of the criteria of paragraphs (e)(3)(i) through (iii) of this section, are equal to or greater than 6 tpy.

(v) If a storage vessel battery meeting all of the criteria specified in paragraphs (e)(3)(i) through (iii) of this section through legally and practicably enforceable standards in a permit or other requirements established under Federal, state, local, or tribal authority, emits less than 6 tpy of VOC emissions averaged across the number of storage vessels in the battery, none of the storage vessels in the battery are storage vessel affected facilities.

(4) A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart.

(5) For storage vessels not subject to a legally and practicably enforceable limit in an operating permit or other requirement established under Federal, state, local, or tribal authority, any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of potential for VOC emissions for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(5)(i) through (iv) of this section.

(i) You meet the cover requirements specified in § 60.5411a(b).

(ii) You meet the closed vent system requirements specified in § 60.5411a(c) and (d).

(iii) You must maintain records that document compliance with paragraphs (e)(5)(i) and (ii) of this section.

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs (e)(5)(i) and (ii) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(6) The requirements of this paragraph (e)(6) apply to each storage vessel affected facility immediately upon startup, startup of production, or return to service. A storage vessel affected facility that is reconnected to the original source of liquids is a storage vessel affected facility subject to the same requirements that applied before being removed from service. Any storage vessel that is used to replace any storage vessel affected facility is subject to the same requirements that applied to the storage vessel affected facility being replaced.

(7) A storage vessel with a capacity greater than 100,000 gallons used to recycle water that has been passed through two stage separation is not a storage vessel affected facility.

(f) The group of all equipment within a process unit at an onshore natural gas processing plant is an affected facility.

(1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by §§ 60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the provisions of §§ 60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a.

(3) The equipment within a process unit of an affected facility located at onshore natural gas processing plants and described in paragraph (f) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG, or GGGa of this part.

(g) Sweetening units located at onshore natural gas processing plants that commenced construction, modification, or reconstruction after September 18, 2015, and on or before November 16, 2020, and sweetening units that commence construction, modification, or reconstruction after November 16, 2020.

(1) Each sweetening unit that processes natural gas produced from either onshore or offshore wells is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in § 60.5423a(c) but are not required to comply with §§ 60.5405a through 60.5407a and §§ 60.5410a(g) and 60.5415a(g).

(4) Sweetening facilities producing acid gas that is completely re-injected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§ 60.5405a through 60.5407a, 60.5410a(g), 60.5415a(g), and 60.5423a.

(h) Each pneumatic pump affected facility:

(1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump.

(2) For well sites, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump. A single natural gas-driven diaphragm pump that is in operation less than 90 days per calendar year is not an affected facility under this subpart provided the owner/operator keeps records of the days of operation each calendar year and submits such records to the EPA Administrator (or delegated enforcement authority) upon request. For the purposes of this section, any period of operation during a calendar day counts toward the 90 calendar day threshold.

(i) Except as provided in § 60.5365a(i)(2), the collection of fugitive emissions components at a well site, as defined in § 60.5430a, is an affected facility.

(1) [Reserved]

(2) A well site that only contains one or more wellheads is not an affected facility under this subpart. The affected facility status of a separate tank battery surface site has no effect on the affected facility status of a well site that only contains one or more wellheads.

(3) For purposes of § 60.5397a, a “modification” to a well site occurs when:

(i) A new well is drilled at an existing well site;

(ii) A well at an existing well site is hydraulically fractured; or

(iii) A well at an existing well site is hydraulically refractured.

(4) For purposes of § 60.5397a, a “modification” to an existing source separate tank battery surface site occurs when:

(i) Any of the actions in paragraphs (i)(3)(i) through (iii) of this section occurs at an existing source separate tank battery surface site;

(ii) A well sending production to an existing source separate tank battery site is modified, as defined in paragraphs (i)(3)(i) through (iii) of this section; or

(iii) A well site subject to the requirements in § 60.5397a removes all major production and processing equipment, as defined in § 60.5430a, such that it becomes a wellhead only well site and sends production to an existing source separate tank battery surface site.

(j) The collection of fugitive emissions components at a compressor station, as defined in § 60.5430a, is an affected facility. For purposes of § 60.5397a, a “modification” to a compressor station occurs when:

(1) An additional compressor is installed at a compressor station; or

(2) One or more compressors at a compressor station is replaced by one or more compressors of greater total horsepower than the compressor(s) being replaced. When one or more compressors is replaced by one or more compressors of an equal or smaller total horsepower than the compressor(s) being replaced, installation of the replacement compressor(s) does not trigger a modification of the compressor station for purposes of § 60.5397a.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57070, Sept. 14, 2020; 85 FR 57438, Sept. 15, 2020; 89 FR 17037, Mar. 8, 2024]

§ 60.5370a When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than August 2, 2016 or upon startup, whichever is later.

(b) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating 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, opacity observations, review of operating and maintenance procedures, and inspection of the source. The provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

§ 60.5371a What standards apply to super-emitter events?

This section applies to super-emitter events. For purposes of this section, a super-emitter event is defined as any emissions event that is located at or near an oil and gas facility (*e.g.,* individual well site, natural gas processing plant or compressor station) and that is detected using remote detection methods and has a quantified emission rate of 100 kg/hr of methane or greater. Upon receiving a notification of a super emitter event issued by the EPA under § 60.5371b(c) in subpart OOOOb of this part, owners or operators must take the actions listed in paragraphs (a) and (b) of this section. Within 5 calendar days of receiving a notification from the EPA of a super-emitter event, the owner or operator of an oil and natural gas facility (*e.g.,* a well site, centralized production facility, natural gas processing plant, or compressor station) must initiate a super-emitter event investigation.

(a) ***Identification of super-emitter events.***

(1) If you do not own or operate an oil and natural gas facility within 50 meters from the latitude and longitude provided in the notification subject to the regulation under this subpart, report this result to the EPA under paragraph (e) of this section. Your super-emitter event investigation is deemed complete under this subpart.

(2) If you own or operate an oil and natural gas facility within 50 meters from the latitude and longitude provided in the notification, and there is an affected facility or associated equipment subject to this subpart onsite, you must investigate to determine the source of the super-emitter event in accordance with paragraph (a)(2) of this section, maintain records of your investigation, and report the results in accordance with paragraph (b) of this section.

(3) The investigation required by paragraph (a)(2) of this section may include but is not limited to the actions specified below in paragraphs (a)(3)(i) through (iv) of this section.

(i) Review any maintenance activities or process activities from the affected facilities subject to regulation under this subpart, starting from the date of detection of the super-emitter event as identified in the notification, until the date of investigation, to determine if the activities indicate any potential source(s) of the super-emitter event emissions.

(ii) Review all monitoring data from control devices (*e.g.,* flares) from the affected facilities subject to regulation under this subpart from the initial date of detection of the super-emitter event as identified in the notification, until the date of receiving the notification from the EPA to identify malfunctions of control devices or periods when the control devices were not in compliance with applicable requirements and that indicate a potential source of the super-emitter event emissions.

(iii) If you conducted a fugitive emissions survey in accordance with § 60.5397a between the initial date of detection of the super-emitter event as identified in the notification and the date the notification from the EPA was received, review the results of the survey to identify any potential source(s) of the super-emitter event emissions.

(iv) Screen the entire facility with OGI, Method 21 of appendix A-7 to this part, or an alternative test method(s) approved per § 60.5398b(d) of subpart OOOOb of this part, to determine if a super-emitter event is present.

(b) ***Super-emitter event report.*** You must submit the results of the super-emitter event investigation conducted under paragraph (a) of this section to the EPA in accordance with paragraph (b)(1) of this section. If the super-emitter event (*i.e.,* emission at 100 kg/hr of methane or more) is ongoing at the time of this initial report, submit the additional information in accordance with paragraph (b)(2) of this section. You must attest to the information included in the report as specified in paragraph (b)(3) of this section.

(1) Within 15 days of receiving a notification from the EPA under § 60.5371b(c), you must submit a report of the super-emitter event investigation conducted under paragraph (a) of this section through the Super-Emitter Program Portal, at *www.epa.gov/super-emitter.* You must include the applicable information in paragraphs (b)(1)(i) through (viii) of this section in the report. If you have identified a demonstrable error in the notification, the report may include a statement of the demonstrable error.

(i) Notification Report ID of the super-emitter event notification (which is provided in the EPA notification).

(ii) Identification of whether you are the owner or operator of an oil and natural gas facility within 50 meters from the latitude and longitude provided in the EPA notification. If you do not own or operate an oil and natural gas facility within 50 meters from the latitude and longitude provided in the EPA notification, you are not required to report the information in paragraphs (b)(1)(iii) through (viii) of this section.

(iii) General identification information for the facility, including facility name, the physical address, applicable ID Number (*e.g.,* EPA ID Number, API Well ID Number), the owner or operator or responsible official (where applicable), and their email address.

(iv) Identification of whether there is an affected facility or associated equipment subject to regulation under this subpart at this oil and natural gas facility.

(v) Indication of whether you were able to identify the source of the super-emitter event. If you indicate you were unable to identify the source of the super-emitter event, you must certify that all applicable investigations specified in paragraphs (a)(2)(i) through (iv) of this section have been conducted for all affected facilities and associated equipment subject to regulation under this subpart that are at this oil and natural gas facility, and you have determined that these affected facilities and associated equipment are not the source of the super-emitter event. If you indicate that you were not able to identify the source of the super-emitter event, you are not required to report the information in paragraphs (b)(1)(vi) through (viii) of this section.

(vi) The source(s) of the super-emitter event.

(vii) Identification of whether the source of the super-emitter event is an affected facility or associated equipment subject to regulation under of this subpart. If the source of the super-emitter event is an affected facility or associated equipment subject to regulation under this subpart, identify the applicable regulation(s) under this subpart.

(viii) Indication of whether the super-emitter event is ongoing at the time of the initial report submittal (*i.e.,* emissions at 100 kg/hr of methane or more).

(A) If the super-emitter event is not ongoing at the time of the initial report submittal, provide the actual (or if not known, estimated) date and time the super-emitter event ended.

(B) If the super-emitter event is ongoing at the time of the initial report submittal, provide a short narrative of your plan to end the super-emitter event, including the targeted end date for the efforts to be completed and the super-emitter event ended.

(2) If the super-emitter event is ongoing at the time of the initial report submittal, within 5 business days of the date the super-emitter event ends you must update your initial report through the Super-Emitter Program Portal, to provide the end date and time of the super-emitter event.

(3) You must sign the following attestation when submitting data into the Super-Emitter Program Portal: "I certify that the information provided in this report regarding the specified super-emitter event was prepared under my direction or supervision. I further certify that the investigations were conducted, and this report was prepared pursuant to the requirements of § 60.5371a(a) and (b). Based

on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that knowingly false statements may be punishable by fine or imprisonment."

[89 FR 17037, Mar. 8, 2024]

§ 60.5375a What GHG and VOC standards apply to well affected facilities?

If you are the owner or operator of a well affected facility as described in § 60.5365a(a) that also meets the criteria for a well affected facility in § 60.5365(a) (in subpart OOOO of this part), you must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with paragraphs (a) through (g) of this section. If you own or operate a well affected facility as described in § 60.5365a(a) that does not meet the criteria for a well affected facility in § 60.5365(a) (in subpart OOOO of this part), you must reduce GHG and VOC emissions by complying with paragraphs (f)(3) and (4) or paragraph (g) of this section for each well completion operation with hydraulic fracturing prior to November 30, 2016, and you must comply with paragraphs (a) through (g) of this section for each well completion operation with hydraulic fracturing on or after November 30, 2016.

(a) Except as provided in paragraph (f) and (g) of this section, for each well completion operation with hydraulic fracturing you must comply with the requirements in paragraphs (a)(1) through (4) of this section. You must maintain a log as specified in paragraph (b) of this section.

(1) For each stage of the well completion operation, as defined in § 60.5430a, follow the requirements specified in paragraphs (a)(1)(i) through (iii) of this section.

(i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. The separator may be a production separator, but the production separator also must be designed to accommodate flowback. Any gas present in the initial flowback stage is not subject to control under this section.

(ii) During the separation flowback stage, route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the recovered liquids into the well or another well, or route the recovered liquids to a collection system. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an onsite fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is technically infeasible to route the recovered gas as required above, follow the requirements in paragraph (a)(3) of this section. If, at any time during the separation flowback stage, it is technically infeasible for a separator to function, you must comply with paragraph (a)(1)(i) of this section.

(iii) You must have the separator onsite or otherwise available for use at a centralized facility or well pad that services the well affected facility during well completions. The separator must be available and ready for use to comply with paragraph (a)(1)(ii) of this section during the entirety of the flowback period, except as provided in paragraphs (a)(1)(iii)(A) through (C) of this section.

(A) A well that is not hydraulically fractured or refractured with liquids, or that does not generate condensate, intermediate hydrocarbon liquids, or produced water such that there is no liquid collection system at the well site is not required to have a separator onsite.

(B) If conditions allow for liquid collection, then the operator must immediately stop the well completion operation, install a separator, and restart the well completion operation in accordance with § 60.5375a(a)(1).

(C) The owner or operator of a well that meets the criteria of paragraph (a)(1)(iii)(A) or (B) of this section must submit the report in § 60.5420a(b)(2) and maintain the records in § 60.5420a(c)(1)(iii).

(2) [Reserved]

(3) If it is technically infeasible to route the recovered gas as required in § 60.5375a(a)(1)(ii), then you must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(4) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

(b) You must maintain a log for each well completion operation at each well affected facility. The log must be completed on a daily basis for the duration of the well completion operation and must contain the records specified in § 60.5420a(c)(1)(iii).

(c) You must demonstrate initial compliance with the standards that apply to well affected facilities as required by § 60.5410a(a).

(d) You must demonstrate continuous compliance with the standards that apply to well affected facilities as required by § 60.5415a(a).

(e) You must perform the required notification, recordkeeping and reporting as required by § 60.5420a(a)(2), (b)(1) and (2), and (c)(1).

(f) For each well affected facility specified in paragraphs (f)(1) and (2) of this section, you must comply with the requirements of paragraphs (f)(3) and (4) of this section.

(1) Each well completion operation with hydraulic fracturing at a wildcat or delineation well.

(2) Each well completion operation with hydraulic fracturing at a non-wildcat low pressure well or non-delineation low pressure well.

(3) You must comply with either paragraph (f)(3)(i) or (f)(3)(ii) of this section, unless you meet the requirements in paragraph (g) of this section. You must also comply with paragraph (b) of this section.

(i) Route all flowback to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(ii) Route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(4) You must submit the notification as specified in § 60.5420a(a)(2), submit annual reports as specified in § 60.5420a(b)(1) and (2) and maintain records specified in § 60.5420a(c)(1)(iii) for each wildcat and delineation well. You must submit the notification as specified in § 60.5420a(a)(2), submit annual reports as specified in § 60.5420a(b)(1) and (2), and maintain records as specified in § 60.5420a(c)(1)(iii) and (vii) for each low pressure well.

(g) For each well affected facility with less than 300 scf of gas per stock tank barrel of oil produced, you must comply with paragraphs (g)(1) and (2) of this section.

(1) You must maintain records specified in § 60.5420a(c)(1)(vi).

(2) You must submit reports specified in § 60.5420a(b)(1) and (2).

[81 FR 35898, June 3, 2016, as amended at 85 FR 57070, Sept. 14, 2020; 85 FR 57439, Sept. 15, 2020; 89 FR 17038, Mar. 8, 2024]

§ 60.5380a What GHG and VOC standards apply to centrifugal compressor affected facilities?

You must comply with the GHG and VOC standards in paragraphs (a) through (d) of this section for each centrifugal compressor affected facility.

(a)

(1) You must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411a(b). The cover must be connected through a closed vent system that meets the requirements of § 60.5411a(a) and (d) and the closed vent system must be routed to a control device that meets the conditions specified in § 60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5410a(b).

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5415a(b).

(d) You must perform the reporting as required by § 60.5420a(b)(1) and (3), and the recordkeeping as required by § 60.5420a(c)(2), (6) through (11), and (17), as applicable.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57070, Sept. 14, 2020; 89 FR 17038, Mar. 8, 2024]

§ 60.5385a What GHG and VOC standards apply to reciprocating compressor affected facilities?

You must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section, or you must comply with paragraph (a)(3) of this section.

(1) On or before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, August 2, 2016, or the date of the most recent reciprocating compressor rod packing replacement, whichever is latest.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

(3) Collect the methane and VOC emissions from the rod packing using a rod packing emissions collection system that operates under negative pressure and route the rod packing emissions to a process through a closed vent system that meets the requirements of § 60.5411a(a) and (d).

(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5410a(c).

(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5415a(c).

(d) You must perform the reporting as required by § 60.5420a(b)(1) and (4) and the recordkeeping as required by § 60.5420a(c)(3), (6) through (9), and (17), as applicable.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57070, Sept. 14, 2020; 85 FR 57439, Sept. 15, 2020; 89 FR 17038, Mar. 8, 2024]

§ 60.5390a What GHG and VOC standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the GHG and VOC standards, based on natural gas as a surrogate for GHG and VOC, in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from the requirements in paragraph (b)(1) or (c)(1) of this section.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety and positive actuation. However, you must tag such pneumatic controller with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller, as required in § 60.5420a(c)(4)(ii).

(b)

(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in § 60.5420a(c)(4)(iv).

(c)

(1) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in § 60.5420a(c)(4)(iii).

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5410a(d).

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5415a(d).

(f) You must perform the reporting as required by § 60.5420a(b)(1) and (5) and the recordkeeping as required by § 60.5420a(c)(4).

[81 FR 35898, June 3, 2016, as amended at 85 FR 57070, Sept. 14, 2020; 89 FR 17038, Mar. 8, 2024]

§ 60.5393a What GHG and VOC standards apply to pneumatic pump affected facilities?

For each pneumatic pump affected facility you must comply with the GHG and VOC standards, based on natural gas as a surrogate for GHG and VOC, in either paragraph (a) or (b) of this section, as applicable, on or after November 30, 2016.

(a) Each pneumatic pump affected facility at a natural gas processing plant must have a natural gas emission rate of zero.

(b) For each pneumatic pump affected facility at a well site you must reduce natural gas emissions by 95.0 percent, except as provided in paragraphs (b)(3), (4), and (5) of this section.

(1)-(2) [Reserved]

(3) You are not required to install a control device solely for the purpose of complying with the 95.0 percent reduction requirement of paragraph (b) of this section. If you do not have a control device installed on site by the compliance date and you do not have the ability to route to a process, then you must comply instead with the provisions of paragraphs (b)(3)(i) and (ii) of this section. For the purposes of this section, boilers and process heaters are not considered control devices. In addition, routing emissions from pneumatic pump discharges to boilers and process heaters is not considered routing to a process.

(i) Submit a certification in accordance with § 60.5420a(b)(8)(i)(A) in your next annual report, certifying that there is no available control device or process on site and maintain the records in § 60.5420a(c)(16)(i) and (ii).

(ii) If you subsequently install a control device or have the ability to route to a process, you are no longer required to comply with paragraph (b)(3)(i) of this section and must submit the information in § 60.5420a(b)(8)(ii) in your next annual report and maintain the records in § 60.5420a(c)(16)(i), (ii), and

(iii) . You must be in compliance with the requirements of paragraph (b) of this section within 30 days of startup of the control device or within 30 days of the ability to route to a process.

(4) If the control device available on site is unable to achieve a 95-percent reduction and there is no ability to route the emissions to a process, you must still route the pneumatic pump affected facility's emissions to that control device. If you route the pneumatic pump affected facility to a control device installed on site that is designed to achieve less than a 95-percent reduction, you must submit the information specified in § 60.5420a(b)(8)(i)(C) in your next annual report and maintain the records in § 60.5420a(c)(16)(iii).

(5) If an owner or operator determines, through an engineering assessment, that routing a pneumatic pump to a control device or a process is technically infeasible, the requirements specified in paragraphs (b)(5)(i) through (iv) of this section must be met.

(i) The owner or operator shall conduct the assessment of technical infeasibility in accordance with the criteria in paragraph (b)(5)(iii) of this section and have it certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of the pneumatic pump in accordance with paragraph (b)(5)(ii) of this section.

(ii) The following certification, signed and dated by the qualified professional engineer or in-house engineer, shall state: "I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was prepared pursuant to the requirements of § 60.5393a(b)(5)(iii). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(iii) The assessment of technical infeasibility to route emissions from the pneumatic pump to an existing control device onsite or to a process shall include, but is not limited to, safety considerations, distance from the control device or process, pressure losses and differentials in the closed vent system, and the ability of the control device or process to handle the pneumatic pump emissions which are routed to them. The assessment of technical infeasibility shall be prepared under the direction or supervision of the qualified professional engineer or in-house engineer who signs the certification in accordance with paragraph (b)(5)(ii) of this section.

(iv) The owner or operator shall maintain the records specified in § 60.5420a(c)(16)(iv).

(6) If the pneumatic pump is routed to a control device or a process and the control device or process is subsequently removed from the location or is no longer available, you are no longer required to be in compliance with the requirements of paragraph (b) of this section, and instead must comply with paragraph (b)(3) of this section and report the change in the next annual report in accordance with § 60.5420a(b)(8)(ii).

(c) If you use a control device or route to a process to reduce emissions, you must connect the pneumatic pump affected facility through a closed vent system that meets the requirements of §§ 60.5411a(d) and (e), 60.5415a(b)(3), and 60.5416a(d).

(d) You must demonstrate initial compliance with standards that apply to pneumatic pump affected facilities as required by § 60.5410a(e).

(e) You must perform the reporting as required by § 60.5420a(b)(1) and (8) and the recordkeeping as required by § 60.5420a(c)(6) through (10), (16), and (17), as applicable.

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017; 85 FR 57070, Sept. 14, 2020; 85 FR 57439, Sept. 15, 2020; 89 FR 17038, Mar. 8, 2024]

§ 60.5395a What VOC standards apply to storage vessel affected facilities?

Each storage vessel affected facility must comply with the VOC standards in this section, except as provided in paragraph (e) of this section.

(a) You must comply with the requirements of paragraphs (a)(1) and (2) of this section. After 12 consecutive months of compliance with paragraph (a)(2) of this section, you may continue to comply with paragraph (a)(2) of this section, or you may comply with paragraph (a)(3) of this section, if applicable. If you choose to meet the requirements in paragraph (a)(3) of this section, you are not required to comply with the requirements of paragraph (a)(2) of this section except as provided in paragraphs (a)(3)(i) and (ii) of this section.

(1) Determine the potential for VOC emissions in accordance with § 60.5365a(e).

(2) Reduce VOC emissions by 95.0 percent within 60 days after startup. For storage vessel affected facilities receiving liquids pursuant to the standards for well affected facilities in § 60.5375a(a)(1)(i) or (ii), you must achieve the required emissions reductions within 60 days after startup of production as defined in § 60.5430a.

(3) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology, and the calculations must be based on the average throughput for the month. You may no longer comply with this paragraph and must instead comply with paragraph (a)(2) of this section if your storage vessel affected facility meets the conditions specified in paragraphs (a)(3)(i) or (ii) of this section.

(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (a)(2) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.

(ii) If the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (a)(2) of this section within 30 days of the monthly determination.

(b) ***Control requirements.***

(1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce VOC emissions from your storage vessel affected facility, you must equip the storage vessel with a cover that meets the requirements of § 60.5411a(b) and is connected through a closed vent system that meets the requirements of § 60.5411a(c) and (d), and you must route emissions to a control device that meets the conditions specified in § 60.5412a(c) or (d). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of § 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(c) Requirements for storage vessel affected facilities that are removed from service or returned to service. If you remove a storage vessel affected facility from service, you must comply with paragraphs (c)(1) through (3) of this section. A storage vessel is not an affected facility under this subpart for the period that it is removed from service.

(1) For a storage vessel affected facility to be removed from service, you must comply with the requirements of paragraphs (c)(1)(i) and (ii) of this section.

(i) You must completely empty and degas the storage vessel, such that the storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification as required in § 60.5420a(b)(6)(v) in your next annual report, identifying each storage vessel affected facility removed from service during the reporting period and the date of its removal from service.

(2) If a storage vessel identified in paragraph (c)(1)(ii) of this section is returned to service, you must determine its affected facility status as provided in § 60.5365a(e).

(3) For each storage vessel affected facility returned to service during the reporting period, you must submit a notification in your next annual report as required in § 60.5420a(b)(6)(vi), identifying each storage vessel affected facility and the date of its return to service.

(d) Compliance, notification, recordkeeping, and reporting. You must comply with paragraphs (d)(1) through (3) of this section.

(1) You must demonstrate initial compliance with standards as required by § 60.5410a(h) and (i).

(2) You must demonstrate continuous compliance with standards as required by § 60.5415a(e)(3).

(3) You must perform the required reporting as required by § 60.5420a(b)(1) and (6) and the recordkeeping as required by § 60.5420a(c)(5) through (8), (12) through (14), and (17), as applicable.

(e) ***Exemptions.*** This subpart does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, and 40 CFR part 63, subparts G, CC, HH, or WW.

[77 FR 49542, Aug. 16, 2012, as amended at 85 FR 57440, Sept. 15, 2020]

§ 60.5397a What fugitive emissions GHG and VOC standards apply to the affected facility which is the collection of fugitive emissions components at a well site and the affected facility which is the collection of fugitive emissions components at a compressor station?

For each affected facility under § 60.5365a(i) and (j), you must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with the requirements of paragraphs (a) through (j) of this section. The requirements in this section are independent of the closed vent system and cover requirements in § 60.5411a. Alternatively, you may comply with the requirements of § 60.5398b, including the notification, recordkeeping, and reporting requirements outlined in § 60.5424b. For the purpose of this subpart, compliance with the requirements in § 60.5398b will be deemed compliance with this section. When complying with § 60.5398b, the definitions in § 60.5430b shall apply for those activities conducted under § 60.5398b.

(a) You must monitor all fugitive emission components, as defined in § 60.5430a, in accordance with paragraphs (b) through (g) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (h) of this section. You must keep records in accordance with paragraph (i) of this section and report in accordance with paragraph (j) of this section. For purposes of this section, fugitive emissions are defined as any visible emission from a fugitive emissions component observed using optical gas imaging or an instrument reading of 500 parts per million (ppm) or greater using Method 21 of appendix A-7 to this part.

(b) You must develop an emissions monitoring plan that covers the collection of fugitive emissions components at well sites and compressor stations within each company-defined area in accordance with paragraphs (c) and (d) of this section.

(c) Fugitive emissions monitoring plans must include the elements specified in paragraphs (c)(1) through (8) of this section, at a minimum.

(1) Frequency for conducting surveys. Surveys must be conducted at least as frequently as required by paragraphs (f) and (g) of this section.

(2) Technique for determining fugitive emissions (*i.e.,* Method 21 of appendix A-7 to this part or optical gas imaging meeting the requirements in paragraphs (c)(7)(i) through (vii) of this section).

(3) Manufacturer and model number of fugitive emissions detection equipment to be used.

(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (h) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) If you are using optical gas imaging, your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification, and may either be performed by the facility, by the manufacturer, or by a third party. For the purposes of complying with the fugitive emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.

(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.

(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60g/hr from a quarter inch diameter orifice.

(ii) Procedure for a daily verification check.

(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(v) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (e.g., steam).

(vi) Training and experience needed prior to performing surveys.

(vii) Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.

(8) If you are using Method 21 of appendix A-7 of this part, your plan must also include the elements specified in paragraphs (c)(8)(i) through (iii) of this section. For the purposes of complying with the fugitive emissions monitoring program using Method 21 of appendix A-7 of this part a fugitive emission is defined as an instrument reading of 500 ppm or greater.

(i) ***Verification that your monitoring equipment meets the requirements specified in Section 6.0 of Method 21 at 40 CFR part 60, appendix A-7.*** For purposes of instrument capability, the fugitive emissions definition shall be 500 ppm or greater methane using a FID-based instrument. If you wish to use an analyzer other than a FID-based instrument, you must develop a site-specific fugitive emission definition that would be equivalent to 500 ppm methane using a FID-based instrument (*e.g.,* 10.6 eV PID with a specified isobutylene concentration as the fugitive emission definition would provide equivalent response to your compound of interest).

(ii) ***Procedures for conducting surveys.*** At a minimum, the procedures shall ensure that the surveys comply with the relevant sections of Method 21 at 40 CFR part 60, appendix A-7, including Section 8.3.1.

(iii) ***Procedures for calibration.*** The instrument must be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 of this part. At a minimum, you must also conduct precision tests at the interval specified in Method 21 of appendix A-7 of this part, Section 8.1.2, and a calibration drift assessment at the end of each monitoring day. The calibration drift assessment must be conducted as specified in paragraph (c)(8)(iii)(A) of this section. Corrective action for drift assessments is specified in paragraphs (c)(8)(iii)(B) and (C) of this section.

(A) Check the instrument using the same calibration gas that was used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. If multiple scales are used, record the instrument reading for each scale used. Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage.

(B) If a calibration drift assessment shows a negative drift of more than 10 percent, then all equipment with instrument readings between the fugitive emission definition multiplied by (100 minus the percent of negative drift/divided by 100) and the fugitive emission definition that was monitored since the last calibration must be re-monitored.

(C) If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the fugitive emission definition and below the fugitive emission definition multiplied by (100 plus the percent of positive drift/divided by 100) monitored since the last calibration may be re-monitored.

(d) Each fugitive emissions monitoring plan must include the elements specified in paragraphs (d)(1) through (3) of this section, at a minimum, as applicable.

(1) If you are using optical gas imaging, your plan must include procedures to ensure that all fugitive emissions components are monitored during each survey. Example procedures include, but are not limited to, a sitemap with an observation path, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components.

(2) If you are using Method 21 of appendix A-7 of this part, your plan must include a list of fugitive emissions components to be monitored and method for determining the location of fugitive emissions components to be monitored in the field (*e.g.,* tagging, identification on a process and instrumentation diagram, etc.).

(3) Your fugitive emissions monitoring plan must include the written plan developed for all of the fugitive emissions components designated as difficult-to-monitor in accordance with paragraph (g)(3) of this section, and the written plan for fugitive emissions components designated as unsafe-to-monitor in accordance with paragraph (g)(4) of this section.

(e) Each monitoring survey shall observe each fugitive emissions component, as defined in § 60.5430a, for fugitive emissions.

(f)

(1) You must conduct an initial monitoring survey within 90 days of the startup of production, as defined in § 60.5430a, for each collection of fugitive emissions components at a new well site or by June 3, 2017, whichever is later. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within 90 days of the startup of production for each collection of fugitive emissions components after the modification or by June 3, 2017, whichever is later. Notwithstanding the preceding deadlines, for each collection of fugitive emissions components at a well site located on the Alaskan North Slope, as defined in § 60.5430a, that starts up production between September and March, you must conduct an initial monitoring survey within 6 months of the startup of production for a new well site, within 6 months of the first day of production after a modification of the collection of fugitive emission components, or by the following June 30, whichever is latest.

(2) You must conduct an initial monitoring survey within 90 days of the startup of a new compressor station for each collection of fugitive emissions components at the new compressor station or by June 3, 2017, whichever is later. For a modified collection of fugitive emissions components at a compressor station, the initial monitoring survey must be conducted within 90 days of the modification or by June 3, 2017, whichever is later. Notwithstanding the preceding deadlines, for each collection of fugitive emissions components at a new compressor station located on the Alaskan North Slope that starts up between September and March, you must conduct an initial monitoring survey within 6 months of the startup date for new compressor stations, within 6 months of the modification, or by the following June 30, whichever is latest.

(g) A monitoring survey of each collection of fugitive emissions components at a well site or at a compressor station must be performed at the frequencies specified in paragraphs (g)(1) and (2) of this section, with the exceptions noted in paragraphs (g)(3) through (6) of this section.

(1) Except as provided in this paragraph (g)(1), a monitoring survey of each collection of fugitive emissions components at a well site must be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart and no more than 7 months apart. A monitoring survey of each collection of fugitive emissions components at a well site located on the Alaskan North Slope must be conducted at least annually. Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart.

(2) Except as provided in this paragraph (g)(2), a monitoring survey of the collection of fugitive emissions components at a compressor station must be conducted at least quarterly after the initial survey. Consecutive quarterly monitoring surveys must be conducted at least 60 days apart. A monitoring survey of the collection of fugitive emissions components at a compressor station located on the Alaskan North Slope must be conducted at least annually. Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart.

(3) Fugitive emissions components that cannot be monitored without elevating the monitoring personnel more than 2 meters above the surface may be designated as difficult-to-monitor. Fugitive emissions components that are designated difficult-to-monitor must meet the specifications of paragraphs (g)(3)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated difficult-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by paragraphs (b), (c), and (d) of this section.

(ii) The plan must include the identification and location of each fugitive emissions component designated as difficult-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as difficult-to-monitor is difficult-to-monitor.

(iv) The plan must include a schedule for monitoring the difficult-to-monitor fugitive emissions components at least once per calendar year.

(4) Fugitive emissions components that cannot be monitored because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey may be designated as unsafe-to-monitor. Fugitive emissions components that are designated unsafe-to-monitor must meet the specifications of paragraphs (g)(4)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated unsafe-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by paragraphs (b), (c), and (d) of this section.

(ii) The plan must include the identification and location of each fugitive emissions component designated as unsafe-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as unsafe-to-monitor is unsafe-to-monitor.

(iv) The plan must include a schedule for monitoring the fugitive emissions components designated as unsafe-to-monitor.

(5) You are no longer required to comply with the requirements of paragraph (g)(1) of this section when the owner or operator removes all major production and processing equipment, as defined in § 60.5430a, such that the well site becomes a wellhead only well site. If any major production and processing equipment is subsequently added to the well site, then the owner or operator must comply with the requirements in paragraphs (f)(1) and (g)(1) of this section.

(6) The requirements of paragraph (g)(2) of this section are waived for any collection of fugitive emissions components at a compressor station located within an area that has an average calendar month temperature below 0 °F for two of three consecutive calendar months of a quarterly monitoring period. The calendar month temperature average for each month within the quarterly monitoring period must be determined using historical monthly average temperatures over the previous three years as reported by a National Oceanic and Atmospheric Administration source or other source approved by the Administrator. The requirements of paragraph (g)(2) of this section shall not be waived for two consecutive quarterly monitoring periods.

(h) Each identified source of fugitive emissions shall be repaired, as defined in § 60.5430a, in accordance with paragraphs (h)(1) and (2) of this section.

(1) A first attempt at repair shall be made no later than 30 calendar days after detection of the fugitive emissions.

(2) Repair shall be completed as soon as practicable, but no later than 30 calendar days after the first attempt at repair as required in paragraph (h)(1) of this section.

(3) Delay of repair will be allowed if the conditions in paragraphs (h)(3)(i) or (ii) of this section are met.

(i) If the repair is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown for maintenance, scheduled well shutdown, scheduled well shut-in, after a scheduled vent blowdown, or within 2 years of detecting the fugitive emissions, whichever is earliest. For purposes of this paragraph (h)(3), a vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel.

(ii) If the repair requires replacement of a fugitive emissions component or a part thereof, but the replacement cannot be acquired and installed within the repair timelines specified in paragraphs (h)(1) and (2) of this section due to either of the conditions specified in paragraphs (h)(3)(ii)(A) or (B) of this section, the repair must be completed in accordance with paragraph (h)(3)(ii)(C) of this section and documented in accordance with § 60.5420a(c)(15)(vii)(I).

(A) Valve assembly supplies had been sufficiently stocked but are depleted at the time of the required repair.

(B) A replacement fugitive emissions component or a part thereof requires custom fabrication.

(C) The required replacement must be ordered no later than 10 calendar days after the first attempt at repair. The repair must be completed as soon as practicable, but no later than 30 calendar days after receipt of the replacement component, unless the repair requires a compressor station or well shutdown. If the repair requires a compressor station or well shutdown, the repair must be completed in accordance with the timeframe specified in paragraph (h)(3)(i) of this section.

(4) Each identified source of fugitive emissions must be resurveyed to complete repair according to the requirements in paragraphs (h)(4)(i) through (iv) of this section, to ensure that there are no fugitive emissions.

(i) The operator may resurvey the fugitive emissions components to verify repair using either Method 21 of appendix A-7 of this part or optical gas imaging.

(ii) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component or the component must be tagged during the monitoring survey when the fugitives were initially found for identification purposes and subsequent repair. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (*e.g.,* the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

(iii) Operators that use Method 21 of appendix A-7 of this part to resurvey the repaired fugitive emissions components are subject to the resurvey provisions specified in paragraphs (h)(4)(iii)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppm above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of Method 21 of appendix A-7 of this part are used.

(B) Operators must use the Method 21 monitoring requirements specified in paragraph (c)(8)(ii) of this section or the alternative screening procedures specified in section 8.3.3 of Method 21 of appendix A-7 of this part.

(iv) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (h)(4)(iv)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.

(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (c)(7) of this section.

(i) Records for each monitoring survey shall be maintained as specified § 60.5420a(c)(15).

(j) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that include the information specified in § 60.5420a(b)(7). Multiple collection of fugitive emissions components at a well site or at a compressor station may be included in a single annual report.

[81 FR 35898, June 3, 2016, as amended at 83 FR 10638, Mar. 12, 2018; 85 FR 57070, Sept. 14, 2020; 85 FR 57440, Sept. 15, 2020; 89 FR 17039, Mar. 8, 2024]

§ 60.5398a What are the alternative means of emission limitations for GHG and VOC from well completions, reciprocating compressors, the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in GHG (in the form of a limitation on emissions of methane) and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under § 60.5375a, § 60.5385a, or § 60.5397a, the Administrator will publish, in the Federal Register, a document permitting the use of that alternative means for the purpose of compliance with § 60.5375a, § 60.5385a, or § 60.5397a. The authority to approve an alternative means of emission limitation is retained by the Administrator and shall not be delegated to States under section 111(c) of the Clean Air Act (CAA).

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

(c) Determination of equivalence to the design, equipment, work practice, or operational requirements of this section will be evaluated by the following guidelines:

(1) The applicant must provide information that is sufficient for demonstrating the alternative means of emission limitation achieves emission reductions that are at least equivalent to the emission reductions that would be achieved by complying with the relevant standards. At a minimum, the application must include the following information:

(i) Details of the specific equipment or components that would be included in the alternative.

(ii) A description of the alternative work practice, including, as appropriate, the monitoring method, monitoring instrument or measurement technology, and the data quality indicators for precision and bias.

(iii) The method detection limit of the technology, technique, or process and a description of the procedures used to determine the method detection limit. At a minimum, the applicant must collect, verify, and submit field data encompassing seasonal variations to support the determination of the method detection limit. The field data may be supplemented with modeling analyses, controlled test site data, or other documentation.

(iv) Any initial and ongoing quality assurance/quality control measures necessary for maintaining the technology, technique, or process, and the timeframes for conducting such measures.

(v) Frequency of measurements. For continuous monitoring techniques, the minimum data availability.

(vi) Any restrictions for using the technology, technique, or process.

(vii) Initial and continuous compliance procedures, including recordkeeping and reporting, if the compliance procedures are different than those specified in this subpart.

(2) For each technology, technique, or process for which a determination of equivalency is requested, the application must provide a demonstration that the emission reduction achieved by the alternative means of emission limitation is at least equivalent to the emission reduction that would be achieved by complying with the relevant standards in this subpart.

(d) Any alternative means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the CAA.

[85 FR 57442, Sept. 15, 2020, as amended at 89 FR 17039, Mar. 8, 2024]

§ 60.5399a What alternative fugitive emissions standards apply to the affected facility which is the collection of fugitive emissions components at a well site and the affected facility which is the collection of fugitive emissions components at a compressor station: Equivalency with state, local, and tribal programs?

This section provides alternative fugitive emissions standards based on programs under state, local, or tribal authorities for the collection of fugitive emissions components, as defined in § 60.5430a, located at well sites and compressor stations. Paragraphs (a) through (e) of this section outline the procedure for submittal and approval of alternative fugitive emissions standards. Paragraphs (f) through (n) provide approved alternative fugitive emissions standards. The terms “fugitive emissions components” and “repaired” are defined in § 60.5430a and must be applied to the alternative fugitive emissions standards in this section. The requirements for a monitoring plan as specified in § 60.5397a(c) and (d) apply to the alternative fugitive emissions standards in this section.

(a) ***Alternative fugitive emissions standards.*** If, in the Administrator's judgment, an alternative fugitive emissions standard will achieve a reduction in methane and VOC emissions at least equivalent to the reductions achieved under § 60.5397a, the Administrator will publish, in the Federal Register, a notice permitting use of the alternative fugitive emissions standard for the purpose of compliance with § 60.5397a. The authority to approve alternative fugitive emissions standards is retained by the Administrator and shall not be delegated to States under section 111(c) of the CAA.

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

(c) ***Evaluation guidelines.*** Determination of alternative fugitive emissions standards to the design, equipment, work practice, or operational requirements of § 60.5397a will be evaluated by the following guidelines:

(1) The monitoring instrument, including the monitoring procedure;

(2) The monitoring frequency;

(3) The fugitive emissions definition;

(4) The repair requirements; and

(5) The recordkeeping and reporting requirements.

(d) ***Approval of alternative fugitive emissions standard.*** Any alternative fugitive emissions standard approved under this section shall:

(1) Constitute a required design, equipment, work practice, or operational standard within the meaning of section 111(h)(1) of the CAA; and

(2) Be made available for use by any owner or operator in meeting the relevant standards and requirements established for affected facilities under § 60.5397a.

(e) ***Notification.***

(1) An owner or operator must notify the Administrator of adoption of the alternative fugitive emissions standards within the first annual report following implementation of the alternative fugitive emissions standard, as specified in § 60.5420a(a)(3).

(2) An owner or operator implementing one of the alternative fugitive emissions standards must submit the reports specified in § 60.5420a(b)(7)(iii). An owner or operator must also maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

(f) ***Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site or a compressor station in the State of California.*** An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a well site or a compressor station in the State of California may elect to comply with the monitoring, repair, and recordkeeping requirements in the California Code of Regulations, title 17, sections 95665-95667, effective January 1, 2020, as an alternative to complying with the requirements in § 60.5397a(f)(1) and (2), (g)(1) through (4), (h), and (i). The information specified in § 60.5420a(b)(7)(iii)(A) and the information specified in either § 60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in § 60.5397a(j).

(g) ***Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site or a compressor station in the State of Colorado.*** An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a well site or a compressor station in the State of Colorado may elect to comply with the monitoring, repair, and recordkeeping requirements in Colorado Regulation 7, Part D, section I.L or II.E, effective February 14, 2020, for well sites and compressor stations, as an alternative to complying with the requirements in § 60.5397a(f)(1) and (2), (g)(1) through (4), (h), and (i), provided the monitoring instrument used is an optical gas imaging or a Method 21 instrument (see appendix A-7 of this part). Monitoring must be conducted on at least a semiannual basis for well sites and compressor stations. If using the alternative in this paragraph (g), the information specified in § 60.5420a(b)(7)(iii)(A) and (C) must be provided in lieu of the requirements in § 60.5397a(j).

(h) ***Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site in the State of Ohio.*** An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a well site in the State of Ohio may elect to comply with the monitoring, repair, and recordkeeping requirements in Ohio General Permits 12.1, Section C.5 and 12.2, Section C.5, effective April 14, 2014, as an alternative to complying with the requirements in § 60.5397a(f)(1), (g)(1), (3), and (4), (h), and (i), provided the monitoring instrument used is optical gas imaging or a Method 21 instrument (see appendix A-7 of this part) with a leak definition and reading of 500 ppm or greater. Monitoring must be conducted on at least a semiannual basis and skip periods cannot be applied. The information specified in § 60.5420a(b)(7)(iii)(A) and the information specified in either § 60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in § 60.5397a(j).

(i) ***Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a compressor station in the State of Ohio.*** An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a compressor station in the State of Ohio may elect to comply with the monitoring, repair, and recordkeeping requirements in Ohio General Permit 18.1, effective February 7, 2017, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is optical gas imaging or a Method 21 instrument (see appendix A-7 to this part) with a leak definition and reading of 500 ppm or greater. Monitoring must be conducted on at least a quarterly basis and skip periods cannot be applied. The information specified in § 60.5420a(b)(7)(iii)(A) and the information specified in either § 60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in § 60.5397a(j).

(j) ***Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site in the State of Pennsylvania.*** An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a well site in the State of Pennsylvania may elect to comply with the monitoring, repair, and recordkeeping requirements in Pennsylvania General Permit 5A, section G, effective August 8, 2018, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is an optical gas imaging or a Method 21 instrument (see appendix A-7 of this part). The information specified in § 60.5420a(b)(7)(iii)(A) and the information specified in either § 60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in § 60.5397a(j).

(k) ***Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a compressor station in the State of Pennsylvania.*** An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a compressor station in the State of Pennsylvania may elect to comply with the monitoring, repair, and recordkeeping requirements in Pennsylvania General Permit 5, section G, effective August 8, 2018, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is an optical gas imaging or a Method 21 instrument (see appendix A-7 of this part). The information specified in § 60.5420a(b)(7)(iii)(A) and the information specified in either § 60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in § 60.5397a(j).

(l) ***Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site in the State of Texas.*** An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a well site in the State of Texas may elect to comply with the monitoring, repair, and recordkeeping requirements in the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, section (e)(6), effective November 8, 2012, or at 30 Texas Administrative Code section 116.620, effective September 4, 2000, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is optical gas imaging or a Method 21 instrument (see appendix A-7 of this part) with a leak definition and reading of 500 ppm or greater. Monitoring must be conducted on at least a semiannual basis and skip periods may not be applied. If using the requirement in this paragraph (l), the information specified in § 60.5420a(b)(7)(iii)(A) and (C) must be provided in lieu of the requirements in § 60.5397a(j).

(m) ***Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a compressor station in the State of Texas.*** An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, located at a compressor in the State of Texas may elect to comply with the monitoring, repair, and recordkeeping requirements in the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, section I(6), effective November 8, 2012, or at 30 Texas Administrative Code section 116.620, effective September 4, 2000, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is optical gas imaging or a Method 21 instrument (see appendix A-7 to this part) with a leak definition and reading of 500 ppm or greater. Monitoring must be conducted on at least a quarterly basis and skip periods may not be applied. If using the alternative in this paragraph (m), the information specified in § 60.5420a(b)(7)(iii)(A) and (C) must be provided in lieu of the requirements in § 60.5397a(j).

(n) ***Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site in the State of Utah.*** An affected facility, which is the collection of fugitive emissions components, as defined in § 60.5430a, and is required to control emissions in accordance with Utah Administrative Code R307-506 and R307-507, located at a well site in the State of Utah may elect to comply with the monitoring, repair, and recordkeeping requirements in the Utah Administrative Code R307-509, effective March 2, 2018, as an alternative to complying with the requirements in § 60.5397a(f)(2), (g)(2) through (4), (h), and (i). If using the alternative in this paragraph (n), the information specified in § 60.5420a(b)(7)(iii)(A) and (C) must be provided in lieu of the requirements in § 60.5397a(j).

[85 FR 57443, Sept. 15, 2020, as amended at 89 FR 17039, Mar. 8, 2024]

§ 60.5400a What equipment leak GHG and VOC standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to the group of all equipment, except compressors, within a process unit located at an onshore natural gas processing plant.

(a) You must comply with the requirements of §§ 60.482-1a(a), (b), (d), and (e), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in § 60.5401a, as soon as practicable but no later than 180 days after the initial startup of the process unit.

(b) You may elect to comply with the requirements of §§ 60.483-1a and 60.483-2a, as an alternative.

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of § 60.5402a.

(d) You must comply with the provisions of § 60.485a except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§ 60.486a and 60.487a except as provided in §§ 60.5401a, 60.5421a, and 60.5422a.

(f) You must use the following provision instead of § 60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in § 60.17) must be used.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57071, Sept. 14, 2020; 85 FR 57445, Sept. 15, 2020; 89 FR 17040, Mar. 8, 2024]

§ 60.5401a What are the exceptions to the equipment leak GHG and VOC standards for affected facilities at onshore natural gas processing plants?

(a) You may comply with the following exceptions to the provisions of § 60.5400a(a) and (b).

(b)

(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in § 60.485a(b) except as provided in §§ 60.5400a(c) and in paragraph (b)(4) of this section, and 60.482-4a(a) through (c) of subpart VVa of this part.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)

(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in § 60.482-9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)

(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are onsite, instead of within 5 days as specified in paragraph (b)(1) of this section and § 60.482-4a(b)(1).

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section may be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of § 60.482-5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§ 60.482-2a(a)(1), 60.482-7a(a), 60.482-11a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the monitoring requirements of §§ 60.482-2a(a)(1), 60.482-7a(a), and 60.482-11a(a) and paragraph (b)(1) of this section.

(f) An owner or operator may use the following provisions instead of § 60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °Celsius (302 °Fahrenheit) as determined by ASTM Method D86-96 (incorporated by reference as specified in § 60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °Celsius (302 °Fahrenheit) as determined by ASTM Method D86-96 (incorporated by reference as specified in § 60.17).

(g) An owner or operator may use the following provisions instead of § 60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in § 60.486a(e)(8). For each scale, divide the arithmetic difference of the most recent calibration and the post-test calibration response by the corresponding calibration gas value, and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the most recent calibration response, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the most recent calibration response, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

[77 FR 49542, Aug. 16, 2012, as amended at 85 FR 57445, Sept. 15, 2020]

§ 60.5402a What are the alternative means of emission limitations for GHG and VOC equipment leaks from onshore natural gas processing plants?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in GHG and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the Federal Register, a document permitting the use of that alternative means for the purpose of compliance with that standard. The document may condition permission on requirements related to the operation and maintenance of the alternative means.

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

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) An application submitted under paragraph (c) of this section must meet the following criteria:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) The application must include operation, maintenance, and other provisions necessary to assure reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under the design, equipment, work practice or operational standard in paragraph (a) of this section by including the information specified in paragraphs (d)(2)(i) through (x) of this section.

(i) A description of the technology or process.

(ii) The monitoring instrument and measurement technology or process.

(iii) A description of performance based procedures (i.e. method) and data quality indicators for precision and bias; the method detection limit of the technology or process.

(iv) The action criteria and level at which a fugitive emission exists.

(v) Any initial and ongoing quality assurance/quality control measures.

(vi) Timeframes for conducting ongoing quality assurance/quality control.

(vii) Field data verifying viability and detection capabilities of the technology or process.

(viii) Frequency of measurements.

(ix) Minimum data availability.

(x) Any restrictions for using the technology or process.

(3) The application must include initial and continuous compliance procedures including recordkeeping and reporting.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57071, Sept. 14, 2020; 89 FR 17040, Mar. 8, 2024]

§ 60.5405a What standards apply to sweetening unit affected facilities?

(a) During the initial performance test required by § 60.8(b), you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

§ 60.5406a What test methods and procedures must I use for my sweetening unit affected facilities?

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

(b) During a performance test required by § 60.8, you must determine the minimum required reduction efficiencies (Z) of SO_2 emissions as required in § 60.5405a(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$$X = KQ_aY$$

Where:
X = average sulfur feed rate, Mg/D (LT/D).
Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).
Y = average H_2S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.
K = (32 kg S/kg-mole)/((24.04 dscm/kg-mole)(1000 kg S/Mg)).
= 1.331×10^{-3}Mg/dscm, for metric units.
= (32 lb S/lb-mole)/((385.36 dscf/lb-mole)(2240 lb S/long ton)).
= 3.707×10^{-5} long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in § 60.5408a or a chromatographic procedure following ASTM E260-96 (incorporated by reference as specified in § 60.17) to determine the H_2S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H_2S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO_2 emissions.

(c) You must determine compliance with the SO_2 standards in § 60.5405a(a) or (b) as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$$R = (100S)/(S + E)$$

(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage vessels. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$$E = C_eQ_{sd}/K_1$$

Where:
E = emission rate of sulfur per run, kg/hr.
C_e = concentration of sulfur equivalent (SO^{2+} reduced sulfur), g/dscm (lb/dscf).
Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).
K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO_2 and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of appendix A-1 of this part to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m^2 or more, and the centroid is more than 1 m (39 in) from the wall.

(i) You must use Method 6 of appendix A-4 of this part to determine the SO_2 concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent. In place of Method 6 of appendix A of this part, you may use ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17).

(ii) You must use Method 15 of appendix A-5 of this part to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft^3/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iii) You must use Method 16A of appendix A-6 of this part or Method 15 of appendix A-5 of this part or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17) to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use Method 2 of appendix A-1 of this part to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

§ 60.5407a What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities?

(a) If your sweetening unit affected facility is subject to the provisions of § 60.5405a(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

(1) The accumulation of sulfur product over each 24-hour period. The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage vessels with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ±2 percent of the 24-hour sulfur accumulation.

(2) The H_2S concentration in the acid gas from the sweetening unit for each 24-hour period. At least one sample per 24-hour period must be collected and analyzed using the equation specified in § 60.5406a(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is within ±20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ±20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) The average acid gas flow rate from the sweetening unit. You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) The sulfur feed rate (X). For each 24-hour period, you must compute X using the equation specified in § 60.5406a(b)(1).

(5) The required sulfur dioxide emission reduction efficiency for the 24-hour period. You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of § 60.5405a(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere. The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405a(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with § 60.5405a(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ±1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of § 60.8 to demonstrate compliance with the standards under § 60.5405a, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under § 60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO_2 equivalent in the gases discharged to the atmosphere. The SO_2 equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405a(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock interval. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in § 60.5406a(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H_2S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

$$R = \frac{K_2 S}{X}$$

Where:
R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.
K_2 = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).
S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).
X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by § 60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of § 60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by § 60.13(c), Performance Specification 2 of appendix B of this part must apply, and Method 6 of appendix A-4 of this part must be used for systems required by paragraph (b) of this section. In place of Method 6 of appendix A-4 of this part, ASME PTC 19.10-1981 (incorporated by reference—see § 60.17) may be used.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57445, Sept. 15, 2020]

§ 60.5408a What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A-80-20-A, Entry II-I-67).

(a) When an instantaneous sample is desired and H_2S concentration is 10 grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than 10 grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) ***Apparatus.*** (See Figure 1 of this subpart.) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top that connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) ***Reagents.***

(1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide (KI) for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml=0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) ***Starch solution.*** Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) ***Procedure.*** Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine through (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then,

Grains H_2S per 100 cubic foot of gas = 100 (D-C)

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S-free gas or air, is required.

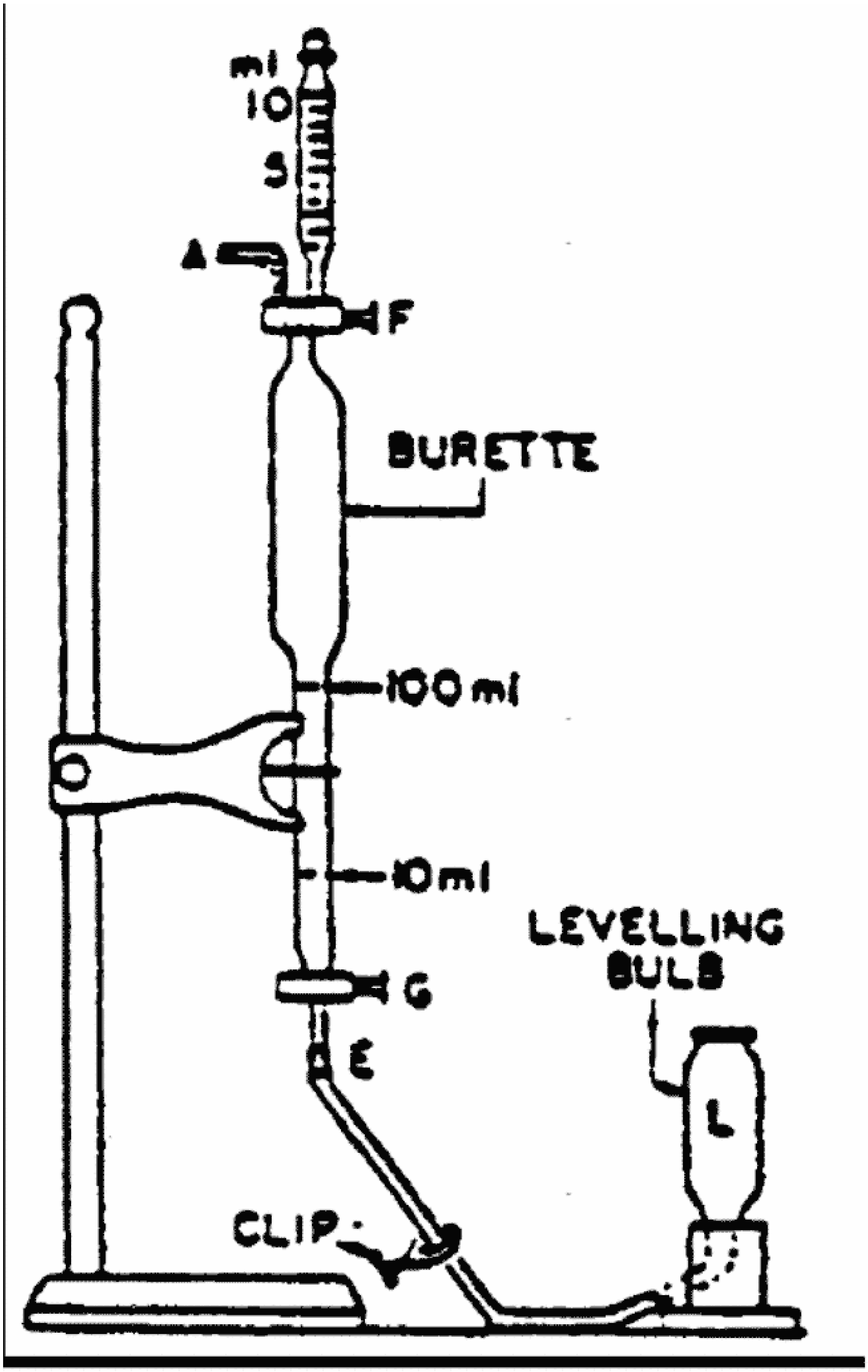

Figure 1. Tutwiler burette (lettered items mentioned in text).

§ 60.5410a How do I demonstrate initial compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, collection of fugitive emissions components at a compressor station, and equipment leaks at onshore natural gas processing plants and sweetening unit affected facilities?

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (k) of this section. Except as otherwise provided in this section, the initial compliance period begins on August 2, 2016, or upon initial startup, whichever is later, and ends no later than 1 year after the initial startup date for your affected facility or no later than 1 year after August 2, 2016. The initial compliance period may be less than 1 full year.

(a) To achieve initial compliance with the methane and VOC standards for each well completion operation conducted at your well affected facility you must comply with paragraphs (a)(1) through (4) of this section.

(1) You must submit the notification required in § 60.5420a(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in § 60.5420a(b)(1) and (2).

(3) You must maintain a log of records as specified in § 60.5420a(c)(1)(i) through (iv), as applicable, for each well completion operation conducted during the initial compliance period. If you meet the exemption for wells with a GOR less than 300 scf per stock barrel of oil produced, you do not have to maintain the records in § 60.5420a(c)(1)(i) through (iv) and must maintain the record in § 60.5420a(c)(1)(vi).

(4) For each well affected facility subject to both § 60.5375a(a)(1) and (3), as an alternative to retaining the records specified in § 60.5420a(c)(1)(i) through (iv), you may maintain records in accordance with § 60.5420a(c)(1)(v) of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(b)

(1) To achieve initial compliance with standards for your centrifugal compressor affected facility you must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required by § 60.5380a(a) and as demonstrated by the requirements of § 60.5413a.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411a(b) that is connected through a closed vent system that meets the requirements of § 60.5411a(a) and (d) and is routed to a control device that meets the conditions specified in § 60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(3) You must conduct an initial performance test as required in § 60.5413a within 180 days after initial startup or by August 2, 2016, whichever is later, and you must comply with the continuous compliance requirements in § 60.5415a(b).

(4) You must conduct the initial inspections required in § 60.5416a(a) and (b).

(5) You must install and operate the continuous parameter monitoring systems in accordance with § 60.5417a(a) through (g), as applicable.

(6) [Reserved]

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in § 60.5420a(b)(1) and (3).

(8) You must maintain the records as specified in § 60.5420a(c)(2), (6) through (11), and (17), as applicable.

(c) To achieve initial compliance with the standards for each reciprocating compressor affected facility you must comply with paragraphs (c)(1) through (4) of this section.

(1) If complying with § 60.5385a(a)(1) or (2), during the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since initial startup, since August 2, 2016, or since the last rod packing replacement, whichever is latest.

(2) If complying with § 60.5385a(a)(3), you must operate the rod packing emissions collection system under negative pressure and route emissions to a process through a closed vent system that meets the requirements of § 60.5411a(a) and (d).

(3) You must submit the initial annual report for your reciprocating compressor as required in § 60.5420a(b)(1) and (4).

(4) You must maintain the records as specified in § 60.5420a(c)(3) for each reciprocating compressor affected facility.

(d) To achieve initial compliance with methane and VOC emission standards for your pneumatic controller affected facility you must comply with the requirements specified in paragraphs (d)(1) through (6) of this section, as applicable.

(1) You must demonstrate initial compliance by maintaining records as specified in § 60.5420a(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required as specified in § 60.5390a(b)(1) or (c)(1).

(2) If you own or operate a pneumatic controller affected facility located at a natural gas processing plant, your pneumatic controller must be driven by a gas other than natural gas, resulting in zero natural gas emissions.

(3) If you own or operate a pneumatic controller affected facility located other than at a natural gas processing plant, the controller manufacturer's design specifications for the controller must indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(4) You must tag each new pneumatic controller affected facility according to the requirements of § 60.5390a(b)(2) or (c)(2).

(5) You must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for your pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of § 60.5420a(b)(1) and (5).

(6) You must maintain the records as specified in § 60.5420a(c)(4) for each pneumatic controller affected facility.

(e) To achieve initial compliance with emission standards for your pneumatic pump affected facility you must comply with the requirements specified in paragraphs (e)(1) through (7) of this section, as applicable.

(1) If you own or operate a pneumatic pump affected facility located at a natural gas processing plant, your pneumatic pump must be driven by a gas other than natural gas, resulting in zero natural gas emissions.

(2) If you own or operate a pneumatic pump affected facility located at a well site, you must reduce emissions in accordance with § 60.5393a(b)(1) or (2), and you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of § 60.5411a(d) and (e).

(3) If you own or operate a pneumatic pump affected facility located at a well site and there is no control device or process available on site, you must submit the certification in § 60.5420a(b)(8)(i)(A).

(4) If you own or operate a pneumatic pump affected facility located at a well site, and you are unable to route to an existing control device or to a process due to technical infeasibility, you must submit the certification in § 60.5420a(b)(8)(i)(B).

(5) If you own or operate a pneumatic pump affected facility located at a well site and you reduce emissions in accordance with § 60.5393a(b)(4), you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of § 60.5411a(d) and (e).

(6) You must submit the initial annual report for your pneumatic pump affected facility required in § 60.5420a(b)(1) and (8).

(7) You must maintain the records as specified in § 60.5420a(c)(6), (8) through (10), (16), and (17), as applicable, for each pneumatic pump affected facility.

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the methane and VOC standards is demonstrated if you are in compliance with the requirements of § 60.5400a.

(g) For sweetening unit affected facilities, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

(1) To determine compliance with the standards for SO_2 specified in § 60.5405a(a), during the initial performance test as required by § 60.8, the minimum required sulfur dioxide emission reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406a(c)(1).

(3) You must submit the results of paragraphs (g)(1) and (2) of this section in the initial annual report submitted for your sweetening unit affected facilities.

(h) For each storage vessel affected facility you must comply with paragraphs (h)(1) through (6) of this section. Except as otherwise provided in this paragraph (h), you must demonstrate initial compliance by August 2, 2016, or within 60 days after startup, whichever is later.

(1) You must determine the potential VOC emission rate as specified in § 60.5365a(e).

(2) You must reduce VOC emissions in accordance with § 60.5395a(a).

(3) If you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of § 60.5411a(b) and is connected through a closed vent system that meets the requirements of § 60.5411a(c) and (d) to a control device that meets the conditions specified in § 60.5412a(d) within 60 days after startup for storage vessels constructed, modified, or reconstructed at well sites with no other wells in production, or upon startup for storage vessels constructed, modified, or reconstructed at well sites with one or more wells already in production.

(4) You must conduct an initial performance test as required in § 60.5413a within 180 days after initial startup or within 180 days of August 2, 2016, whichever is later, and you must comply with the continuous compliance requirements in § 60.5415a(e).

(5) You must submit the information required for your storage vessel affected facility in your initial annual report as specified in § 60.5420a(b)(1) and (6).

(6) You must maintain the records required for your storage vessel affected facility, as specified in § 60.5420a(c)(5) through (8), (12) through (14), and (17), as applicable, for each storage vessel affected facility.

(i) For each storage vessel affected facility that complies by using a floating roof, you must submit a statement that you are complying with § 60.112(b)(a)(1) or (2) in accordance with § 60.5395a(b)(2) with the initial annual report specified in § 60.5420a(b).

(j) To achieve initial compliance with the fugitive emission standards for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station you must comply with paragraphs (j)(1) through (5) of this section.

(1) You must develop a fugitive emissions monitoring plan as required in § 60.5397a(b), (c), and (d).

(2) You must conduct an initial monitoring survey as required in § 60.5397a(f).

(3) You must maintain the records specified in § 60.5420a(c)(15).

(4) You must repair each identified source of fugitive emissions for each affected facility as required in § 60.5397a(h).

(5) You must submit the initial annual report for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station compressor station as required in § 60.5420a(b)(1) and (7).

(k) To demonstrate initial compliance with the requirement to maintain the total well site production at or below 15 boe per day based on a rolling 12-month average, as specified in § 60.5397a(a)(2), you must comply with paragraphs (k)(1) through (3) of this section.

(1) You must demonstrate that the total daily combined oil and natural gas production for all wells at the well site is at or below 15 boe per day, based on a 12-month average from the previous 12 months of operation, according to paragraphs (k)(1)(i) through (iii) of this section within 45 days of the end of each month. The rolling 12-month average of the total well site production determined according to paragraph (k)(1)(iii) of this section must be at or below 15 boe per day.

(i) Determine the daily combined oil and natural gas production for each individual well at the well site for the month. To convert gas production to equivalent barrels of oil, divide the cubic feet of gas produced by 6,000.

(ii) Sum the daily production for each individual well at the well site to determine the total well site production and divide by the number of days in the month. This is the average daily total well site production for the month.

(iii) Use the result determined in paragraph (k)(1)(ii) of this section and average with the daily total well site production values determined for each of the preceding 11 months to calculate the rolling 12-month average of the total well site production.

(2) You must maintain records as specified in § 60.5420a(c)(15)(ii).

(3) You must submit compliance information in the initial and subsequent annual reports as specified in § 60.5420a(b)(7)(i)(C) and (b)(7)(iv).

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017; 85 FR 57071, Sept. 14, 2020; 85 FR 57445, Sept. 15, 2020; 89 FR 17040, Mar. 8, 2024]

§ 60.5411a What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing emissions from centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your centrifugal compressor wet seal degassing systems, reciprocating compressors, pneumatic pumps, and storage vessels.

(a) Closed vent system requirements for reciprocating compressors and centrifugal compressor wet seal degassing systems.

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the reciprocating compressor rod packing emissions collection system to a process. You must design the closed vent system to route all gases, vapors, and fumes emitted from the centrifugal compressor wet seal fluid degassing system to a process or a control device that meets the requirements specified in § 60.5412a(a) through (c).

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by § 60.5416a(b).

(3) You must meet the requirements specified in paragraphs (a)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

(i) Except as provided in paragraph (a)(3)(ii) of this section, you must comply with either paragraph (a)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in § 60.5416a(a)(4)(i) and sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420a(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (a)(3)(i) of this section.

(b) Cover requirements for storage vessels and centrifugal compressor wet seal fluid degassing systems.

(1) The cover and all openings on the cover (*e.g.*, access hatches, sampling ports, pressure relief devices and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (a) or (c), and (d), of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated and sealed under normal operating conditions, including such times when working, standing/breathing, and flash emissions may be generated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(c) Closed vent system requirements for storage vessel affected facilities using a control device or routing emissions to a process.

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel affected facility to a control device that meets the requirements specified in § 60.5412a(c) and (d), or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual, and auditory inspections or optical gas imaging inspections as specified in § 60.5416a(c).

(3) You must meet the requirements specified in paragraphs (c)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (c)(3)(ii) of this section, you must comply with either paragraph (c)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420a(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (c)(3)(i) of this section.

(d) Closed vent systems requirements for centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels using a control device or routing emissions to a process.

(1) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the affected facility are routed to the control device and that the control device is of sufficient design and capacity to accommodate all emissions from the affected facility, and have it certified by a qualified professional engineer or an in-house engineer with expertise on the design and operation of the closed vent system in accordance with paragraphs (d)(1)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of subpart OOOOa of 40 CFR part 60. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(ii) The assessment shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in paragraph (d)(1)(i) of this section.

(2) [Reserved]

(e) Closed vent system requirements for pneumatic pump affected facilities using a control device or routing emissions to a process.

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the pneumatic pump to a control device or a process.

(2) You must design and operate a closed vent system with no detectable emissions, as demonstrated by § 60.5416a(b), olfactory, visual, and auditory inspections or optical gas imaging inspections as specified in § 60.5416a(d).

(3) You must meet the requirements specified in paragraphs (e)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (e)(3)(ii) of this section, you must comply with either paragraph (e)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420a(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (e)(3)(i) of this section.

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017; 85 FR 57446, Sept. 15, 2020]

§ 60.5412a What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my centrifugal compressor, and storage vessel affected facilities?

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your centrifugal compressor affected facility, or storage vessel affected facility.

(a) Each control device used to meet the emission reduction standard in § 60.5380a(a)(1) for your centrifugal compressor affected facility must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a control device model tested under § 60.5413a(d), which meets the criteria in § 60.5413a(d)(11) and meet the continuous compliance requirements in § 60.5413a(e).

(1) Each combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section. If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(i) You must reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413a(b), with the exceptions noted in § 60.5413a(a).

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of § 60.5413a(b), with the exceptions noted in § 60.5413a(a).

(iii) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under § 60.5413a(b), that combustion zone temperature is an indicator of destruction efficiency.

(iv) You must introduce the vent stream with the primary fuel or use the vent stream as the primary fuel in a boiler or process heater.

(2) Each vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413a(b). As an alternative to the performance testing requirements in § 60.5413a(b), you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of § 60.5413a(c).

(3) You must design and operate a flare in accordance with the requirements of § 60.18(b), and you must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(b) You must operate each control device installed on your centrifugal compressor affected facility in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system affected facility as required under § 60.5380a(a)(1) through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of § 60.5417a(a) through (g), you must demonstrate compliance according to the requirements of § 60.5415a(b)(2), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) or (d)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) and (2) of this section.

(1) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to § 60.5413a(c)(2) or (3) or according to the design required in paragraph (d)(2) of this section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in § 60.5420a(c)(10) and (12).

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vi) of this section.

(i) Regenerate or reactivate the spent carbon in a unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a unit equipped with an operating organic air emission controls in accordance with an emissions standard for VOC under another subpart in 40 CFR part 63 or this part.

(iii) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(iv) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(v) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vi) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(d) Each control device used to meet the emission reduction standard in § 60.5395a(a)(2) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (4) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under § 60.5413a(d), which meets the criteria in § 60.5413a(d)(11) and meet the continuous compliance requirements in § 60.5413a(e).

(1) For each combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) you must meet the requirements in paragraphs (d)(1)(i) through (iv) of this section.

(i) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(ii) Install and operate a continuous burning pilot flame.

(iii) Operate the combustion control device with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22 of appendix A-7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A-7 of this part visual observation as described in this paragraph.

(iv) Each enclosed combustion control device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (d)(1)(iv)(A) through (D) of this section. If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(A) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413a(b).

(B) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of § 60.5413a(b).

(C) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under § 60.5413a(b), that combustion zone temperature is an indicator of destruction efficiency.

(D) You must introduce the vent stream with the primary fuel or use the vent stream as the primary fuel in a boiler or process heater.

(2) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(3) You must design and operate a flare in accordance with the requirements of § 60.18(b), and you must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(4) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57071, Sept. 14, 2020; 85 FR 57447, Sept. 15, 2020; 89 FR 17041, Mar. 8, 2024]

§ 60.5413a What are the performance testing procedures for control devices used to demonstrate compliance at my centrifugal compressor and storage vessel affected facilities?

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your centrifugal compressor affected facility or storage vessel affected facility. You must demonstrate that a control device achieves the performance requirements of § 60.5412a(a)(1) or (2) or (d)(1) or (2) using the performance test methods and procedures specified in this section. For condensers and carbon adsorbers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion control device performance tests conducted by the manufacturer applicable to storage vessel and centrifugal compressor affected facilities.

(a) ***Performance test exemptions.*** You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) A flare that is designed and operated in accordance with § 60.18(b). You must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H; you have submitted a Notification of Compliance under 40 CFR 63.1207(j) and comply with the requirements of 40 CFR part 63, subpart EEE; or you comply with 40 CFR part 63, subpart EEE and will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in § 60.5420(b)(9) for submitting the initial performance test report.

(5) A hazardous waste incinerator for which you have submitted a Notification of Compliance under 40 CFR 63.1207(j), or for which you will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in § 60.5420a(b)(9) for submitting the initial performance test report, and you comply with the requirements of 40 CFR part 63, subpart EEE.

(6) A performance test is waived in accordance with § 60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of § 60.5412a(a)(1) or (d)(1) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) ***Test methods and procedures.*** You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of § 60.5412a(a)(1) or (2) or (d)(1) or (2). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section. Each performance test must consist of a minimum of 3 test runs. Each run must be at least 1 hour long.

(1) You must use Method 1 or 1A of appendix A-1 of this part, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device and at the outlet of the final control device to determine compliance with a control device percent reduction requirement.

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with a TOC exhaust gas concentration limit.

(2) You must determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D of appendix A-2 of this part, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in § 60.5412a(a)(1)(i), (a)(2) or (d)(1)(iv)(A), you must use Method 25A of appendix A-7 of this part. You must use Method 4 of appendix A-3 of this part to convert the Method 25A results to a dry basis. You must use the procedures in paragraphs (b)(3)(i) through (iii) of this section to calculate percent reduction efficiency.

(i) You must compute the mass rate of TOC using the following equations:

$$E_i = K_2 C_i M_p Q_i$$
$$E_o = K_2 C_o M_p Q_o$$

Where:

E_i, E_o = Mass rate of TOC at the inlet and outlet of the control device, respectively, dry basis, kilograms per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 °Celsius.

C_i, C_o = Concentration of TOC, as propane, of the gas stream as measured by Method 25A at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_p = Molecular weight of propane, 44.1 gram/gram-mole.

Q_i, Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

(ii) You must calculate the percent reduction in TOC as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

Where:

R_{cd} = Control efficiency of control device, percent.

E_i, = Mass rate of TOC at the inlet to the control device as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

E_o = Mass rate of TOC at the outlet of the control device, as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

(iii) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC across the device by comparing the TOC in all combusted vent streams and primary and secondary fuels with the TOC exiting the device, respectively.

(4) You must use Method 25A of appendix A-7 to this part to measure TOC, as propane, to determine compliance with the TOC exhaust gas concentration limit specified in § 60.5412a(a)(1)(ii) or (d)(1)(iv)(B). If you are determining compliance with the TOC exhaust gas concentration limit specified in § 60.5412a(d)(1)(iv)(B), you may also use Method 18 of appendix A-6 to this part to measure methane and ethane, and you may subtract the measured concentration of methane and ethane from the Method 25A measurement to demonstrate compliance with the concentration limit. You must determine the concentration in parts per million by volume on a wet basis and correct it to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) If you use Method 18 to determine methane and ethane, you must take either an integrated sample or a minimum of four grab samples per hour. 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. You must determine the average methane and ethane concentration per run. The samples must be taken during the same time as the Method 25A sample.

(ii) If you are determining compliance with the TOC exhaust gas concentration limit specified in § 60.5412a(d)(1)(iv)(B), you may subtract the concentration of methane and ethane from the Method 25A TOC, as propane, concentration for each run.

(iii) You must correct the TOC concentration (minus methane and ethane, if applicable) to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B of appendix A-2 of this part, ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2m}} \right)$$

Where:

C_c = TOC concentration, as propane, corrected to 3 percent oxygen, parts per million by volume on a wet basis.

C_m = TOC concentration, as propane, (minus methane and ethane, if applicable), parts per million by volume on a wet basis.

$\%O_{2m}$ = Concentration of oxygen, percent by volume as measured, wet.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in § 60.5420a(b)(9).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in § 60.5420a(b)(9).

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section. For centrifugal compressor affected facilities, if you do not continuously monitor the gas flow rate in accordance with § 60.5417a(d)(1)(viii), then you must comply with the periodic performance testing requirements of paragraph (b)(5)(ii).

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in § 60.5412a(a)(1)(ii) or (d)(1)(iv)(B) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level. For centrifugal compressor affected facilities, you must establish a limit on temperature in accordance with § 60.5417a(f) and continuously monitor the temperature as required by § 60.5417a(d).

(c) ***Control device design analysis to meet the requirements of § 60.5412a(a)(2) or (d)(2).*** (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and must 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.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, 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 the carbon beds, design total regeneration stream 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 the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems shall incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

(d) ***Performance testing for combustion control devices—manufacturers' performance test.***

(1) This paragraph (d) applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three 1-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90-100 percent of maximum design rate (fixed rate).

(ii) 70-100-70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30-70-30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0-30-0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) and (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with Method 2A of appendix A-1 of this part (or other approved procedure) to measure inlet gas flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet flow rate must be determined using Method 2A of appendix A-1 of this part. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) and (ii) of this section.

(i) At the inlet gas sampling location, securely connect a fused silica-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of each test run, and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945-03 (incorporated by reference as specified in § 60.17).

(B) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945-03 (incorporated by reference as specified in § 60.17).

(C) Higher heating value using ASTM D3588-98 or ASTM D4891-89 (incorporated by reference as specified in § 60.17).

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) and (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using Method 1 of appendix A-1 of this part for determining flow measurement traverse point location, and Method 2 of appendix A-1 of this part for measuring duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the moisture test required by Method 4 of appendix A-3 of this part following the procedure specified in (d)(7)(i)(A) and (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC-TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) and (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC-TCD calibration procedure in Method 3C of appendix A-2 of this part must be modified by using EPA Alt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using Method 4 of appendix A-3 of this part. Traverse both ports with the sampling train required by Method 4 of appendix A-3 of this part during each test run. Ambient air must not be introduced into the integrated bag sample required by Method 3C of appendix A-2 of this part during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B of appendix A-2 of this part, equation 3B-1, or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17).

(8) Carbon monoxide must be determined using Method 10 of appendix A-4 of this part. Run the test simultaneously with Method 25A of appendix A-7 of this part using the same sampling points. An instrument range of 0-10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified by in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using Method 25A of appendix A-7 of this part, except that the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test run.

(ii) A valid test must consist of three Method 25A tests, each no less than 60 minutes in duration.

(iii) A 0-10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0-30 ppmvw (as propane) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—"EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," (incorporated by reference as specified in § 60.17).

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO_2, as measured by Method 3C of appendix A-2 of this part. You must use the following equation for this diluent concentration correction:

$$C_{corr} = C_{meas}\left(\frac{3}{CO_{2meas}}\right)$$

Where:
C_{meas} = The measured concentration of the pollutant.
CO_{2meas} = The measured concentration of the CO_2 diluent.
3 = The corrected reference concentration of CO_2 diluent.
C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using Method 22 of appendix A-7 of this part. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) ***Performance test criteria.***

(i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Results from Method 22 of appendix A-7 of this part determined under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average results from Method 25A of appendix A-7 of this part determined under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(D) Excess air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(ii) The manufacturer must determine a maximum inlet gas flow rate which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(11)(iii) of this section. The maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

(iii) A manufacturer must demonstrate a destruction efficiency of at least 95 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95 percent for THC, as propane, will meet the control requirement for 95 percent destruction of VOC and methane (if applicable) required under this subpart.

(12) The owner or operator of a combustion control device model tested under this paragraph (d)(12) must submit the information listed in paragraphs (d)(12)(i) through (vi) of this section for each test run in the test report required by this section in accordance with § 60.5420a(b)(10). Owners or operators who claim that any of the performance test information being submitted is confidential business information (CBI) must submit a complete file 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 Attn: CBI Document Control Officer; Office of Air Quality Planning and Standards (OAQPS), Room 521; 109 T.W. Alexander Drive; Research Triangle Park, NC 27711. The same file with the CBI omitted must be submitted to *Oil__and__Gas__PT@EPA.GOV.*

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess air range.

(G) Flame arrestor(s).

(H) Burner manifold.

(I) Pilot flame indicator.

(J) Pilot flame design fuel and calculated or measured fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) ***Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.*** This paragraph (e) applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance criteria in paragraph (d)(11) of this section by installing a device tested under paragraph (d) of this section, complying with the criteria specified in paragraphs (e)(1) through (8) of this section, maintaining the records specified in § 60.5420a(c)(2) or (c)(5)(vi) and submitting the report specified in § 60.5420a(b)(10).

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22 of appendix A-7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass a visual observation according to EPA Method 22 of appendix A-7 of this part as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via email to *Oil____and____Gas____PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/*.

(7) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(8) Operate each control device following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57071, Sept. 14, 2020; 85 FR 57447, Sept. 15, 2020; 89 FR 17041, Mar. 8, 2024]

§ 60.5415a How do I demonstrate continuous compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, and collection of fugitive emissions components at a compressor station affected facilities, equipment leaks at onshore natural gas processing plants and sweetening unit affected facilities?

(a) For each well affected facility, you must demonstrate continuous compliance by submitting the reports required by § 60.5420a(b)(1) and (2) and maintaining the records for each completion operation specified in § 60.5420a(c)(1).

(b) For each centrifugal compressor affected facility and each pneumatic pump affected facility, you must demonstrate continuous compliance according to paragraph (b)(3) of this section. For each centrifugal compressor affected facility, you also must demonstrate continuous compliance according to paragraphs (b)(1) and (2) of this section.

(1) You must reduce methane and VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of § 60.5412a(a) using the procedures specified in paragraphs (b)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in § 60.5412a(a)(2), you may demonstrate compliance according to paragraph (b)(2)(viii) of this section. You may switch between compliance with paragraphs (b)(2)(i) through (vii) of this section and compliance with paragraph (b)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of § 60.5417a(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with § 60.5417a(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (b)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (b)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in § 60.5413a(d), compliance with the operating parameter limit is achieved when the criteria in § 60.5413a(e) are met.

(iv) You must operate the continuous monitoring system required in § 60.5417a(a) at all times the affected source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of § 60.5412a(a)(1) and you demonstrate compliance using the test procedures specified in § 60.5413a(b), or you use a flare designed and operated in accordance with § 60.18(b), you must comply with paragraphs (b)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(C) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A-7 of this part visual observation as described in paragraph (b)(2)(vii)(B) of this section.

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in § 60.5412a(a)(2), you must demonstrate compliance using the procedures in paragraphs (b)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to § 60.5417a(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with § 60.5417a(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (b)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (b)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (b)(2)(viii)(D)(*1*) and (*2*) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (b)(2)(viii)(C) of this section.

(*1*) After the compliance dates specified in § 60.5370a(a), if you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation after the compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(*2*) After 120 days and no more than 364 days of operation after the compliance date specified in § 60.5370a(a), you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (b)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(3) You must submit the annual reports required by § 60.5420a(b)(1), (3), and (8) and maintain the records as specified in § 60.5420a(c)(2), (6) through (11), (16), and (17), as applicable.

(c) For each reciprocating compressor affected facility complying with § 60.5385a(a)(1) or (2), you must demonstrate continuous compliance according to paragraphs (c)(1) through (3) of this section. For each reciprocating compressor affected facility complying with § 60.5385a(a)(3), you must demonstrate continuous compliance according to paragraph (c)(4) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup, since August 2, 2016, or since the date of the most recent reciprocating compressor rod packing replacement, whichever is latest.

(2) You must submit the annual reports as required in § 60.5420a(b)(1) and (4) and maintain records as required in § 60.5420a(c)(3).

(3) You must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(4) You must operate the rod packing emissions collection system under negative pressure and continuously comply with the cover and closed vent requirements in § 60.5416a(a) and (b).

(d) For each pneumatic controller affected facility, you must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

(1) You must continuously operate the pneumatic controllers as required in § 60.5390a(a), (b), or (c).

(2) You must submit the annual reports as required in § 60.5420a(b)(1) and (5).

(3) You must maintain records as required in § 60.5420a(c)(4).

(e) You must demonstrate continuous compliance according to paragraph (e)(3) of this section for each storage vessel affected facility, for which you are using a control device or routing emissions to a process to meet the requirement of § 60.5395a(a)(2).

(1)-(2) [Reserved]

(3) For each storage vessel affected facility, you must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) You must reduce VOC emissions as specified in § 60.5395a(a)(2).

(ii) For each control device installed to meet the requirements of § 60.5395a(a)(2), you must demonstrate continuous compliance with the performance requirements of § 60.5412a(d) for each storage vessel affected facility using the procedure specified in paragraph (e)(3)(ii)(A) and either (e)(3)(ii)(B) or (e)(3)(ii)(C) of this section.

(A) You must comply with § 60.5416a(c) for each cover and closed vent system.

(B) You must comply with § 60.5417a(h) for each control device.

(C) Each closed vent system that routes emissions to a process must be operated as specified in § 60.5411a(c)(2) and (3).

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with methane and VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400a.

(g) For each sweetening unit affected facility, you must demonstrate continuous compliance with the standards for SO_2 specified in § 60.5405a(b) according to paragraphs (g)(1) and (2) of this section.

(1) The minimum required SO_2 emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406a(c)(1).

(h) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, you must demonstrate continuous compliance with the fugitive emission standards specified in § 60.5397a(a)(1) according to paragraphs (h)(1) through (4) of this section.

(1) You must conduct periodic monitoring surveys as required in § 60.5397a(g).

(2) You must repair each identified source of fugitive emissions as required in § 60.5397a(h).

(3) You must maintain records as specified in § 60.5420a(c)(15).

(4) You must submit annual reports for collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in § 60.5420a(b)(1) and (7).

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017; 85 FR 57071, Sept. 14, 2020; 85 FR 57447, Sept. 15, 2020; 89 FR 17041, Mar. 8, 2024]

§ 60.5416a What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my centrifugal compressor, reciprocating compressor, pneumatic pump, and storage vessel affected facilities?

For each closed vent system or cover at your centrifugal compressor, reciprocating compressor, pneumatic pump, and storage vessel affected facilities, you must comply with the applicable requirements of paragraphs (a) through (d) of this section.

(a) ***Inspections for closed vent systems and covers installed on each centrifugal compressor or reciprocating compressor affected facility.*** Except as provided in paragraphs (b)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) and (ii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(ii) Conduct annual inspections according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(3) For each cover, you must meet the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) You must initially conduct the inspections specified in paragraph (a)(3)(i) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (b)(11) and (12) of this section. You must maintain records of the inspection results as specified in § 60.5420a(c)(7).

(4) For each bypass device, except as provided for in § 60.5411a(a)(3)(ii), you must meet the requirements of paragraph (a)(4)(i) or (ii) of this section.

(i) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to § 60.5420a(c)(8).

(b) ***No detectable emissions test methods and procedures.*** If you are required to conduct an inspection of a closed vent system or cover at your centrifugal compressor or reciprocating compressor affected facility as specified in paragraph (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21 of appendix A-7 of this part.

(2) The detection instrument must meet the performance criteria of Method 21 of appendix A-7 of this part, except that the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 of appendix A-7 of this part.

(4) Calibration gases must be as specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 of appendix A-7 of this part.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (b)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 of appendix A-7 of this part, except the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (b)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (b)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (b)(7) of this section is less than 500 parts per million by volume.

(9) ***Repairs.*** In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (b)(9)(i) and (ii) of this section, except as provided in paragraph (b)(10) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) ***Delay of repair.*** Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) ***Unsafe to inspect requirements.*** You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (b)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1), (2), or (3) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) ***Difficult to inspect requirements.*** You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (b)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) ***Records.*** Records shall be maintained as specified in this section and in § 60.5420a(c)(9).

(c) ***Cover and closed vent system inspections for storage vessel affected facilities.*** If you install a control device or route emissions to a process, you must comply with the inspection and recordkeeping requirements for each closed vent system and cover as specified in paragraphs (c)(1) and (2) of this section. You must also comply with the requirements of paragraphs (c)(3) through (7) of this section.

(1) ***Closed vent system inspections.*** For each closed vent system, you must conduct an inspection as specified in paragraphs (c)(1)(i) through (iii) or paragraph (c)(1)(iv) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(ii) Conduct olfactory, visual, and auditory inspections at least once every calendar month for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(iv) Conduct optical gas imaging inspections for any visible emissions at the same frequency as the frequency for the collection of fugitive emissions components located at the same type of site, as specified in § 60.5397a(g)(1).

(2) ***Cover inspections.*** For each cover, you must conduct inspections as specified in paragraphs (c)(2)(i) through (iii) or paragraph (c)(2)(iv) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420a(c)(7).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(iv) Conduct optical gas imaging inspections for any visible emissions at the same frequency as the frequency for the collection of fugitive emissions components located at the same type of site, as specified in § 60.5397a(g)(1).

(3) For each bypass device, except as provided for in § 60.5411a(c)(3)(ii), you must meet the requirements of paragraphs (c)(3)(i) or (ii) of this section.

(i) You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, or initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to § 60.5420a(c)(8).

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections and records of each time the key is checked out, if applicable, according to § 60.5420a(c)(8).

(4) ***Repairs.*** In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (c)(4)(i) through (iii) of this section, except as provided in paragraph (c)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 30 calendar days after the leak is detected.

(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) ***Delay of repair.*** Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) ***Unsafe to inspect requirements.*** You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (c)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (c)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) ***Difficult to inspect requirements.*** You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (c)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(d) ***Closed vent system inspections for pneumatic pump affected facilities.*** If you install a control device or route emissions to a process, you must comply with the inspection and recordkeeping requirements for each closed vent system as specified in paragraph (d)(1) of this section. You must also comply with the requirements of paragraphs (c)(3) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection as specified in paragraphs (d)(1)(i) through (iii), paragraph (d)(1)(iv), or paragraph (d)(1)(v) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(ii) Conduct olfactory, visual, and auditory inspections at least once every calendar month for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(iv) Conduct optical gas imaging inspections for any visible emissions at the same frequency as the frequency for the collection of fugitive components located at the same type of site, as specified in § 60.5397a(g)(1).

(v) Conduct inspections as specified in paragraphs (a)(1) and (2) of this section.

(2) [Reserved]

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017; 85 FR 57448, Sept. 15, 2020]

§ 60.5417a What are the continuous control device monitoring requirements for my centrifugal compressor and storage vessel affected facilities?

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your storage vessel affected facility or centrifugal compressor affected facility.

(a) For each control device used to comply with the emission reduction standard for centrifugal compressor affected facilities in § 60.5380a(a)(1), you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with § 60.5412a(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section. If you install and operate an enclosed combustion device or control device which is not specifically listed in paragraph (d) of this section, you must demonstrate continuous compliance according to paragraphs (h)(1) through (4) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 60.5413a(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame. The heat sensing monitoring device is exempt from the calibration requirements of this section.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater.

(vii) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in § 60.5413a(c)(3). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under § 60.5413a(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section. If you comply with the periodic testing requirements of § 60.5413a(b)(5)(ii), you are not required to continuously monitor the gas flow rate under paragraph (d)(1)(viii)(A) of this section.

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better at the maximum expected flow rate. The flow rate at the inlet to the combustion device must not exceed the maximum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the control device.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. The monitor must meet the requirements of Performance Specification 8 or 9 of appendix B of this part. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(3) A continuous monitoring system that measures operating parameters other than those specified in paragraph (d)(1) or (2) of this section, upon approval of the Administrator as specified in § 60.13(i).

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate and data from the heat sensing devices that indicate the presence of a pilot flame. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 60.5412a(a)(1) or (2). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of § 60.5413a(b) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412a(a)(1) or (2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of § 60.5413a(c) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412a(a)(2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under § 60.5413a(d) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412a(a)(1), then your control device inlet gas flow rate must not exceed the maximum inlet gas flow rate determined by the manufacturer.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of § 60.5413a(b) to demonstrate that the condenser achieves the applicable performance requirements in § 60.5412a(a)(2), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of § 60.5413a(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in § 60.5412a(a)(2), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section or when the heat sensing device indicates that there is no pilot flame present.

(2) If you are subject to § 60.5412a(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 60.5415a(b)(2)(viii)(D) is less than 95.0 percent.

(3) If you are subject to § 60.5412a(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in § 60.5415a(b)(2)(viii)(D)(*1*) or (*2*) is less than 95.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraph (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to § 60.5411a(a)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to § 60.5411a(a)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under § 60.5413a(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) of this section are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under § 60.5413a(d).

(ii) Failure of the monthly visible emissions test conducted under § 60.5413a(e)(3) occurs.

(h) For each control device used to comply with the emission reduction standard in § 60.5395a(a)(2) for your storage vessel affected facility, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(4) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with § 60.5413a(d)(2) through (10), which meets the criteria in § 60.5413a(d)(11), the reporting requirement in § 60.5413a(d)(12), and meet the continuous compliance requirement in § 60.5413a(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (h)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22 of appendix A of this part. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

(iii) Conduct olfactory, visual and auditory inspections of all equipment associated with the combustion device to ensure system integrity.

(iv) For any absence of the pilot flame, or other indication of smoking or improper equipment operation (*e.g.,* visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (h)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified in § 60.5420a(c)(13).

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in § 60.5413a(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57449, Sept. 15, 2020]

§ 60.5420a What are my notification, reporting, and recordkeeping requirements?

(a) ***Notifications.*** You must submit the notifications according to paragraphs (a)(1) and (2) of this section if you own or operate one or more of the affected facilities specified in § 60.5365a that was constructed, modified, or reconstructed during the reporting period.

(1) If you own or operate an affected facility that is the group of all equipment within a process unit at an onshore natural gas processing plant, or a sweetening unit, you must submit the notifications required in §§ 60.7(a)(1), (3), and (4) and 60.15(d). If you own or operate a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, or collection of fugitive emissions components at a compressor station, you are not required to submit the notifications required in §§ 60.7(a)(1), (3), and (4) and 60.15(d).

(2)

(i) If you own or operate a well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the United States Well Number; the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

(ii) If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

(3) An owner or operator electing to comply with the provisions of § 60.5399a shall notify the Administrator of the alternative fugitive emissions standard selected within the annual report, as specified in paragraph (b)(7) of this section.

(b) ***Reporting requirements.*** You must submit annual reports containing the information specified in paragraphs (b)(1) through (8) and (12) of this section and performance test reports as specified in paragraph (b)(9) or (10) of this section, if applicable. You must submit annual reports following the procedure specified in paragraph (b)(11) of this section. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to § 60.5410a. Subsequent annual reports are due no later than same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (8) and (12) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section is required for all reports.

(i) The company name, facility site name associated with the affected facility, U.S. Well ID or U.S. Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(2) For each well affected facility that is subject to § 60.5375a(a) or (f), the records of each well completion operation conducted during the reporting period, including the information specified in paragraphs (b)(2)(i) through (xiv) of this section, if applicable. In lieu of submitting the records specified in paragraphs (b)(2)(i) through (xiv) of this section, the owner or operator may submit a list of each well completion with hydraulic fracturing completed during the reporting period, and the digital photograph required by paragraph (c)(1)(v) of this section for each well completion. For each well affected facility that routes flowback entirely through one or more production separators, only the records specified in paragraphs (b)(2)(i) through (iv) and (vi) of this section are required to be reported. For periods where salable gas is unable to be separated, the records specified in paragraphs (b)(2)(iv) and (viii) through (xii) of this section must also be reported, as applicable. For each well affected facility that is subject to § 60.5375a(g), the record specified in paragraph (b)(2)(xv) of this section is required to be reported.

(i) Well Completion ID.

(ii) Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983.

(iii) U.S. Well ID.

(iv) The date and time of the onset of flowback following hydraulic fracturing or refracturing or identification that the well immediately starts production.

(v) The date and time of each attempt to direct flowback to a separator as required in § 60.5375a(a)(1)(ii).

(vi) The date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production.

(vii) The duration (in hours) of flowback.

(viii) The duration (in hours) of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve).

(ix) The duration (in hours) of combustion.

(x) The duration (in hours) of venting.

(xi) The specific reasons for venting in lieu of capture or combustion.

(xii) For any deviations recorded as specified in paragraph (c)(1)(ii) of this section, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(xiii) For each well affected facility subject to § 60.5375a(f), a record of the well type (*i.e.,* wildcat well, delineation well, or low pressure well (as defined § 60.5430a)) and supporting inputs and calculations, if applicable.

(xiv) For each well affected facility for which you claim an exception under § 60.5375a(a)(3), the specific exception claimed and reasons why the well meets the claimed exception.

(xv) For each well affected facility with less than 300 scf of gas per stock tank barrel of oil produced, the supporting analysis that was performed in order the make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field.

(3) For each centrifugal compressor affected facility, the information specified in paragraphs (b)(3)(i) through (v) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified, or reconstructed during the reporting period.

(ii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(2) of this section, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(iii) If required to comply with § 60.5380a(a)(2), the information in paragraphs (b)(3)(iii)(A) through (C) of this section.

(A) Dates of each inspection required under § 60.5416a(a) and (b);

(B) Each defect or leak identified during each inspection, date of repair or the date of anticipated repair if the repair is delayed; and

(C) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416a(a)(4).

(iv) If complying with § 60.5380a(a)(1) with a control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and (e), the information in paragraphs (b)(3)(iv)(A) through (D) of this section.

(A) Identification of the compressor with the control device.

(B) Make, model, and date of purchase of the control device.

(C) For each instance where the inlet gas flow rate exceeds the manufacturer's listed maximum gas flow rate, where there is no indication of the presence of a pilot flame, or where visible emissions exceeded 1 minute in any 15-minute period, include the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(D) For each visible emissions test following return to operation from a maintenance or repair activity, the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present.

(v) If complying with § 60.5380a(a)(1) with a control device not tested under § 60.5413a(d), identification of the compressor with the tested control device, the date the performance test was conducted, and pollutant(s) tested. Submit the performance test report following the procedures specified in paragraph (b)(9) of this section.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) through (iii) of this section.

(i) The cumulative number of hours of operation or the number of months since initial startup, since August 2, 2016, or since the previous reciprocating compressor rod packing replacement, whichever is latest. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) If applicable, for each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(3)(iii) of this section, the date and time the deviation began, duration of the deviation and a description of the deviation.

(iii) If required to comply with § 60.5385a(a)(3), the information in paragraphs (b)(4)(iii)(A) through (C) of this section.

(A) Dates of each inspection required under § 60.5416a(a) and (b);

(B) Each defect or leak identified during each inspection, and date of repair or date of anticipated repair if repair is delayed; and

(C) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416a(a)(4).

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (iii) of this section.

(i) An identification of each pneumatic controller constructed, modified, or reconstructed during the reporting period, including the month and year of installation, reconstruction or modification and identification information that allows traceability to the records required in paragraph (c)(4)(iii) or (iv) of this section.

(ii) If applicable, reason why the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required.

(iii) For each instance where the pneumatic controller was not operated in compliance with the requirements specified in § 60.5390a, a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (ix) of this section.

(i) An identification, including the location, of each storage vessel affected facility for which construction, modification, or reconstruction commenced during the reporting period. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the VOC emission rate determination according to § 60.5365a(e)(1) for each storage vessel that became an affected facility during the reporting period or is returned to service during the reporting period.

(iii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(5) of this section, the date and time the deviation began, duration of the deviation and a description of the deviation.

(iv) A statement that you have met the requirements specified in § 60.5410a(h)(2) and (3).

(v) For each storage vessel constructed, modified, reconstructed, or returned to service during the reporting period complying with § 60.5395a(a)(2) with a control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and (e), the information in paragraphs (b)(6)(v)(A) through (D) of this section.

(A) Identification of the storage vessel with the control device.

(B) Make, model, and date of purchase of the control device.

(C) For each instance where the inlet gas flow rate exceeds the manufacturer's listed maximum gas flow rate, where there is no indication of the presence of a pilot flame, or where visible emissions exceeded 1 minute in any 15-minute period, include the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(D) For each visible emissions test following return to operation from a maintenance or repair activity, the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present.

(vi) If complying with § 60.5395a(a)(2) with a control device not tested under § 60.5413a(d), identification of the storage vessel with the tested control device, the date the performance test was conducted, and pollutant(s) tested. Submit the performance test report following the procedures specified in paragraph (b)(9) of this section.

(vii) If required to comply with § 60.5395a(b)(1), the information in paragraphs (b)(6)(vii)(A) through (C) of this section.

(A) Dates of each inspection required under § 60.5416a(c);

(B) Each defect or leak identified during each inspection, and date of repair or date of anticipated repair if repair is delayed; and

(C) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416a(c)(3).

(viii) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in § 60.5395a(c)(1)(ii), including the date the storage vessel affected facility was removed from service.

(ix) You must identify each storage vessel affected facility returned to service during the reporting period as specified in § 60.5395a(c)(3), including the date the storage vessel affected facility was returned to service.

(7) For the collection of fugitive emissions components at each well site and the collection of fugitive emissions components at each compressor station, report the information specified in paragraphs (b)(7)(i) through (iii) of this section, as applicable.

(i)

(A) Designation of the type of site (*i.e.,* well site or compressor station) at which the collection of fugitive emissions components is located.

(B) For each collection of fugitive emissions components at a well site that became an affected facility during the reporting period, you must include the date of the startup of production or the date of the first day of production after modification. For each collection of fugitive emissions components at a compressor station that became an affected facility during the reporting period, you must include the date of startup or the date of modification.

(C) [Reserved]

(D) For each collection of fugitive emissions components at a well site where during the reporting period you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, you must include the date of the change to status as a wellhead only well site.

(E) For each collection of fugitive emissions components at a well site where you previously reported under paragraph (b)(7)(i)(C) of this section the removal of all major production and processing equipment and during the reporting period major production and processing equipment is added back to the well site, the date that the first piece of major production and processing equipment is added back to the well site.

(ii) For each fugitive emissions monitoring survey performed during the annual reporting period, the information specified in paragraphs (b)(7)(ii)(A) through (G) of this section.

(A) Date of the survey.

(B) Monitoring instrument used.

(C) Any deviations from the monitoring plan elements under § 60.5397a(c)(1), (2), and (7) and (c)(8)(i) or a statement that there were no deviations from these elements of the monitoring plan.

(D) Number and type of components for which fugitive emissions were detected.

(E) Number and type of fugitive emissions components that were not repaired as required in § 60.5397a(h).

(F) Number and type of fugitive emission components (including designation as difficult-to-monitor or unsafe-to-monitor, if applicable) on delay of repair and explanation for each delay of repair.

(G) Date of planned shutdown(s) that occurred during the reporting period if there are any components that have been placed on delay of repair.

(iii) For each collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station complying with an alternative fugitive emissions standard under § 60.5399a, in lieu of the information specified in paragraphs (b)(7)(i) and (ii) of this section, you must provide the information specified in paragraphs (b)(7)(iii)(A) through (C) of this section.

(A) The alternative standard with which you are complying.

(B) The site-specific reports specified by the specific alternative fugitive emissions standard, submitted in the format in which they were submitted to the state, local, or tribal authority. If the report is in hard copy, you must scan the document and submit it as an electronic attachment to the annual report required in paragraph (b) of this section.

(C) If the report specified by the specific alternative fugitive emissions standard is not site-specific, you must submit the information specified in paragraphs (b)(7)(i) and (ii) of this section for each individual site complying with the alternative standard.

(iv) If you comply with the alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (b)(7)(ii) of this section, you must provide the information specified in § 60.5424b.

(8) For each pneumatic pump affected facility, the information specified in paragraphs (b)(8)(i) through (iv) of this section.

(i) For each pneumatic pump that is constructed, modified or reconstructed during the reporting period, you must provide certification that the pneumatic pump meets one of the conditions described in paragraph (b)(8)(i)(A), (B), or (C) of this section.

(A) No control device or process is available on site.

(B) A control device or process is available on site and the owner or operator has determined in accordance with § 60.5393a(b)(5) that it is technically infeasible to capture and route the emissions to the control device or process.

(C) Emissions from the pneumatic pump are routed to a control device or process. If the control device is designed to achieve less than 95 percent emissions reduction, specify the percent emissions reductions the control device is designed to achieve.

(ii) For any pneumatic pump affected facility which has been previously reported as required under paragraph (b)(8)(i) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the pneumatic pump affected facility and the date it was previously reported and a certification that the pneumatic pump meets one of the conditions described in paragraph (b)(8)(ii)(A), (B), (C), or (D) of this section.

(A) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(8)(i)(C) of this section.

(B) A control device has been added to the location and the pneumatic pump affected facility now reports according to paragraph (b)(8)(i)(B) of this section.

(C) A control device or process has been removed from the location or otherwise is no longer available and the pneumatic pump affected facility now report according to paragraph (b)(8)(i)(A) of this section.

(D) A control device or process has been removed from the location or is otherwise no longer available and the owner or operator has determined in accordance with § 60.5393a(b)(5) through an engineering evaluation that it is technically infeasible to capture and route the emissions to another control device or process.

(iii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(16)(ii) of this section, the date and time the deviation began, duration of the deviation, and a description of the deviation.

(iv) If required to comply with § 60.5393a(b), the information in paragraphs (b)(8)(iv)(A) through (C) of this section.

(A) Dates of each inspection required under § 60.5416a(d);

(B) Each defect or leak identified during each inspection, and date of repair or date of anticipated repair if repair is delayed; and

(C) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416a(c)(3).

(9) Within 60 days after the date of completing each performance test (see § 60.8) required by this subpart, except testing conducted by the manufacturer as specified in § 60.5413a(d), you must submit the results of the performance test following the procedure specified in either paragraph (b)(9)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test, you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), except as outlined in this paragraph (b)(9)(i). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. 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). Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim, 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, to the EPA following the procedures in paragraphs (b)(9)(i)(A) and (B) 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. The same ERT or alternate file submitted to the CBI office with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (b)(9)(i).

(A) 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. ERT files should 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.

(B) 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 Leader, 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.

(ii) For 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, you must submit the results of the performance test to the Administrator at the appropriate address listed in § 60.4.

(10) For combustion control devices tested by the manufacturer in accordance with § 60.5413a(d), an electronic copy of the performance test results required by § 60.5413a(d) shall be submitted via email to *Oil__and__Gas__PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following website: *epa.gov/airquality/oilandgas/*.

(11) You must submit reports to the EPA via CEDRI, except as outlined in this paragraph (b)(11). CEDRI can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). You must use the appropriate electronic report template on the CEDRI website for this subpart (*https://www.epa.gov/electronic-reporting-air-emissions/cedri/*). If the reporting form specific to this subpart is not available on the CEDRI website at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 60.4. Once the form has been available in CEDRI for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The date reporting forms 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 reports must be submitted by the deadlines specified in this subpart, regardless of the method in which the reports are submitted. 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 in the report, submit a complete file using the appropriate electronic report template on the CEDRI website, including information claimed to be CBI, to the EPA following the procedures in paragraphs (b)(11)(i) and (ii) 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. Submit the same file submitted to the CBI office with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (b)(11).

(i) 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. Files should be flagged to the attention of the Oil and Natural Gas 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.

(ii) 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 Oil and Natural Gas 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.

(12) You must submit the certification signed by the qualified professional engineer or in-house engineer according to § 60.5411a(d) for each closed vent system routing to a control device or process.

(13) 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 the reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (b)(13)(i) through (vii) of this section.

(i) 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.

(ii) The outage must have occurred within the period of time beginning 5 business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) 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 caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the EPA system outage;

(C) Measures taken or to be taken to minimize the delay in reporting; and

(D) 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.

(vi) 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.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(14) If you are required to electronically submit a report through CEDRI in the EPA's CDX, the owner or operator may assert a claim of force majeure for failure to timely comply with the reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (b)(14)(i) through (v) of this section.

(i) 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 5 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).

(ii) 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 caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) Measures taken or to be taken to minimize the delay in reporting; and

(D) 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.

(iv) 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.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

(c) ***Recordkeeping requirements.*** You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (18) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained by this subpart that are submitted electronically via the EPA's CDX may be maintained in electronic format.

(1) The records for each well affected facility as specified in paragraphs (c)(1)(i) through (vii) of this section, as applicable. For each well affected facility for which you make a claim that the well affected facility is not subject to the requirements for well completions pursuant to § 60.5375a(g), you must maintain the record in paragraph (c)(1)(vi) of this section, only. For each well affected facility that routes flowback entirely through one or more production separators that are designed to accommodate flowback, only records of the United States Well Number, the latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983, the Well Completion ID, and the date and time of startup of production are required. For periods where salable gas is unable to be separated, records of the date and time of onset of flowback, the duration and disposition of recovery, the duration of combustion and venting (if applicable), reasons for venting (if applicable), and deviations are required.

(i) Records identifying each well completion operation for each well affected facility.

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375a, including the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(iii) You must maintain the records specified in paragraphs (c)(1)(iii)(A) through (C) of this section.

(A) For each well affected facility required to comply with the requirements of § 60.5375a(a), you must record: The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in § 60.5375a(a)(1)(ii); the date and time of each occurrence of returning to the initial flowback stage under § 60.5375a(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours. In addition, for wells where it is technically infeasible to route the recovered gas as specified in § 60.5375a(a)(1)(ii), you must record the reasons for the claim of technical infeasibility with respect to all four options provided in § 60.5375a(a)(1)(ii).

(B) For each well affected facility required to comply with the requirements of § 60.5375a(f), you must record: Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours.

(C) For each well affected facility for which you make a claim that it meets the criteria of § 60.5375a(a)(1)(iii)(A), you must maintain the following:

(*1*) The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours.

(*2*) If applicable, records that the conditions of § 60.5375a(a)(1)(iii)(A) are no longer met and that the well completion operation has been stopped and a separator installed. The records shall include the date and time the well completion operation was stopped and the date and time the separator was installed.

(*3*) A record of the claim signed by the certifying official that no liquids collection is at the well site. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(iv) For each well affected facility for which you claim an exception under § 60.5375a(a)(3), you must record: The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each well affected facility required to comply with both § 60.5375a(a)(1) and (3), if you are using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, you must retain the records of the digital photograph as specified in § 60.5410a(a)(4).

(vi) For each well affected facility for which you make a claim that the well affected facility is not subject to the well completion standards according to § 60.5375a(g), you must maintain:

(A) A record of the analysis that was performed in order the make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field;

(B) the latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number;

(C) A record of the claim signed by the certifying official. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(vii) For each well affected facility subject to § 60.5375a(f), a record of the well type (*i.e.,* wildcat well, delineation well, or low pressure well (as defined § 60.5430a)) and supporting inputs and calculations, if applicable.

(2) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in § 60.5380a, including a description of each deviation, the date and time each deviation began and the duration of each deviation. Except as specified in paragraph (c)(2)(viii) of this section, you must maintain the records in paragraphs (c)(2)(i) through (vii) of this section for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and (e) and used to comply with § 60.5380a(a)(1) for each centrifugal compressor.

(i) Make, model, and serial number of purchased device.

(ii) Date of purchase.

(iii) Copy of purchase order.

(iv) Location of the centrifugal compressor and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) Inlet gas flow rate.

(vi) Records of continuous compliance requirements in § 60.5413a(e) as specified in paragraphs (c)(2)(vi)(A) through (E) of this section.

(A) Records that the pilot flame is present at all times of operation.

(B) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15-minute period.

(C) Records of the maintenance and repair log.

(D) Records of the visible emissions test following return to operation from a maintenance or repair activity, including the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present.

(E) Records of the manufacturer's written operating instructions, procedures, and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(vii) Records of deviations for instances where the inlet gas flow rate exceeds the manufacturer's listed maximum gas flow rate, where there is no indication of the presence of a pilot flame, or where visible emissions exceeded 1 minute in any 15-minute period, including a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(viii) As an alternative to the requirements of paragraph (c)(2)(iv) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the centrifugal compressor and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the centrifugal compressor and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(3) For each reciprocating compressor affected facility, you must maintain the records in paragraphs (c)(3)(i) through (iii) of this section.

(i) Records of the cumulative number of hours of operation or number of months since initial startup, since August 2, 2016, or since the previous replacement of the reciprocating compressor rod packing, whichever is latest. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in § 60.5385a(a)(3).

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in § 60.5385a, including the date and time the deviation began, duration of the deviation, and a description of the deviation.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (v) of this section, as applicable.

(i) Records of the month and year of installation, reconstruction, or modification, location in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983, identification information that allows traceability to the records required in paragraph (c)(4)(iii) or (iv) of this section and manufacturer specifications for each pneumatic controller constructed, modified, or reconstructed.

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.

(iii) If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.

(iv) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(v) For each instance where the pneumatic controller was not operated in compliance with the requirements specified in § 60.5390a, a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (vii) of this section.

(i) If required to reduce emissions by complying with § 60.5395a(a)(2), the records specified in §§ 60.5420a(c)(6) through (8) and 60.5416a(c)(6)(ii) and (c)(7)(ii). You must maintain the records in paragraph (c)(5)(vi) of this section for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and (e) and used to comply with § 60.5395a(a)(2) for each storage vessel.

(ii) Records of each VOC emissions determination for each storage vessel affected facility made under § 60.5365a(e) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) For each instance where the storage vessel was not operated in compliance with the requirements specified in §§ 60.5395a, 60.5411a, 60.5412a, and 60.5413a, as applicable, a description of the deviation, the date and time each deviation began, and the duration of the deviation.

(iv) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships), records indicating the number of consecutive days that the vessel is located at a site in the crude oil and natural gas production segment, natural gas processing segment, or natural gas transmission and storage segment. If a storage vessel is removed from a site and, within 30 days, is either returned to the site or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(v) You must maintain records of the identification and location in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983 of each storage vessel affected facility.

(vi) Except as specified in paragraph (c)(5)(vi)(G) of this section, you must maintain the records specified in paragraphs (c)(5)(vi)(A) through (H) of this section for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and (e) and used to comply with § 60.5395a(a)(2) for each storage vessel.

(A) Make, model, and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in § 60.5413a(e) as specified in paragraphs (c)(5)(vi)(F)(*1*) through (*5*) of this section.

(*1*) Records that the pilot flame is present at all times of operation.

(*2*) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15-minute period.

(*3*) Records of the maintenance and repair log.

(*4*) Records of the visible emissions test following return to operation from a maintenance or repair activity, including the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present.

(*5*) Records of the manufacturer's written operating instructions, procedures, and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(G) Records of deviations for instances where the inlet gas flow rate exceeds the manufacturer's listed maximum gas flow rate, where there is no indication of the presence of a pilot flame, or where visible emissions exceeded 1 minute in any 15-minute period, including a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(H) As an alternative to the requirements of paragraph (c)(5)(vi)(D) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the storage vessel and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(vii) Records of the date that each storage vessel affected facility is removed from service and returned to service, as applicable.

(6) Records of each closed vent system inspection required under § 60.5416a(a)(1) and (2) and (b) for centrifugal compressors and reciprocating compressors, § 60.5416a(c)(1) for storage vessels, or § 60.5416a(e) for pneumatic pumps as required in paragraphs (c)(6)(i) through (iii) of this section.

(i) A record of each closed vent system inspection or no detectable emissions monitoring survey. You must include an identification number for each closed vent system (or other unique identification description selected by you) and the date of the inspection.

(ii) For each defect or leak detected during inspections required by § 60.5416a(a)(1) and (2), (b), (c)(1), or (d), you must record the location of the defect or leak, a description of the defect or the maximum concentration reading obtained if using Method 21 of appendix A-7 of this part, the date of detection, and the date the repair to correct the defect or leak is completed.

(iii) If repair of the defect is delayed as described in § 60.5416a(b)(10), you must record the reason for the delay and the date you expect to complete the repair.

(7) A record of each cover inspection required under § 60.5416a(a)(3) for centrifugal or reciprocating compressors or § 60.5416a(c)(2) for storage vessels as required in paragraphs (c)(7)(i) through (iii) of this section.

(i) A record of each cover inspection. You must include an identification number for each cover (or other unique identification description selected by you) and the date of the inspection.

(ii) For each defect detected during inspections required by § 60.5416a(a)(3) or (c)(2), you must record the location of the defect, a description of the defect, the date of detection, the corrective action taken the repair the defect, and the date the repair to correct the defect is completed.

(iii) If repair of the defect is delayed as described in § 60.5416a(b)(10) or (c)(5), you must record the reason for the delay and the date you expect to complete the repair.

(8) If you are subject to the bypass requirements of § 60.5416a(a)(4) for centrifugal compressors or reciprocating compressors, or § 60.5416a(c)(3) for storage vessels or pneumatic pumps, you must prepare and maintain a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.

(9) [Reserved]

(10) For each centrifugal compressor or pneumatic pump affected facility, records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5413a(c)(2) or (3)) and records of each carbon replacement as specified in § 60.5412a(c)(1).

(11) For each centrifugal compressor affected facility subject to the control device requirements of § 60.5412a(a), (b), and (c), records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(12) For each carbon adsorber installed on storage vessel affected facilities, records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5412a(d)(2)) and records of each carbon replacement as specified in § 60.5412a(c)(1).

(13) For each storage vessel affected facility subject to the control device requirements of § 60.5412a(c) and (d), you must maintain records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in § 60.5417a(h)(3). You must maintain records of EPA Method 22 of appendix A-7 of this part, section 11 results, which include: Company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in EPA Method 22 of appendix A-7 of this part. Manufacturer's operating instructions, procedures and maintenance schedule must be available for inspection.

(14) A log of records as specified in § 60.5412a(d)(1)(iii), for all inspection, repair, and maintenance activities for each control device failing the visible emissions test.

(15) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, maintain the records identified in paragraphs (c)(15)(i) through (viii) of this section.

(i) The date of the startup of production or the date of the first day of production after modification for each collection of fugitive emissions components at a well site and the date of startup or the date of modification for each collection of fugitive emissions components at a compressor station.

(ii)-(iv) [Reserved]

(v) For each collection of fugitive emissions components at a well site where you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, record the date the well site completes the removal of all major production and processing equipment from the well site, and, if the well site is still producing, record the well ID or separate tank battery ID receiving the production from the well site. If major production and processing equipment is subsequently added back to the well site, record the date that the first piece of major production and processing equipment is added back to the well site.

(vi) The fugitive emissions monitoring plan as required in § 60.5397a(b), (c), and (d).

(vii) The records of each monitoring survey as specified in paragraphs (c)(15)(vii)(A) through (I) of this section.

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s), training, and experience of the operator(s) performing the survey.

(D) Monitoring instrument used.

(E) Fugitive emissions component identification when Method 21 of appendix A-7 of this part is used to perform the monitoring survey.

(F) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey. For compressor stations, operating mode of each compressor (*i.e.,* operating, standby pressurized, and not operating-depressurized modes) at the station at the time of the survey.

(G) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(H) Records of calibrations for the instrument used during the monitoring survey.

(I) Documentation of each fugitive emission detected during the monitoring survey, including the information specified in paragraphs (c)(15)(vii)(I)(*1*) through (*9*) of this section.

(*1*) Location of each fugitive emission identified.

(*2*) Type of fugitive emissions component, including designation as difficult-to-monitor or unsafe-to-monitor, if applicable.

(*3*) If Method 21 of appendix A-7 of this part is used for detection, record the component ID and instrument reading.

(*4*) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph or video must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (*e.g.,* the latitude and longitude of the component or by other descriptive landmarks visible in the picture). The digital photograph or identification (*e.g.,* tag) may be removed after the repair is completed, including verification of repair with the resurvey.

(*5*) The date of first attempt at repair of the fugitive emissions component(s).

(*6*) The date of successful repair of the fugitive emissions component, including the resurvey to verify repair and instrument used for the resurvey.

(*7*) Identification of each fugitive emission component placed on delay of repair and explanation for each delay of repair

(*8*) For each fugitive emission component placed on delay of repair for reason of replacement component unavailability, the operator must document: the date the component was added to the delay of repair list, the date the replacement fugitive component or part thereof was ordered, the anticipated component delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the component.

(*9*) Date of planned shutdowns that occur while there are any components that have been placed on delay of repair.

(viii) For each collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station complying with an alternative means of emissions limitation under § 60.5399a, you must maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

(ix) If you comply with the alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (c)(15)(vi) through (vii) of this section, you must maintain the records specified in § 60.5424b.

(16) For each pneumatic pump affected facility, you must maintain the records identified in paragraphs (c)(16)(i) through (v) of this section.

(i) Records of the date, location, and manufacturer specifications for each pneumatic pump constructed, modified, or reconstructed.

(ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in § 60.5393a, including the date and time the deviation began, duration of the deviation, and a description of the deviation.

(iii) Records on the control device used for control of emissions from a pneumatic pump including the installation date, and manufacturer's specifications. If the control device is designed to achieve less than 95-percent emission reduction, maintain records of the design evaluation or manufacturer's specifications which indicate the percentage reduction the control device is designed to achieve.

(iv) Records substantiating a claim according to § 60.5393a(b)(5) that it is technically infeasible to capture and route emissions from a pneumatic pump to a control device or process; including the certification according to § 60.5393a(b)(5)(ii) and the records of the engineering assessment of technical infeasibility performed according to § 60.5393a(b)(5)(iii).

(v) You must retain copies of all certifications, engineering assessments, and related records for a period of five years and make them available if directed by the implementing agency.

(17) For each closed vent system routing to a control device or process, the records of the assessment conducted according to § 60.5411a(d):

(i) A copy of the assessment conducted according to § 60.5411a(d)(1);

(ii) A copy of the certification according to § 60.5411a(d)(1)(i); and

(iii) The owner or operator shall retain copies of all certifications, assessments, and any related records for a period of 5 years, and make them available if directed by the delegated authority.

(18) A copy of each performance test submitted under paragraph (b)(9) of this section.

[85 FR 57449, Sept. 15, 2020, as amended at 89 FR 17041, Mar. 8, 2024]

§ 60.5421a What are my additional recordkeeping requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of § 60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of § 60.5401a(b)(1).

(1) When each leak is detected as specified in § 60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in § 60.5401a(b)(2), the information specified in paragraphs (b)(2)(i) through (x) of this section must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) "Above 500 ppm" if the maximum instrument reading measured by the methods specified in § 60.5400a(d) after each repair attempt is 500 ppm or greater.

(v) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of § 60.482-4a(a). The designation of equipment subject to the provisions of § 60.482-4a(a) must be signed by the owner or operator.

§ 60.5422a What are my additional reporting requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of § 60.487a(a), (b)(1) through (3) and (5), and (c)(2)(i) through (iv) and (vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI website (*https://www3.epa.gov/ttn/chief/cedri/*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in § 60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in § 60.487a(b)(1) through (3) and (5): Number of pressure relief devices subject to the requirements of § 60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of § 60.482-4a(a) and those pressure relief devices complying with § 60.482-4a(c).

(c) An owner or operator must include the information specified in paragraphs (c)(1) and (2) of this section in all semiannual reports in addition to the information required in § 60.487a(c)(2)(i) through (iv) and (vii) through (viii):

(1) Number of pressure relief devices for which leaks were detected as required in § 60.5401a(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in § 60.5401a(b)(3).

[81 FR 35898, June 3, 2016, as amended at 85 FR 57457, Sept. 15, 2020]

§ 60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities?

(a) You must retain records of the calculations and measurements required in §§ 60.5405a(a) and (b) and 60.5407a(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under § 60.7(f) of the General Provisions.

(b) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. The procedures for submitting annual reports are located in § 60.5420a(b). For the purpose of these reports, excess emissions are defined as specified in paragraphs (b)(1) and (2) of this section. The report must contain the information specified in paragraph (b)(3) of this section.

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of § 60.5407a(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of § 60.5407a(b)(3). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(3) For each period of excess emissions during the reporting period, include the following information in your report:

(i) The date and time of commencement and completion of each period of excess emissions;

(ii) The required minimum efficiency (Z) and the actual average sulfur emissions reduction (R) for periods defined in paragraph (b)(1) of this section; and

(iii) The appropriate operating temperature and the actual average temperature of the gases leaving the combustion zone for periods defined in paragraph (b)(2) of this section.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less than 2 LT/D of H2S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H_2S expressed as sulfur.

(d) If you elect to comply with § 60.5407a(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H2S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state. Electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph do not relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57458, Sept. 15, 2020]

§ 60.5425a What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

§ 60.5430a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Artificial lift equipment means mechanical pumps including, but not limited to, rod pumps and electric submersible pumps used to flowback fluids from a well.

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(1) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(i) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation: $A = Y \times (B \div 100)$;

(ii) The percent Y is determined from the following equation: Y = (CPI of date of construction/most recently available CPI of date of project), where the “CPI-U, U.S. city average, all items” must be used for each CPI value; and

(iii) The applicable basic annual asset guideline repair allowance, B, is 4.5.

(2) [Reserved]

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities with an affected facility subject to this subpart and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including but not limited to general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the CAA or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under this part.

Coil tubing cleanout means the process where an operator runs a string of coil tubing to the packed proppant within a well and jets the well to dislodge the proppant and provide sufficient lift energy to flow it to the surface. Coil tubing cleanout includes mechanical methods to remove solids and/or debris from a wellbore.

Collection system means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a compressor station for purposes of § 60.5397a.

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

Continuous bleed means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

Crude oil and natural gas source category means:

(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and

(2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.

Custody meter means the meter where natural gas or hydrocarbon liquids are measured for sales, transfers, and/or royalty determination.

Custody meter assembly means an assembly of fugitive emissions components, including the custody meter, valves, flanges, and connectors necessary for the proper operation of the custody meter.

Custody transfer means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

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

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(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 limit, 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.

Equipment, as used in the standards and requirements in this subpart relative to the equipment leaks of GHG (in the form of methane) VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

First attempt at repair means, for the purposes of fugitive emissions components, an action taken for the purpose of stopping or reducing fugitive emissions to the atmosphere. First attempts at repair include, but are not limited to, the following practices where practicable and appropriate: Tightening bonnet bolts; replacing bonnet bolts; tightening packing gland nuts; or injecting lubricant into lubricated packing.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Flowback means the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage. Screenouts, coil tubing cleanouts, and plug drill-outs are not considered part of the flowback process.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to § 60.5411 or § 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to § 60.5395 or § 60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Hydraulic fracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485a(e) or § 60.5401a(f)(2).

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Initial flowback stage means the period during a well completion operation which begins at the onset of flowback and ends at the separation flowback stage.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Intermittent/snap-action pneumatic controller means a pneumatic controller that is designed to vent non-continuously.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Liquid collection system means tankage and/or lines at a well site to contain liquids from one or more wells or to convey liquids to another site.

Local distribution company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

Low pressure well means a well that satisfies at least one of the following conditions:

(1) The static pressure at the wellhead following fracturing but prior to the onset of flowback is less than the flow line pressure;

(2) The pressure of flowback fluid immediately before it enters the flow line, as determined under § 60.5432a, is less than the flow line pressure; or

(3) Flowback of the fracture fluids will not occur without the use of artificial lift equipment.

Major production and processing equipment means reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water, for the purpose of determining whether a well site is a wellhead only well site.

Maximum average daily throughput means the following:

(1) For storage vessels that commenced construction, reconstruction, or modification after September 18, 2015, and on and before November 16, 2020, *maximum average daily throughput* means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

(2) For storage vessels that commenced construction, reconstruction, or modification after November 16, 2020, *maximum average daily throughput* means the earliest calculation of daily average throughput, determined as described in paragraph (3) or (4) of this definition, to an individual storage vessel over the days that production is routed to that storage vessel during the 30-day PTE evaluation period employing generally accepted methods specified in § 60.5365a(e)(1).

(3) If throughput to the individual storage vessel is measured on a daily basis (*e.g.,* via level gauge automation or daily manual gauging), the maximum average daily throughput is the average of all daily throughputs for days on which throughput was routed to that storage vessel during the 30-day evaluation period; or

(4) If throughput to the individual storage vessel is not measured on a daily basis (*e.g.,* via manual gauging at the start and end of loadouts), the maximum average daily throughput is the highest, of the average daily throughputs, determined for any production period to that storage vessel during the 30-day evaluation period, as determined by averaging total throughput to that storage vessel over each production period. A production period begins when production begins to be routed to a storage vessel and ends either when throughput is routed away from that storage vessel or when a loadout occurs from that storage vessel, whichever happens first. Regardless of the determination methodology, operators must not include days during which throughput is not routed to an individual storage vessel when calculating maximum average daily throughput for that storage vessel.

Natural gas-driven diaphragm pump means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of this subpart. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Plug drill-out means the removal of a plug (or plugs) that was used to isolate different sections of the well.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

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.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Qualified Professional Engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere, or other mechanism that provides the same function.

Recovered gas means gas recovered through the separation process during flowback.

Recovered liquids means any crude oil, condensate or produced water recovered through the separation process during flowback.

Reduced emissions completion means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2).

Removed from service means that a storage vessel affected facility has been physically isolated and disconnected from the process for a purpose other than maintenance in accordance with § 60.5395a(c)(1).

Repaired means, for the purposes of fugitive emissions components, that fugitive emissions components are adjusted, replaced, or otherwise altered, in order to eliminate fugitive emissions as defined in § 60.5397a and resurveyed as specified in § 60.5397a(h)(4) and it is verified that emissions from the fugitive emissions components are below the applicable fugitive emissions definition.

Returned to service means that a storage vessel affected facility that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel affected facility; or

(2) Installed in any location covered by this subpart and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly 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 regulated materials and/or incorporated into a product; and/or recovered.

Salable quality gas means natural gas that meets the flow line or collection system operator specifications, regardless of whether such gas is sold.

Screenout means an attempt to clear proppant from the wellbore to dislodge the proppant out of the well.

Separation flowback stage means the period during a well completion operation when it is technically feasible for a separator to function. The separation flowback stage ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.

Startup of production means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water, except as otherwise provided in this definition. For the purposes of the fugitive monitoring requirements of § 60.5397a, *startup of production* means the beginning of the continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of § 60.5395a(c)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by § 60.5420a(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

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

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A-6 of this part.

Total SO_2 equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO_2 to the quantity of SO_2 that would be obtained if all reduced sulfur compounds were converted to SO_2 (ppmv or kg/dscm (lb/dscf)).

UIC Class I oilfield disposal well means a well with a UIC Class I permit that meets the definition in 40 CFR 144.6(a)(2) and receives eligible fluids from oil and natural gas exploration and production operations.

UIC Class II oilfield disposal well means a well with a UIC Class II permit where wastewater resulting from oil and natural gas production operations is injected into underground porous rock formations not productive of oil or gas, and sealed above and below by unbroken, impermeable strata.

Underground storage vessel means a storage vessel stored below ground.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well completion means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a well affected facility.

Well completion vessel means a vessel that contains flowback during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a tank or other vessel that is skid-mounted or portable. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart.

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards at § 60.5397a, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (*e.g.,* centralized tank batteries). Also, for the purposes of the fugitive emissions standards at § 60.5397a, a well site does not include:

(1) UIC Class II oilfield disposal wells and disposal facilities;

(2) UIC Class I oilfield disposal wells; and

(3) The flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Wellhead only well site means, for the purposes of the fugitive emissions standards at § 60.5397a, a well site that contains one or more wellheads and no major production and processing equipment.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57072, Sept. 14, 2020; 85 FR 57458, Sept. 15, 2020; 89 FR 17043, Mar. 8, 2024]

§ 60.5432a How do I determine whether a well is a low pressure well using the low pressure well equation?

(a) To determine that your well is a low pressure well subject to § 60.5375a(f), you must determine whether the characteristics of the well are such that the well meets the definition of low pressure well in § 60.5430a. To determine that the well meets the definition of low pressure well in § 60.5430a, you must use the low pressure well equation below:

$$P_L\ (psia) = 0.495 \times P_R - \frac{q_g}{q_g+q_o+q_w}[0.05 \times P_R + 0.038 \times L - 67.578] - \left[\frac{q_o}{q_g+q_o+q_w} \times \frac{\rho_o}{144} + \frac{q_w}{q_g+q_o+q_w} 0.433\right] \cdot L$$

Where:

(1) P_L is the pressure of flowback fluid immediately before it enters the flow line, expressed in pounds force per square inch (psia), and is to be calculated using the equation above;

(2) P_R is the pressure of the reservoir containing oil, gas, and water at the well site, expressed in psia;

(3) L is the true vertical depth of the well, expressed in feet (ft);

(4) q_o is the flow rate of oil in the well, expressed in cubic feet/second (cu ft/sec);

(5) q_g is the flow rate of gas in the well, expressed in cu ft/sec;

(6) q_w is the flow rate of water in the well, expressed in cu ft/sec;

(7) ρ_o is the density of oil in the well, expressed in pounds mass per cubic feet (lbm/cu ft).

(b) You must determine the four values in paragraphs (a)(4) through (7) of this section, using the calculations in paragraphs (b)(1) through (b)(15) of this section.

(1) Determine the value of the bottom hole pressure, P_{BH} (*psia*), based on available information at the well site, or by calculating it using the reservoir pressure, P_R (*psia*), in the following equation:

$$P_{BH}\ (psia) = \frac{1}{2} P_R$$

(2) Determine the value of the bottom hole temperature, T_{BH} (*F*), based on available information at the well site, or by calculating it using the true vertical depth of the well, *L (ft)*, in the following equation:

T_{BH} (*F*) = (0.014 × *L*) + 79.081

(3) Calculate the value of the applicable natural gas specific gravity that would result from a separator pressure of 100 psig, γ_{gs}, using the following equation with: Separator at standard conditions (pressure, *p* = 14.7 (*psia*), temperature, T = 60 (*F*)); the oil API gravity at the well site, γ_0; and the gas specific gravity at the separator under standard conditions, γ_{gp} = 0.75:

$$\gamma_{gs} = \gamma_{gp} \cdot \left(1.0 + 5.912\ x\ 10^{-5} \cdot \gamma_o \cdot T \cdot log\left(\frac{p}{114.7}\right)\right)$$

(4) Calculate the value of the applicable dissolved GOR, *Rs (scf/STBO)*, using the following equation with: The bottom hole pressure, P_{BH} (*psia*), determined in (b)(1) of this section; the bottom hole temperature, T_{BH} (*F*), determined in (b)(2) of this section; the gas gravity at separator pressure of 100 psig, γ_{gs}, calculated in (b)(3) of this section; the oil API gravity, γ_o, at the well site; and the constants, C1, C2, and C3, found in Table A:

$$R_s\left(\frac{scf}{STBO}\right) = C1 \cdot \gamma_{gs} \cdot {P_{BH}}^{C2} \cdot exp\left[C3\left(\frac{\gamma_o}{T_{BH} + 460}\right)\right]$$

Table A—Coefficients for the correlation for R_s

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	0.0362	0.0178
C2	1.0937	1.1870
C3	25.7240	23.931

(5) Calculate the value of the oil formation volume factor, *Bo (bbl/STBO)*, using the following equation with: the bottom hole temperature, T_{BH} (*F*), determined in paragraph (b)(2) of this section; the gas gravity at separator pressure of 100 psig, γ_{gs}, calculated in paragraph (b)(3) of this section; the dissolved GOR, Rs (scf/STBO), calculated in paragraph (b)(4) of this section; the oil API gravity, γo, at the well site; and the constants, C1, C2, and C3, found in Table B:

$$B_o\left(\frac{bbl}{STBO}\right) = 1.0 + C1 \cdot R_s + (T_{BH} - 60)\left(\frac{\gamma_o}{\gamma_{gs}}\right) \cdot (C2 + C3 \cdot R_s)$$

Table B—Coefficients for the Correlation for B_o

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	4.677×10^{-4}	4.670×10^{-4}
C2	1.751×10^{-5}	1.100×10^{-5}
C3	-1.811×10^{-8}	1.337×10^{-9}

(6) Calculate the density of oil at the wellhead,

$$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right),$$

using the following equation with the value of the oil API gravity, γo, at the well site:

$$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right) = \frac{141.5}{\gamma_o + 131.5} \times 62.4$$

(7) Calculate the density of oil at bottom hole conditions,

$$\rho_{BH}\ (\frac{lbm}{cu\ ft}),$$

using the following equation with: the dissolved GOR, Rs (scf/STBO), calculated in paragraph (b)(4) of this section; the oil formation volume factor, Bo (bbl/STBO), calculated in paragraph (b)(5) of this section; the oil density at the wellhead,

$$\rho_{WH}\ (\frac{lbm}{cu\ ft}),$$

calculated in paragraph (b)(6) of this section; and the dissolved gas gravity, γ_{gd} = 0.77:

$$\rho_{BH}\ (\frac{lbm}{cu\ ft}) = \frac{\rho_{WH}\ +\ 0.0136 \times Rs \times \gamma_{gd}}{Bo}$$

(8) Calculate the density of oil in the well,

$$\rho_{o}\ (\frac{lbm}{cu\ ft}),$$

using the following equation with the density of oil at the wellhead,

$$\rho_{WH}\ (\frac{lbm}{cu\ ft}),$$

calculated in paragraph (b)(6) of this section; and the density of oil at bottom hole conditions,

$$\rho_{BH}\ (\frac{lbm}{cu\ ft}),$$

calculated in paragraph (b)(7) of this section:

$$\rho_{o}\left(\frac{lbm}{cu\ ft}\right) = 0.5 \times (\rho_{WH} + \rho_{BH})$$

(9) Calculate the oil flow rate, q_o (*cu ft/sec,*) using the following equation with: the oil formation volume factor, *Bo* (bbl/STBO), as calculated in paragraph (b)(5) of this section; and the estimated oil production rate at the well head, *Qo* (STBO/day):

$$q_o\left(\frac{cu\ ft}{sec}\right) = \mathrm{Qo}\left(\frac{\mathrm{STBO}}{\mathrm{day}}\right) \times \mathrm{Bo}\left(\frac{\mathrm{bbl}}{\mathrm{STBO}}\right) \times 5.614(\frac{\mathrm{cu\ ft}}{\mathrm{bbl}}) \times \frac{1}{24 \times 60 \times 60}(\frac{day}{sec})$$

(10) Calculate the critical pressure, P_c (psia), and critical temperature, T_c (R), using the equations below with: Gas gravity at standard conditions (pressure, *P* = 14.7 (*psia*), temperature, T = 60 (*F*)), γ = 0.75; and where the mole fractions of nitrogen, carbon dioxide and hydrogen sulfide in the gas are X_{N_2} = 0.168225, X_{CO_2} = 0.013163, and X_{H_2S} = 0.013680, respectively:

$P_c(psia) = 678 - 50 \cdot (\gamma_g - 0.5) - 206.7 \cdot X_{N_2} + 440 \cdot X_{CO_2} + 606.7 \cdot X_{H_2S}$

$T_c(R) = 326 + 315.7 \cdot (\gamma_g - 0.5) - 240 \cdot X_{N_2} - 88.3 \cdot XCO_2 + 133.3 \cdot X_{H_2S}$

(11) Calculate reduced pressure, P_r, and reduced temperature, T_r, using the following equations with: the bottom hole pressure, P_{BH}, as determined in paragraph (b)(1) of this section; the bottom hole temperature, T_{BH} (*F*), as determined in paragraph (b)(2) of this section in the following equations:

$$P_r = \frac{P_{BH}}{P_c}$$

$$T_r = \frac{T_{BH} + 460}{T_c}$$

(12)

(i) Calculate the gas compressibility factor, *Z*, using the following equation with the reduced pressure, P_r, calculated in paragraph (b)(11) of this section:

$$z = A + \frac{(1 - A)}{e^B} + C \cdot p_r^D$$

(ii) The values for A, B, C, D in the above equation, are calculated using the following equations with the reduced pressure, P_r, and reduced temperature, T_r, calculated in paragraph (b)(11) of this section:

$$A = 1.39 \cdot (T_r - 0.92)^{0.5} - 0.36 * T_r - 0.101$$

$$B = (0.62 - 0.23 \cdot T_r) \cdot P_r + \left(\frac{0.066}{(T_r - 0.86)} - 0.037\right) \cdot P_r^2 + \frac{0.32}{10^{9 \cdot (T_r - 1)}} \cdot P_r^6$$

$$C = (0.132 - 0.32 \cdot \log(T_r))$$

$$D = 10^{0.3106 - 0.49 \cdot T_r + 0.1824 \cdot T_r^2}$$

(13) Calculate the gas formation volume factor,

$$B_g\left(\frac{cuft}{scf}\right),$$

using the bottom hole pressure, $P_{BH}(psia)$, as determined in paragraph (b)(1) of this section; and the bottom hole temperature, $T_{BH}(F)$, as determined in paragraph (b)(2) of this section:

$$B_g\left(\frac{cuft}{scf}\right) = 0.0283 \cdot \frac{Z \cdot (T_{BH} + 460)}{P_{BH}}()$$

(14) Calculate the gas flow rate,

$$q_g\left(\frac{cu\ ft}{sec}\right),$$

using the following equation with: the value of gas formation volume factor,

$$B_g\left(\frac{cuft}{scf}\right),$$

calculated in paragraph (b)(13) of this section; the estimated gas production rate, Qg (scf/day); the estimated oil production rate, Qo (STBO/day); and the dissolved GOR, Rs (scf/STBO), as calculated in paragraph (b)(4) of this section:

$$q_g\left(\frac{cf}{sec}\right) = (Q_g - R_s \cdot Q_o) \cdot B_g \cdot \frac{1}{24x60x60}$$

(15) Calculate the flow rate of water in the well, q_w (*cu ft/sec*), using the following equation with the water production rate Qw (bbl/day) at the well site:

$$q_w\left(\frac{cf}{sec}\right) = \mathrm{Qw}\left(\frac{\mathrm{bbl}}{\mathrm{day}}\right) \times 5.614\left(\frac{\mathrm{cf}}{\mathrm{bbl}}\right) \times \frac{1}{24 \times 60 \times 60}\left(\frac{day}{sec}\right)$$

§§ 60.5433a-60.5439a [Reserved]

Table 1 to Subpart OOOOa of Part 60—Required Minimum Initial SO_2 Emission Reduction Efficiency (Z_i)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0 < X < 5.0	5.0 < X < 15.0	15.0 < X < 300.0	X > 300.0
Y > 50	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller.		
20 < Y < 50	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller		97.9

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0 < X < 5.0	5.0 < X < 15.0	15.0 < X < 300.0	X > 300.0
10 < Y < 20	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 93.5, whichever is smaller	93.5	93.5
Y < 10	79.0	79.0	79.0	79.0

Table 2 to Subpart OOOOa of Part 60—Required Minimum SO_2 Emission Reduction Efficiency (Z_c)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0 < X < 5.0	5.0 < X < 15.0	15.0 < X < 300.0	X > 300.0
Y > 50	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller.		
20 < Y < 50	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 97.5, whichever is smaller		97.5
10 < Y < 20	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller	90.8	90.8
Y < 10	74.0	74.0	74.0	74.0

X = The sulfur feed rate from the sweetening unit (*i.e.,* the H_2S in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.

Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent H_2S (dry basis) rounded to one decimal place.

Z = The minimum required sulfur dioxide (SO_2) emission reduction efficiency, expressed as percent carried to one decimal place. Z_i refers to the reduction efficiency required at the initial performance test. Z_c refers to the reduction efficiency required on a continuous basis after compliance with Z_i has been demonstrated.

As stated in § 60.5425a, you must comply with the following applicable General Provisions:

Table 3 to Subpart OOOOa of Part 60—Applicability of General Provisions to Subpart OOOOa

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.1	General applicability of the General Provisions	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5430a.
§ 60.3	Units and abbreviations	Yes	
§ 60.4	Address	Yes	
§ 60.5	Determination of construction or modification	Yes	
§ 60.6	Review of plans	Yes	

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.7	Notification and record keeping	Yes	Except that § 60.7 only applies as specified in § 60.5420a(a).
§ 60.8	Performance tests	Yes	Except that the format of performance test reports is described in § 60.5420a(b). Performance testing is required for control devices used on storage vessels, centrifugal compressors, and pneumatic pumps, except that performance testing is not required for a control device used solely on pneumatic pump(s).
§ 60.9	Availability of information	Yes	
§ 60.10	State authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart OOOOa.
§ 60.12	Circumvention	Yes	
§ 60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.
§ 60.14	Modification	Yes	To the extent any provision in § 60.14 conflicts with specific provisions in subpart OOOOa, it is superseded by subpart OOOOa provisions.
§ 60.15	Reconstruction	Yes	Except that § 60.15(d) does not apply to wells, pneumatic controllers, pneumatic pumps, centrifugal compressors, reciprocating compressors, storage vessels, or the collection of fugitive emissions components at a well site or the collection of fugitive emissions components at a compressor station.
§ 60.16	Priority list	Yes	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device and work practice requirements	Yes	
§ 60.19	General notification and reporting requirement	Yes	

[81 FR 35898, June 3, 2016, as amended at 85 FR 57460, Sept. 15, 2020]

Displaying title 40, up to date as of 5/07/2024. Title 40 was last amended 5/07/2024.

There have been changes in the last two weeks to Subpart OOOO.

Title 40 —Protection of Environment
Chapter I —Environmental Protection Agency
Subchapter C —Air Programs
Part 60 —Standards of Performance for New Stationary Sources

ENHANCED CONTENT - TABLE OF CONTENTS

Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After August 23, 2011, and on or Before September 18, 2015

Source: 77 FR 49542, Aug. 16, 2012, unless otherwise noted.

§ 60.5360 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities that commence construction, modification, or reconstruction after August 23, 2011, and on or before September 18, 2015.

[89 FR 17035, Mar. 8, 2024]

§ 60.5365 Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (g) of this section for which you commence construction, modification, or reconstruction after August 23, 2011, and on or before September 18, 2015. An affected facility must continue to comply with the requirements of this subpart until it begins complying with a more stringent requirement, that applies to the same affected facility, in an approved, and effective, state or Federal plan that implements subpart OOOOc of this part, or modifies or reconstructs after December 6, 2022, and thus becomes subject to subpart OOOOb of this part.

(a) Each gas well affected facility, which is a single natural gas well.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals that is located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(d)

(1) For the oil production segment (between the wellhead and the point of custody transfer to an oil pipeline), each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour.

(2) For the natural gas production segment (between the wellhead and the point of custody transfer to the natural gas transmission and storage segment and not including natural gas processing plants), each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour.

(3) For natural gas processing plants, each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller.

(e) Each storage vessel affected facility, which is a single storage vessel located in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment, and has the potential for VOC emissions equal to or greater than 6 tons per year (tpy) as determined according to this section by October 15, 2013, for Group 1 storage vessels and by April 15, 2014, or 30 days after startup (whichever is later) for Group 2 storage vessels, except as provided in paragraphs (e)(1) through (4) of this section. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this section. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, State, local or Tribal authority.

(1) For each new, modified or reconstructed storage vessel receiving liquids pursuant to the standards for gas well affected facilities in § 60.5375, including wells subject to § 60.5375(f), you must determine the potential for VOC emissions within 30 days after startup of production.

(2) A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart.

(3) For storage vessels not subject to a legally and practically enforceable limit in an operating permit or other requirement established under Federal, state, local or tribal authority, any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(3)(i) through (iv) of this section.

(i) You meet the cover requirements specified in § 60.5411(b).

(ii) You meet the closed vent system requirements specified in § 60.5411(c).

(iii) You maintain records that document compliance with paragraphs (e)(3)(i) and (ii) of this section.

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs (e)(3)(i) and (ii) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(4) The following requirements apply immediately upon startup, startup of production, or return to service. A storage vessel affected facility that is reconnected to the original source of liquids is a storage vessel affected facility subject to the same requirements that applied before being removed from service. Any storage vessel that is used to replace any storage vessel affected facility is subject to the same requirements that apply to the storage vessel affected facility being replaced.

(5) A storage vessel with a capacity greater than 100,000 gallons used to recycle water that has been passed through two stage separation is not a storage vessel affected facility.

(f) The group of all equipment, except compressors, within a process unit is an affected facility.

(1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by §§ 60.5400, 60.5401, 60.5402, 60.5421, and 60.5422 of this subpart if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the provisions of §§ 60.5400, 60.5401, 60.5402, 60.5421, and 60.5422 of this subpart.

(3) The equipment within a process unit of an affected facility located at onshore natural gas processing plants and described in paragraph (f) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG or GGGa of this part.

(g) Sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells.

(1) Each sweetening unit that processes natural gas is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in § 60.5423(c) but are not required to comply with §§ 60.5405 through 60.5407 and §§ 60.5410(g) and 60.5415(g) of this subpart.

(4) Sweetening facilities producing acid gas that is completely reinjected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§ 60.5405 through 60.5407, 60.5410(g), 60.5415(g), and 60.5423 of this subpart.

(h) The following provisions apply to gas well facilities that are hydraulically refractured.

(1) A gas well facility that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of § 60.5375 are met. For purposes of this provision, the dates specified in § 60.5375(a) do not apply, and such facilities, as of October 15, 2012, must meet the requirements of § 60.5375(a)(1) through (4).

(2) A well completion operation following hydraulic refracturing at a gas well facility not conducted pursuant to § 60.5375 is a modification to the gas well affected facility.

(3) Refracturing of a gas well facility does not affect the modification status of other equipment, process units, storage vessels, compressors, or pneumatic controllers located at the well site.

(4) A gas well facility initially constructed after August 23, 2011, and on or before September 18, 2015 is considered an affected facility regardless of this provision.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58435, Sept. 23, 2013; 79 FR 79036, Dec. 31, 2014; 80 FR 48268, Aug. 12, 2015; 81 FR 35896, June 3, 2016; 85 FR 57069, Sept. 14, 2020; 89 FR 17035, Mar. 8, 2024]

§ 60.5370 When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than October 15, 2012 or upon startup, whichever is later.

(b) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating 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, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

(d) You are deemed to be in compliance with this subpart if you are in compliance with all applicable provisions of subpart OOOOa of this part.

[77 FR 49542, Aug. 16, 2012, as amended at 81 FR 35896, June 3, 2016]

§ 60.5371 What standards apply to super-emitter events?

This section applies to super-emitter events. For purposes of this section, a super-emitter event is defined as any emissions event that is located at an individual well site or compressor station and that is detected using remote detection methods and has a quantified emission rate of 100 kg/hr of methane or greater. Upon receiving a notification of a super emitter event issued by the EPA under § 60.5371b(c), owners or operators must take the actions listed in paragraphs (a) and (b) of this section. Within 5 calendar days of receiving a notification from the EPA of a super-emitter event, the owner or operator of an oil and natural gas facility (*e.g.,* a well site, centralized production facility, natural gas processing plant, or compressor station) must initiate a super-emitter event investigation.

(a) ***Identification of super-emitter events.***

(1) If you do not own or operate an oil and natural gas facility within 50 meters from the latitude and longitude provided in the notification subject to the regulation under this subpart, report this result to the EPA under paragraph (e) of this section. Your super-emitter event investigation is deemed complete under this subpart.

(2) If you own or operate an oil and natural gas facility within 50 meters from the latitude and longitude provided in the notification subject to regulation under this subpart, you must investigate to determine the source of super-emitter event. The investigation may include but is not limited to the actions specified below in paragraphs (a)(2)(i) through (iii) of this section.

(i) Review any maintenance activities or process activities from the affected facilities subject to regulation under this subpart, starting from the date of detection of the super-emitter event as identified in the notification, until the date of investigation, to determine if the activities indicate any potential source(s) of the super-emitter event emissions.

(ii) Review all monitoring data from control devices (*e.g.,* flares) from the affected facilities subject to regulation under this subpart from the initial date of detection of the super-emitter event as identified in the notification, until the date of receiving the notification from the EPA to identify malfunctions of control devices or periods when the control devices were not in compliance with applicable requirements and that indicate a potential source of the super-emitter event emissions.

(iii) Screen the entire well site or compressor station with OGI, or Method 21 of appendix A-7 to this part, or an alternative test method(s) approved per § 60.5398b(d), to determine if a super-emitter event is present.

(b) ***Super-emitter event report.*** For equipment subject to regulation under this subpart, you must submit the results of the super-emitter event investigation conducted under paragraph (a) of this section to the EPA in accordance with paragraph (b)(1) of this section. If the super-emitter event (*i.e.,* emission at 100 kg/hr of methane or more) is ongoing at the time of the initial report, submit the additional information in accordance with paragraph (b)(2) of this section. You must attest to the information included in the report as specified in paragraph (b)(3) of this section.

(1) Within 15 days of receiving a notification from the EPA under § 60.5371b(c), you must submit a report of the super-emitter event investigation conducted under paragraph (a) of this section through the Super-Emitter Program Portal. You must include the applicable information in paragraphs (b)(1)(i) through (viii) of this section in the report. If you have identified a demonstrable error in the notification, the report may include a statement of the demonstrable error.

(i) Notification Report ID of the super-emitter event notification.

(ii) Identification of whether you are the owner or operator of an oil and natural gas facility within 50 meters from the latitude and longitude provided in the EPA notification. If you do not own or operate an oil and natural gas facility within 50 meters from the latitude and longitude provided in the EPA notification, you are not required to report the information in paragraphs (b)(1)(iii) through (viii) of this section.

(iii) General identification information for the facility, including, facility name, the physical address, applicable ID Number (*e.g.,* EPA ID Number, API Well ID Number), the owner or operator or responsible official (where applicable) and their email address.

(iv) Identification of whether there is an affected facility or associated equipment subject to regulation under this subpart at a well site or compressor station you own or operate within 50 meters from the latitude and longitude provided in the EPA notification.

(v) Indication of whether you were able to identify the source of the super-emitter event. If you indicate you were unable to identify the source of the super-emitter event, you must certify that all applicable investigations specified in paragraphs (d)(6)(i) through (v) of this section have been conducted for all affected facilities and associated equipment subject to this subpart that are at this oil and natural gas facility, and you have determined that the affected facilities and associated equipment are not the source of the super-emitter event. If you indicate that you were not able to identify the source of the super-emitter event, you are not required to report the information in paragraphs (b)(1)(vi) through (viii) of this section.

(vi) The source(s) of the super-emitter event.

(vii) Identification of whether the source of the super-emitter event is an affected facility or associated equipment subject to regulation under of this subpart. If the source of the super-emitter event is equipment subject to regulation under this subpart, identify the applicable regulation(s) under this subpart.

(viii) Indication of whether the super-emitter event is ongoing at the time of the initial report submittal (*i.e.,* emission at 100 kg/hr of methane or more).

(A) If the super-emitter event is not ongoing at the time of the initial report submittal, provide the estimated date and time the super-emitter event ended.

(B) If the super-emitter event is ongoing at the time of the initial report submittal, provide a short narrative of your plan to end the super-emitter event, including the targeted end date for the efforts to be completed and the super-emitter event ended.

(2) If the super-emitter event is ongoing at the time of the initial report submittal, within 5 business days of the date the super-emitter event ends, you must update your initial report through the Super-Emitter Program Portal (available at *http://www.epa.gov/super-emitter*) to provide the end date and time of the super-emitter event.

(3) You must sign the following attestation must be signed by the owner or operator into when submitting data into the Super-Emitter Program Portal: "I certify that the information provided in this report regarding the specified super-emitter event was prepared under my direction or supervision. I further certify that the investigations were conducted, and this report was prepared pursuant to the requirements of § 60.5371(a) and (b). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that knowingly false statements may be punishable by fine or imprisonment."

[89 FR 17035, Mar. 8, 2024]

§ 60.5375 What standards apply to gas well affected facilities?

If you are the owner or operator of a gas well affected facility, you must comply with paragraphs (a) through (f) of this section.

(a) Except as provided in paragraph (f) of this section, for each well completion operation with hydraulic fracturing begun prior to January 1, 2015, you must comply with the requirements of paragraphs (a)(3) and (4) of this section unless a more stringent state or local emission control requirement is applicable; optionally, you may comply with the requirements of paragraphs (a)(1) through (4) of this section. For each new well completion operation with hydraulic fracturing begun on or after January 1, 2015, you must comply with the requirements in paragraphs (a)(1) through (4) of this section. You must maintain a log as specified in paragraph (b).

(1) For each stage of the well completion operation, as defined in § 60.5430, follow the requirements specified in paragraph (a)(1)(i) and (ii) of this section.

(i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the initial flowback stage is not subject to control under this section.

(ii) During the separation flowback stage, route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the liquids into the well or another well or route the recovered liquids to a collection system. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is infeasible to route the recovered gas as required above, follow the requirements in paragraph (a)(3) of this section. If, at any time during the separation flowback stage, it is not technically feasible for a separator to function, you must comply with (a)(1)(i) of this section.

(2) All salable quality recovered gas must be routed to the gas flow line as soon as practicable. In cases where salable quality gas cannot be directed to the flow line, you must follow the requirements in paragraph (a)(3) of this section.

(3) You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source.

(4) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

(b) You must maintain a log for each well completion operation at each gas well affected facility. The log must be completed on a daily basis for the duration of the well completion operation and must contain the records specified in § 60.5420(c)(1)(iii).

(c) You must demonstrate initial compliance with the standards that apply to gas well affected facilities as required by § 60.5410.

(d) You must demonstrate continuous compliance with the standards that apply to gas well affected facilities as required by § 60.5415.

(e) You must perform the required notification, recordkeeping and reporting as required by § 60.5420.

(f)

(1) For each gas well affected facility specified in paragraphs (f)(1)(i) and (ii) of this section, you must comply with the requirements of paragraphs (f)(2) and (3) of this section.

(i) Each well completion operation with hydraulic fracturing at a wildcat or delineation well.

(ii) Each well completion operation with hydraulic fracturing at a non-wildcat low pressure gas well or non-delineation low pressure gas well.

(2) Route the flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source. You must also comply with paragraphs (a)(4) and (b) through (e) of this section.

(3) You must maintain records specified in § 60.5420(c)(1)(iii) for wildcat, delineation and low pressure gas wells.

[77 FR 49542, Aug. 16, 2012, as amended at 79 FR 79037, Dec. 31, 2014]

§ 60.5380 What standards apply to centrifugal compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section for each centrifugal compressor affected facility.

(a)

(1) You must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411(b), that is connected through a closed vent system that meets the requirements of § 60.5411(a) and routed to a control device that meets the conditions specified in § 60.5412(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5410(b).

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5415(b).

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58436, Sept. 23, 2013]

§ 60.5385 What standards apply to reciprocating compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section or you must comply with paragraph (a)(3) of this section.

(1) Before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

(3) Collect the emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and route the rod packing emissions to a process through a closed vent system that meets the requirements of § 60.5411(a).

(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5410.

(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5415.

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

[77 FR 49542, Aug. 16, 2012, as amended at 79 FR 79037, Dec. 31, 2014]

§ 60.5390 What standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the VOC standards, based on natural gas as a surrogate for VOC, in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from this requirement.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety and positive actuation. However, you must tag such pneumatic controller with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller, as required in § 60.5420(c)(4)(ii).

(b)

(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in § 60.5420(c)(4)(iv).

(c)

(1) Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013, at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013, at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in § 60.5420(c)(4)(iii).

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5410.

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5415.

(f) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420, except that you are not required to submit the notifications specified in § 60.5420(a).

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58436, Sept. 23, 2013; 79 FR 79038, Dec. 31, 2014]

§ 60.5395 What standards apply to storage vessel affected facilities?

Except as provided in paragraph (h) of this section, you must comply with the standards in this section for each storage vessel affected facility.

(a)

(1) If you are the owner or operator of a Group 1 storage vessel affected facility, you must comply with paragraph (b) of this section.

(2) If you are the owner or operator of a Group 2 storage vessel affected facility, you must comply with paragraph (c) of this section.

(b) ***Requirements for Group 1 storage vessel affected facilities.*** If you are the owner or operator of a Group 1 storage vessel affected facility, you must comply with paragraphs (b)(1) and (2) of this section.

(1) You must submit a notification identifying each Group 1 storage vessel affected facility, including its location, with your initial annual report as specified in § 60.5420(b)(6)(iv).

(2) You must comply with paragraphs (d) through (g) of this section.

(c) ***Requirements for Group 2 storage vessel affected facilities.*** If you are the owner or operator of a Group 2 storage vessel affected facility, you must comply with paragraphs (d) through (g) of this section.

(d) You must comply with the control requirements of paragraph (d)(1) of this section unless you meet the conditions specified in paragraph (d)(2) of this section.

(1) Reduce VOC emissions by 95.0 percent according to the schedule specified in (d)(1)(i) and (ii) of this section.

(i) For each Group 2 storage vessel affected facility, you must achieve the required emissions reductions by April 15, 2014, or within 60 days after startup, whichever is later, except as otherwise provided below in paragraph (f) of this section. For storage vessel affected facilities receiving liquids pursuant to the standards for gas well affected facilities in § 60.5375, you must achieve the required emissions reductions within 60 days after startup of production as defined in § 60.5430.

(ii) For each Group 1 storage vessel affected facility, you must achieve the required emissions reductions by April 15, 2015.

(2) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology. Monthly calculations must be based on the average throughput for the month. Monthly calculations must be separated by at least 14 days. You must comply with paragraph (d)(1) of this section if your storage vessel affected facility meets the conditions specified in paragraphs (d)(2)(i) or (ii) of this section.

(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (d)(1) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.

(ii) If the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (d)(1) of this section within 30 days of the monthly calculation.

(e) ***Control requirements.***

(1) Except as required in paragraph (e)(2) of this section, if you use a control device to reduce emissions from your storage vessel affected facility, you must equip the storage vessel with a cover that meets the requirements of § 60.5411(b) and is connected through a closed vent system that meets the requirements of § 60.5411(c), and you must route emissions to a control device that meets the conditions specified in § 60.5412(c) and (d). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of § 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(f) ***Requirements for Group 1 and Group 2 storage vessel affected facilities that are removed from service or returned to service.*** If you remove a Group 1 or Group 2 storage vessel affected facility from service, you must comply with paragraphs (f)(1) through (3) of this section. A Group 1 or Group 2 storage vessel is not an affected facility under this subpart for the period that it is removed from service.

(1) For a storage vessel affected facility to be removed from service, you must comply with the requirements of paragraph (f)(1)(i) and (ii) of this section.

(i) You must completely empty and degas the storage vessel, such that the storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification as required in § 60.5420(b)(6)(vi) in your next annual report, identifying each storage vessel affected facility removed from service during the reporting period and the date of its removal from service.

(2) If a storage vessel identified in paragraph (f)(1)(ii) of this section is returned to service, you must determine its affected facility status as provided in § 60.5365(e).

(3) For each storage vessel affected facility returned to service during the reporting period, you must submit a notification in your next annual report as required in § 60.5420(b)(6)(vii), identifying each storage vessel affected facility and the date of its return to service.

(g) ***Compliance, notification, recordkeeping, and reporting.*** You must comply with paragraphs (g)(1) through (3) of this section.

(1) You must demonstrate initial compliance with standards as required by § 60.5410(h) and (i).

(2) You must demonstrate continuous compliance with standards as required by § 60.5415(e)(3).

(3) You must perform the required notification, recordkeeping and reporting as required by § 60.5420.

(h) ***Exemptions.*** This subpart does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, 40 CFR part 63, subparts G, CC, HH, or WW.

[78 FR 58436, Sept. 23, 2013, as amended at 79 FR 79038, Dec. 31, 2014]

§ 60.5400 What equipment leak standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to the group of all equipment, except compressors, within a process unit.

(a) You must comply with the requirements of §§ 60.482-1a(a), (b), and (d), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in § 60.5401.

(b) You may elect to comply with the requirements of §§ 60.483-1a and 60.483-2a, as an alternative.

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of § 60.5402 of this subpart.

(d) You must comply with the provisions of § 60.485a of this part except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§ 60.486a and 60.487a of this part except as provided in §§ 60.5401, 60.5421, and 60.5422 of this part.

(f) You must use the following provision instead of § 60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in § 60.17) must be used.

§ 60.5401 What are the exceptions to the equipment leak standards for affected facilities at onshore natural gas processing plants?

(a) You may comply with the following exceptions to the provisions of § 60.5400(a) and (b).

(b)

(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in § 60.485a(b) except as provided in § 60.5400(c) and in paragraph (b)(4) of this section, and § 60.482-4a(a) through (c) of subpart VVa.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)

(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in § 60.482-9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)

(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and § 60.482-4a(b)(1) of subpart VVa.

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of § 60.482-5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§ 60.482-2a(a)(1), 60.482-7a(a), 60.482-11a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§ 60.482-2a(a)(1), 60.482-7a(a), 60.482-11a(a), and paragraph (b)(1) of this section.

(f) An owner or operator may use the following provisions instead of § 60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86-96 (incorporated by reference as specified in § 60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302 °F) as determined by ASTM Method D86-96 (incorporated by reference as specified in § 60.17).

(g) An owner or operator may use the following provisions instead of § 60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in § 60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

[77 FR 49542, Aug. 16, 2012, as amended at 79 FR 79038, Dec. 31, 2014]

§ 60.5402 What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

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

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) The Administrator will treat applications under this section according to the following criteria, except in cases where the Administrator concludes that other criteria are appropriate:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) If the applicant is an owner or operator of an affected facility, the applicant must commit in writing to operate and maintain the alternative means so as to achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard.

§ 60.5405 What standards apply to sweetening units at onshore natural gas processing plants?

(a) During the initial performance test required by § 60.8(b), you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

§ 60.5406 What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?

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

(b) During a performance test required by § 60.8, you must determine the minimum required reduction efficiencies (Z) of SO_2 emissions as required in § 60.5405(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$$X = KQ_aY$$

Where:
X = average sulfur feed rate, Mg/D (LT/D).
Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).
Y = average H_2S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.
K = (32 kg S/kg-mole)/((24.04 dscm/kg-mole)(1000 kg S/Mg)).
= 1.331×10^{-3}Mg/dscm, for metric units.
= (32 lb S/lb-mole)/((385.36 dscf/lb-mole)(2240 lb S/long ton)).
= 3.707×10^{-5} long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in § 60.5408 or a chromatographic procedure following ASTM E260-96 (incorporated by reference as specified in § 60.17) to determine the H_2S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H_2S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (b)(3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO_2 emissions.

(c) You must determine compliance with the SO_2 standards in § 60.5405(a) or (b) as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$$R = (100S)\frac{}{S+E}$$

(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage vessels. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$$E = \frac{C_e Q_{sd}}{K_1}$$

Where:
E = emission rate of sulfur per run, kg/hr.
C_e = concentration of sulfur equivalent (SO^{2+} reduced sulfur), g/dscm (lb/dscf).
Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).
K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO_2 and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of appendix A to part 60 of this chapter to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m^2 or more, and the centroid is more than 1 m (39 in.) from the wall.

(i) You must use Method 6 of appendix A to part 60 of this chapter to determine the SO_2 concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent.

(ii) You must use Method 15 of appendix A to part 60 of this chapter to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft^3/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iii) You must use Method 16A or Method 15 of appendix A to part 60 of this chapter or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17) to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use Method 2 of appendix A to part 60 of this chapter to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

§ 60.5407 What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

(a) If your sweetening unit affected facility is located at an onshore natural gas processing plant and is subject to the provisions of § 60.5405(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

(1) ***The accumulation of sulfur product over each 24-hour period.*** The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage vessels with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ±2 percent of the 24-hour sulfur accumulation.

(2) ***The** H_2S **concentration in the acid gas from the sweetening unit for each 24-hour period.*** At least one sample per 24-hour period must be collected and analyzed using the equation specified in § 60.5406(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is within ±20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ±20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) ***The average acid gas flow rate from the sweetening unit.*** You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) ***The sulfur feed rate (X).*** For each 24-hour period, you must compute X using the equation specified in § 60.5406(b)(1).

(5) ***The required sulfur dioxide emission reduction efficiency for the 24-hour period.*** You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of § 60.5405(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) ***A continuous monitoring system to measure the total sulfur emission rate (E) of** SO_2**in the gases discharged to the atmosphere.*** The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with § 60.5405(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ±1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of § 60.8 to demonstrate compliance with the standards under § 60.5405, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under § 60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO_2 equivalent in the gases discharged to the atmosphere. The SO_2 equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock interval. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in § 60.5406(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H_2S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

$$R = \frac{K_2 S}{X}$$

Where:
R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.
K_2 = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).
S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).
X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by § 60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of § 60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by § 60.13(c), Performance Specification 2 of appendix B to part 60 of this chapter must apply, and Method 6 must be used for systems required by paragraph (b) of this section.

§ 60.5408 What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A-80-20-A, Entry II-I-67).

(a) When an instantaneous sample is desired and H_2S concentration is ten grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than ten grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) ***Apparatus.*** (See Figure 1 of this subpart) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top which connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) ***Reagents.***

(1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml = 0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) Starch solution. Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) ***Procedure.*** Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine thru (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then, Grains H_2S per 100 cubic foot of gas = 100(D-C)

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S-free gas or air, is required.

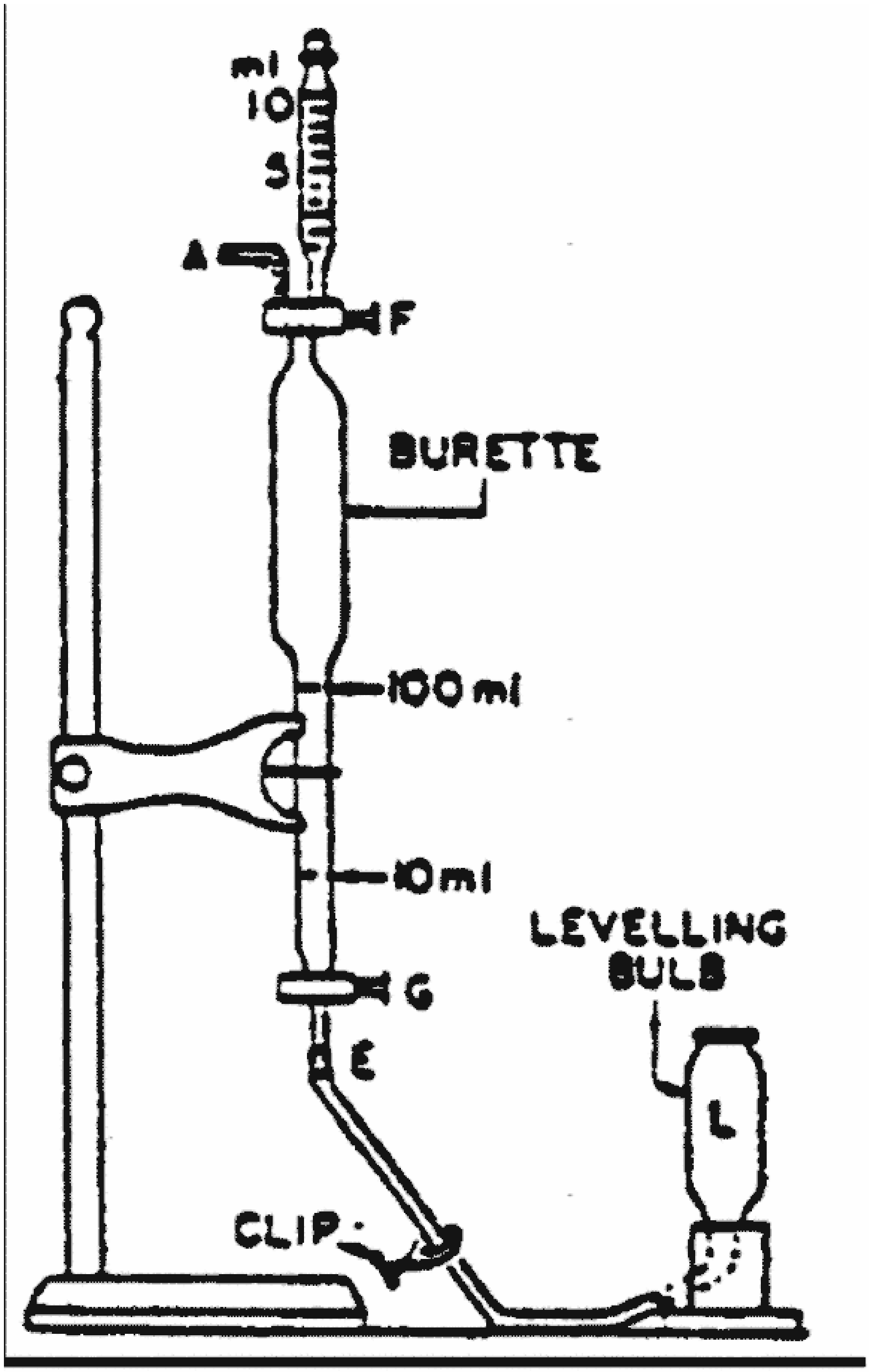

Figure 1. Tutwiler burette (lettered items mentioned in text).

§ 60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (i) of this section. The initial compliance period begins on October 15, 2012, or upon initial startup, whichever is later, and ends no later than one year after the initial startup date for your affected facility or no later than one year after October 15, 2012. The initial compliance period may be less than one full year.

(a) To achieve initial compliance with the standards for each well completion operation conducted at your gas well affected facility you must comply with paragraphs (a)(1) through (a)(4) of this section.

(1) You must submit the notification required in § 60.5420(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in § 60.5420(b).

(3) You must maintain a log of records as specified in § 60.5420(c)(1)(i) through (iv) for each well completion operation conducted during the initial compliance period.

(4) For each gas well affected facility subject to both § 60.5375(a)(1) and (3), as an alternative to retaining the records specified in § 60.5420(c)(1)(i) through (iv), you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each gas well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

(b)

(1) To achieve initial compliance with standards for your centrifugal compressor affected facility you must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required by § 60.5380 and as demonstrated by the requirements of § 60.5413.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411(b) that is connected through a closed vent system that meets the requirements of § 60.5411(a) and is routed to a control device that meets the conditions specified in § 60.5412(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(3) You must conduct an initial performance test as required in § 60.5413 within 180 days after initial startup or by October 15, 2012, whichever is later, and you must comply with the continuous compliance requirements in § 60.5415(b)(1) through (3).

(4) You must conduct the initial inspections required in § 60.5416(a) and (b).

(5) You must install and operate the continuous parameter monitoring systems in accordance with § 60.5417(a) through (g), as applicable.

(6) [Reserved]

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in § 60.5420(b)(3) for each centrifugal compressor affected facility.

(8) You must maintain the records as specified in § 60.5420(c)(2).

(c) To achieve initial compliance with the standards for each reciprocating compressor affected facility you must comply with paragraphs (c)(1) through (4) of this section.

(1) If complying with § 60.5385(a)(1) or (2), during the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

(2) If complying with § 60.5385(a)(3), you must operate the rod packing emissions collection system under negative pressure and route emissions to a process through a closed vent system that meets the requirements of § 60.5411(a).

(3) You must submit the initial annual report for your reciprocating compressor as required in § 60.5420(b).

(4) You must maintain the records as specified in § 60.5420(c)(3) for each reciprocating compressor affected facility.

(d) To achieve initial compliance with emission standards for your pneumatic controller affected facility you must comply with the requirements specified in paragraphs (d)(1) through (6) of this section, as applicable.

(1) You must demonstrate initial compliance by maintaining records as specified in § 60.5420(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than 6 standard cubic feet of gas per hour is required as specified in § 60.5390(a).

(2) You own or operate a pneumatic controller affected facility located at a natural gas processing plant and your pneumatic controller is driven by a gas other than natural gas and therefore emits zero natural gas.

(3) You own or operate a pneumatic controller affected facility located between the wellhead and a natural gas processing plant and the manufacturer's design specifications indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(4) You must tag each new pneumatic controller affected facility according to the requirements of § 60.5390(b)(2) or (c)(2).

(5) You must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for your pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of § 60.5420(b).

(6) You must maintain the records as specified in § 60.5420(c)(4) for each pneumatic controller affected facility.

(e) [Reserved]

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400.

(g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

(1) To determine compliance with the standards for SO_2 specified in § 60.5405(a), during the initial performance test as required by § 60.8, the minimum required sulfur dioxide emission reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406(c)(1).

(3) You have submitted the results of paragraphs (g)(1) and (2) of this section in the initial annual report submitted for your sweetening unit affected facilities at onshore natural gas processing plants.

(h) For each storage vessel affected facility, you must comply with paragraphs (h)(1) through (5) of this section. For a Group 1 storage vessel affected facility, you must demonstrate initial compliance by April 15, 2015, except as otherwise provided in paragraph (i) of this section. For a Group 2 storage vessel affected facility, you must demonstrate initial compliance by April 15, 2014, or within 60 days after startup, whichever is later.

(1) You must determine the potential VOC emission rate as specified in § 60.5365(e).

(2) You must reduce VOC emissions in accordance with § 60.5395(d).

(3) If you use a control device to reduce emissions, or if you route emissions to a process, you must demonstrate initial compliance by meeting the requirements in § 60.5395(e).

(4) You must submit the information required for your storage vessel affected facility as specified in § 60.5420(b).

(5) You must maintain the records required for your storage vessel affected facility, as specified in § 60.5420(c)(5) through (8) and § 60.5420(c)(12) and (13) for each storage vessel affected facility.

(i) For each Group 1 storage vessel affected facility, you must submit the notification specified in § 60.5395(b)(2) with the initial annual report specified in § 60.5420(b)(6).

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58437, Sept. 23, 2013; 79 FR 79038, Dec. 31, 2014; 81 FR 35896, June 3, 2016]

§ 60.5411 What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing materials from storage vessels, reciprocating compressors and centrifugal compressor wet seal degassing systems?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your storage vessel, reciprocating compressor or centrifugal compressor affected facility.

(a) ***Closed vent system requirements for reciprocating compressors and for centrifugal compressor wet seal degassing systems.***

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the reciprocating compressor rod packing emissions collection system or the wet seal fluid degassing system to a control device or to a process that meets the requirements specified in § 60.5412(a) through (c).

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by § 60.5416(b).

(3) You must meet the requirements specified in paragraphs (a)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

(i) Except as provided in paragraph (a)(3)(ii) of this section, you must comply with either paragraph (a)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in § 60.5416(a)(4) and either sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (a)(3)(i) of this section.

(b) ***Cover requirements for storage vessels and centrifugal compressor wet seal degassing systems.***

(1) The cover and all openings on the cover (*e.g.,* access hatches, sampling ports, pressure relief valves and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(2) Each cover opening shall be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed-vent system designed and operated in accordance with the requirements of paragraph (a) or (c) of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(c) ***Closed vent system requirements for storage vessel affected facilities using a control device or routing emissions to a process.***

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device that meets the requirements specified in § 60.5412(c) and (d), or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections. Each closed vent system that routes emissions to a process must be operational 95 percent of the year or greater.

(3) You must meet the requirements specified in paragraphs (c)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (c)(3)(ii) of this section, you must comply with either paragraph (c)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere and that either sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (c)(3)(i) of this section.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58438, Sept. 23, 2013; 79 FR 79038, Dec. 31, 2014; 81 FR 35896, June 3, 2016]

§ 60.5412 What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your storage vessel or centrifugal compressor affected facility.

(a) Each control device used to meet the emission reduction standard in § 60.5380(a)(1) for your centrifugal compressor affected facility must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a control device model tested under § 60.5413(d), which meets the criteria in § 60.5413(d)(11) and § 60.5413(e).

(1) Each combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

(i) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413.

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 60.5413.

(iii) You must operate at a minimum temperature of 760 °C for a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under § 60.5413.

(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413. As an alternative to the performance testing requirements, you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of § 60.5413(c).

(3) You must design and operate a flare in accordance with the requirements of § 60.5413.

(b) You must operate each control device installed on your centrifugal compressor affected facility in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system affected facility, as required under § 60.5380(a), through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of § 60.5417(a) through (g), you must demonstrate compliance according to the requirements of § 60.5415(b)(2), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) or (d)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) or (2) of this section.

(1) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to § 60.5413(c)(2) or (3) or according to the design required in paragraph (d)(2) of this section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in § 60.5420(c)(10) and (12).

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vii) of this section.

(i) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a thermal treatment unit equipped with and operating air emission controls in accordance with this section.

(iii) Regenerate or reactivate the spent carbon in a thermal treatment unit equipped with and operating organic air emission controls in accordance with an emissions standard for VOC under another subpart in 40 CFR part 60 or this part.

(iv) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart O.

(v) Burn the spent carbon in a hazardous waste incinerator which you have designed and operated in accordance with the requirements of 40 CFR part 265, subpart O.

(vi) Burn the spent carbon in a boiler or industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vii) Burn the spent carbon in a boiler or industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(d) Each control device used to meet the emission reduction standard in § 60.5395(d) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (3) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under § 60.5413(d), which meets the criteria in § 60.5413(d)(11) and § 60.5413(e).

(1) Each enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed to reduce the mass content of VOC emissions by 95.0 percent or greater. Each flare must be designed and operated in accordance with the requirements of § 60.5413(a)(1). You must follow the requirements in paragraphs (d)(1)(i) through (iv) of this section.

(i) Ensure that each enclosed combustion device is maintained in a leak free condition.

(ii) Install and operate a continuous burning pilot flame.

(iii) Operate the enclosed combustion device with no visible emissions, except for periods not to exceed a total of one minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A, visual observation as described in this paragraph.

(iv) Each enclosed combustion control device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (d)(1)(iv)(A) through (D) of this section.

(A) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413.

(B) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 60.5413.

(C) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under § 60.5413, that combustion zone temperature is an indicator of destruction efficiency.

(D) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(3) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58438, Sept. 23, 2013; 79 FR 79039, Dec. 31, 2014; 81 FR 35897, June 3, 2016]

§ 60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your centrifugal compressor affected facility. You must demonstrate that a control device achieves the performance requirements of § 60.5412(a) using the performance test methods and procedures specified in this section. For condensers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion device performance tests conducted by the manufacturer applicable to both storage vessel and centrifugal compressor affected facilities.

(a) ***Performance test exemptions.*** You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) A flare that is designed and operated in accordance with § 60.18(b). You must conduct the compliance determination using Method 22 at 40 CFR part 60, appendix A-7, to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; or you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H.

(5) A hazardous waste incinerator for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 264, subpart O; or you have certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

(6) A performance test is waived in accordance with § 60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of § 60.5412(a) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) ***Test methods and procedures.*** You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of § 60.5412(a). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section.

(1) You must use Method 1 or 1A at 40 CFR part 60, appendix A-1, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device, and at the outlet of the final control device, to determine compliance with the control device percent reduction requirement specified in § 60.5412(a)(1)(i) or (a)(2).

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with the enclosed combustion device total TOC concentration limit specified in § 60.5412(a)(1)(ii).

(2) You must determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D at 40 CFR part 60, appendix A-2, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in § 60.5412(a)(1)(i) or (a)(2), you must use Method 25A at 40 CFR part 60, appendix A-7. You must use the procedures in paragraphs (b)(3)(i) through (iv) of this section to calculate percent reduction efficiency.

(i) For each run, you must take either an integrated sample or a minimum of four grab samples per hour. 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) You must compute the mass rate of TOC (minus methane and ethane) using the equations and procedures specified in paragraphs (b)(3)(ii)(A) and (B) of this section.

(A) You must use the following equations:

$$E_i = K_2\left(\sum_{j=1}^{n} C_{ij}M_{ij}\right)Q_i$$

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj}M_{oj}\right)Q_o$$

Where:

E_i, E_o = Mass rate of TOC (minus methane and ethane) at the inlet and outlet of the control device, respectively, dry basis, kilogram per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 °C.

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.

M_{ij}, M_{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 = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

n = Number of components in sample.

(B) When calculating the TOC mass rate, you must sum all organic compounds (minus methane and ethane) measured by Method 25A at 40 CFR part 60, appendix A-7 using the equations in paragraph (b)(3)(ii)(A) of this section.

(iii) You must calculate the percent reduction in TOC (minus methane and ethane) as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

Where:

R_{cd} = Control efficiency of control device, percent.

E_i = Mass rate of TOC (minus methane and ethane) at the inlet to the control device as calculated under paragraph (b)(3)(ii) of this section, kilograms TOC per hour or kilograms HAP per hour.

E_o = Mass rate of TOC (minus methane and ethane) at the outlet of the control device, as calculated under paragraph (b)(3)(ii) of this section, kilograms TOC per hour per hour.

(iv) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC (minus methane and ethane) across the device by comparing the TOC (minus methane and ethane) in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) exiting the device, respectively.

(4) You must use Method 25A at 40 CFR part 60, appendix A-7 to measure TOC (minus methane and ethane) to determine compliance with the enclosed combustion device total VOC concentration limit specified in § 60.5412(a)(1)(ii). You must calculate parts per million by volume concentration and correct to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) For each run, you must take either an integrated sample or a minimum of four grab samples per hour. 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) You must calculate the TOC concentration for each run as follows:

$$C_{TOC} = \sum_{i=1}^{x} \frac{\left(\sum_{j=i}^{n} C_{ji}\right)}{x}$$

Where:
C_{TOC} = Concentration of total organic compounds minus methane and ethane, dry basis, parts per million by volume.
C_{ji} = Concentration of sample component j of sample i, dry basis, parts per million by volume.
n = Number of components in the sample.
x = Number of samples in the sample run.

(iii) You must correct the TOC concentration to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B at 40 CFR part 60, appendix A, ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2d}}\right)$$

Where:
C_c = TOC concentration corrected to 3 percent oxygen, dry basis, parts per million by volume.
C_m = TOC concentration, dry basis, parts per million by volume.
$\%O_{2d}$ = Concentration of oxygen, dry basis, percent by volume.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in § 60.5420(b)(7).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in § 60.5420(b)(7). Combustion control devices meeting the criteria in either paragraph (b)(5)(ii)(A) or (B) of this section are not required to conduct periodic performance tests.

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section.

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in § 60.5412(a)(1)(ii) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level.

(c) ***Control device design analysis to meet the requirements of § 60.5412(a).***

(1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and must 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.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, 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 the carbon beds, design total regeneration stream 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 the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for

the carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems will incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

(d) ***Performance testing for combustion control devices—manufacturers' performance test.***

(1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three one-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90-100 percent of maximum design rate (fixed rate).

(ii) 70-100-70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30-70-30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0-30-0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) through (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with Method 2A, 40 CFR part 60, appendix A-1, (or other approved procedure) to measure inlet gas flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet flow rate must be determined using Method 2A, 40 CFR part 60, appendix A-1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) through (ii) of this section.

(i) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of each test run, and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945-03.

(B) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945-03.

(C) Higher heating value using ASTM D3588-98 or ASTM D4891-89.

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) through (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using Method 1, 40 CFR part 60, appendix A-1 for determining flow measurement traverse point location, and Method 2, 40 CFR part 60, appendix A-1 for measuring duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the Method 4, 40 CFR part 60, appendix A-3, moisture test following the procedure specified in (d)(7)(i)(A) through (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC-TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) through (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC-TCD calibration procedure in Method 3C, 40 CFR part 60, appendix A, must be modified by using EPA Alt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane, and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using Method 4, 40 CFR part 60, appendix A-3. Traverse both ports with the Method 4, 40 CFR part 60, appendix A-3, sampling train during each test run. Ambient air must not be introduced into the Method 3C, 40 CFR part 60, appendix A-2, integrated bag sample during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B, 40 CFR part 60, appendix A, equation 3B-1.

(8) Carbon monoxide must be determined using Method 10, 40 CFR part 60, appendix A. Run the test simultaneously with Method 25A, 40 CFR part 60, appendix A-7 using the same sampling points. An instrument range of 0-10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified by in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using Method 25A, 40 CFR part 60, appendix A-7, except that the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test run.

(ii) A valid test must consist of three Method 25A, 40 CFR part 60, appendix A-7, tests, each no less than 60 minutes in duration.

(iii) A 0-10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0-30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—“EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,” (incorporated by reference as specified in § 60.17).

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO_2, as measured by Method 3C, 40 CFR part 60, appendix A-2. You must use the following equation for this diluent concentration correction:

$$Ccorr = Cmeas\left(\frac{3}{CO_{2meas}}\right)$$

Where:

C_{meas} = The measured concentration of the pollutant.
CO_{2meas} = The measured concentration of the CO_2 diluent.
3 = The corrected reference concentration of CO_2 diluent.
C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using Method 22, 40 CFR part 60, appendix A. The test must be per during each test run. A digital color photograph of the exhaust point, taken from the position of the observe date and time, must be taken once per test run and the 12 photos included in the test report specified in pa section.

(11) ***Performance test criteria.***

(i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this must be reported in the test report required by paragraph (d)(12) of this section.

(A) Method 22, 40 CFR part 60, appendix A, results under paragraph (d)(10) of this section with no in emissions.

(B) Average Method 25A, 40 CFR part 60, appendix A, results under paragraph (d)(9) of this section e ppmvw THC as propane corrected to 3.0 percent CO_2.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 to 3.0 percent CO_2.

(D) Excess combustion air determined under paragraph (d)(7) of this section equal to or greater than

(ii) The manufacturer must determine a maximum inlet gas flow rate which must not be exceeded for eac to achieve the criteria in paragraph (d)(11)(iii) of this section. The maximum inlet gas flow rate must b report required by paragraph (d)(12) of this section.

(iii) A control device meeting the criteria in paragraph (d)(11)(i)(A) through (D) of this section must demon efficiency of 95 percent for VOC regulated under this subpart.

(12) The owner or operator of a combustion control device model tested under this paragraph must submit the paragraphs (d)(12)(i) through (vi) in the test report required by this section in accordance with § 60.5420(b

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this paramete

(F) Excess combustion air range.

(G) Flame arrestor(s).

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) ***Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.*** This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance requirements in (d)(11) of this section by installing a device tested under paragraph (d) of this section and complying with the criteria specified in paragraphs (e)(1) through (7) of this section.

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass an EPA Method 22, 40 CFR part 60, appendix A, visual observation as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via email to *Oil__and__Gas__PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/*.

(7) Ensure that each enclosed combustion device is maintained in a leak free condition.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58439, Sept. 23, 2013; 79 FR 79039, Dec. 31, 2014; 81 FR 35897, June 3, 2016]

§ 60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

(a) For each gas well affected facility, you must demonstrate continuous compliance by submitting the reports required by § 60.5420(b) and maintaining the records for each completion operation specified in § 60.5420(c)(1).

(b) For each centrifugal compressor affected facility, you must demonstrate continuous compliance according to paragraphs (b)(1) through (3) of this section.

(1) You must reduce VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of § 60.5412(a) using the procedures specified in paragraphs (b)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in § 60.5412(a)(2), you must demonstrate compliance according to paragraph (b)(2)(viii) of this section. You may switch between compliance with paragraphs (b)(2)(i) through (vii) of this section and compliance with paragraph (b)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, as required in § 60.5420(b), following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of § 60.5417(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with § 60.5417(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (b)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (b)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in § 60.5413(d), compliance with the operating parameter limit is achieved when the criteria in § 60.5413(e) are met.

(iv) You must operate the continuous monitoring system required in § 60.5417 at all times the affected source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of § 60.5412(a) and you demonstrate compliance using the test procedures specified in § 60.5413(b), you must comply with paragraphs (b)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(C) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A, visual observation as described in paragraph (b)(2)(vii)(B) of this section.

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in § 60.5412(a)(2), you must demonstrate compliance using the procedures in paragraphs (b)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to § 60.5417(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with § 60.5417(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (b)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (b)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (b)(2)(viii)(D)(*1*) and (*2*) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (b)(2)(viii)(C) of this section.

(*1*) After the compliance dates specified in § 60.5370, if you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation after the compliance dates. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(*2*) After 120 days and no more than 364 days of operation after the compliance date specified in § 60.5370, you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement, if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (b)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(3) You must submit the annual report required by 60.5420(b) and maintain the records as specified in § 60.5420(c)(2).

(c) For each reciprocating compressor affected facility complying with § 60.5385(a)(1) or (2), you must demonstrate continuous compliance according to paragraphs (c)(1) through (3) of this section. For each reciprocating compressor affected facility complying with § 60.5385(a)(3), you must demonstrate continuous compliance according to paragraph (c)(4) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) You must submit the annual report as required in § 60.5420(b) and maintain records as required in § 60.5420(c)(3).

(3) You must replace the reciprocating compressor rod packing before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(4) You must operate the rod packing emissions collection system under negative pressure and continuously comply with the closed vent requirements in § 60.5416(a) and (b).

(d) For each pneumatic controller affected facility, you must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

(1) You must continuously operate the pneumatic controllers as required in § 60.5390(a), (b), or (c).

(2) You must submit the annual report as required in § 60.5420(b).

(3) You must maintain records as required in § 60.5420(c)(4).

(e) You must demonstrate continuous compliance according to paragraph (e)(3) of this section for each storage vessel affected facility, for which you are using a control device or routing emissions to a process to meet the requirement of § 60.5395(d)(1).

(1)-(2) [Reserved]

(3) For each storage vessel affected facility, you must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) You must reduce VOC emissions as specified in § 60.5395(d).

(ii) For each control device installed to meet the requirements of § 60.5395(d), you must demonstrate continuous compliance with the performance requirements of § 60.5412(d) for each storage vessel affected facility using the procedure specified in paragraph (e)(3)(ii)(A) and either (e)(3)(ii)(B) or (e)(3)(ii)(C) of this section.

(A) You must comply with § 60.5416(c) for each cover and closed vent system.

(B) You must comply with § 60.5417(h) for each control device.

(C) Each closed vent system that routes emissions to a process must be operated as specified in § 60.5411(c)(2).

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400.

(g) For each sweetening unit affected facility at onshore natural gas processing plants, you must demonstrate continuous compliance with the standards for SO_2 specified in § 60.5405(b) according to paragraphs (g)(1) and (2) of this section.

(1) The minimum required SO_2 emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406(c)(1).

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58442, Sept. 23, 2013; 79 FR 79039, Dec. 31, 2014; 81 FR 35897, June 3, 2016]

§ 60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel, centrifugal compressor and reciprocating compressor affected facilities?

For each closed vent system or cover at your storage vessel, centrifugal compressor and reciprocating compressor affected facility, you must comply with the applicable requirements of paragraphs (a) through (c) of this section.

(a) ***Inspections for closed vent systems and covers installed on each centrifugal compressor or reciprocating compressor affected facility.*** Except as provided in paragraphs (b)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) and (ii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(ii) Conduct annual inspections according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(3) For each cover, you must meet the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) You must initially conduct the inspections specified in paragraph (a)(3)(i) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (b)(11) and (12) of this section. You must maintain records of the inspection results as specified in § 60.5420(c)(7).

(4) For each bypass device, except as provided for in § 60.5411, you must meet the requirements of paragraphs (a)(4)(i) or (ii) of this section.

(i) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to § 60.5420(c)(8).

(b) ***No detectable emissions test methods and procedures.*** If you are required to conduct an inspection of a closed vent system or cover at your centrifugal compressor or reciprocating compressor affected facility as specified in paragraphs (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21 at 40 CFR part 60, appendix A-7.

(2) The detection instrument must meet the performance criteria of Method 21 at 40 CFR part 60, appendix A-7, except that the instrument response factor criteria in section 3.1.2(a) of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 at 40 CFR part 60, appendix A-7.

(4) Calibration gases must be as specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 at 40 CFR part 60, appendix A-7.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (b)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 at 40 CFR part 60, appendix A-7, except the instrument response factor criteria in section 3.1.2(a) of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (b)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (b)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (b)(7) of this section is less than 500 parts per million by volume.

(9) ***Repairs.*** In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (b)(9)(i) and (ii) of this section, except as provided in paragraph (b)(10) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) ***Delay of repair.*** Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) ***Unsafe to inspect requirements.*** You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (b)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1), (2), or (3) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) ***Difficult to inspect requirements.*** You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (b)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) ***Records.*** Records shall be maintained as specified in this section and in § 60.5420(c)(9).

(c) ***Cover and closed vent system inspections for storage vessel affected facilities.*** If you install a control device or route emissions to a process, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (c)(1) of this section, inspect each cover according to the procedures and schedule specified in paragraph (c)(2) of this section, and inspect each bypass device according to the procedures of paragraph (c)(3) of this section. You must also comply with the requirements of (c)(4) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection at least once every calendar month as specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(2) For each cover, you must conduct inspections at least once every calendar month as specified in paragraphs (c)(2)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420(c)(7).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices.

In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(3) For each bypass device, except as provided for in § 60.5411(c)(3)(ii), you must meet the requirements of paragraphs (c)(3)(i) or (ii) of this section.

(i) You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, or initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420(c)(8).

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections and records of each time the key is checked out, if applicable, according to § 60.5420(c)(8).

(4) ***Repairs.*** In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (c)(4)(i) through (iii) of this section, except as provided in paragraph (c)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 30 calendar days after the leak is detected.

(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) ***Delay of repair.*** Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) ***Unsafe to inspect requirements.*** You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (c)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (c)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) ***Difficult to inspect requirements.*** You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (c)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58443, Sept. 23, 2013; 79 FR 79039, Dec. 31, 2014; 81 FR 35897, June 3, 2016]

§ 60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your storage vessel or centrifugal compressor affected facility.

(a) For each control device used to comply with the emission reduction standard for centrifugal compressor affected facilities in § 60.5380, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with § 60.5412(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or is used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in either paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 60.5413 that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.8 °C, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater.

(vii) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a performance test performed as specified in § 60.5413(b). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under § 60.5413(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section.

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better. The flow rate at the inlet to the combustion device must not exceed the maximum or minimum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the control device.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. The monitor must meet the requirements of Performance Specification 8 or 9 of 40 CFR part 60, appendix B. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(3) A continuous monitoring system that measures operating parameters other than those specified in paragraph (d)(1) or (2) of this section, upon approval of the Administrator as specified in § 60.13(i).

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 60.5412(a). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of § 60.5413(b) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412(a), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of § 60.5413(c) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412(a), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under § 60.5413(d) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412(a), then your control device inlet gas flow rate must not exceed the maximum or minimum inlet gas flow rate determined by the manufacturer.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of § 60.5413(b) to demonstrate that the condenser achieves the applicable performance requirements in § 60.5412(a), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of § 60.5413(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in § 60.5412(a), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (g)(6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section.

(2) If you meet § 60.5412(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 60.5415(e)(8)(iv) is less than 95.0 percent.

(3) If you meet § 60.5412(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in § 60.5415(e)(8)(iv)(A) or (B) is less than 90.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraphs (g)(5)(i) and (ii) of this section are met.

(i) For each bypass line subject to § 60.5411(a)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to § 60.5411(a)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under § 60.5413(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under § 60.5413(d).

(ii) Failure of the quarterly visible emissions test conducted under § 60.5413(e)(3) occurs.

(h) For each control device used to comply with the emission reduction standard in § 60.5395(d)(1) for your storage vessel affected facility, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(3) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with § 60.5413(d)(2) through (10), which meets the criteria in § 60.5413(d)(11), the reporting requirement in § 60.5413(d)(12), and meet the continuous compliance requirement in § 60.5413(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (h)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22, 40 CFR part 60, appendix A. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

(iii) Conduct olfactory, visual and auditory inspections of all equipment associated with the combustion device to ensure system integrity.

(iv) For any absence of pilot flame, or other indication of smoking or improper equipment operation (*e.g.,* visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (h)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified in § 60.5420(c)(13).

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58443, Sept. 23, 2013]

§ 60.5420 What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications according to paragraphs (a)(1) and (2) of this section if you own or operate one or more of the affected facilities specified in § 60.5365 that was constructed, modified, or reconstructed during the reporting period.

(1) If you own or operate a gas well, pneumatic controller, centrifugal compressor, reciprocating compressor or storage vessel affected facility you are not required to submit the notifications required in § 60.7(a)(1), (3), and (4).

(2)

(i) If you own or operate a gas well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the API well number, the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

(ii) If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

(b) Reporting requirements. You must submit annual reports containing the information specified in paragraphs (b)(1) through (6) of this section to the Administrator and performance test reports as specified in paragraph (b)(7) or (8) of this section. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to § 60.5410. Subsequent annual reports are due no later than same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (6) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) The company name and address of the affected facility.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(2) For each gas well affected facility, the information in paragraphs (b)(2)(i) through (ii) of this section.

(i) Records of each well completion operation as specified in paragraph (c)(1)(i) through (iv) of this section for each gas well affected facility conducted during the reporting period. In lieu of submitting the records specified in paragraph (c)(1)(i) through (iv), the owner or operator may submit a list of the well completions with hydraulic fracturing completed during the reporting period and the records required by paragraph (c)(1)(v) of this section for each well completion.

(ii) Records of deviations specified in paragraph (c)(1)(ii) of this section that occurred during the reporting period.

(3) For each centrifugal compressor affected facility, the information specified in paragraphs (b)(3)(i) and (ii) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(ii) Records of deviations specified in paragraph (c)(2) of this section that occurred during the reporting period.

(iii) If required to comply with § 60.5380(a)(1), the records specified in paragraphs (c)(6) through (11) of this section.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) through (ii) of this section.

(i) The cumulative number of hours of operation or the number of months since initial startup, since October 15, 2012, or since the previous reciprocating compressor rod packing replacement, whichever is later.

(ii) Records of deviations specified in paragraph (c)(3)(iii) of this section that occurred during the reporting period.

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (iii) of this section.

(i) An identification of each pneumatic controller constructed, modified or reconstructed during the reporting period, including the identification information specified in § 60.5390(b)(2) or (c)(2).

(ii) If applicable, documentation that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.

(iii) Records of deviations specified in paragraph (c)(4)(v) of this section that occurred during the reporting period.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (vii) of this section.

(i) An identification, including the location, of each storage vessel affected facility for which construction, modification or reconstruction commenced during the reporting period. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the VOC emission rate determination according to § 60.5365(e) for each storage vessel that became an affected facility during the reporting period or is returned to service during the reporting period.

(iii) Records of deviations specified in paragraph (c)(5)(iii) of this section that occurred during the reporting period.

(iv) You must submit a notification identifying each Group 1 storage vessel affected facility in your initial annual report. You must include the location of the storage vessel, in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) A statement that you have met the requirements specified in § 60.5410(h)(2) and (3).

(vi) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in § 60.5395(f)(1)(ii), including the date the storage vessel affected facility was removed from service.

(vii) You must identify each storage vessel affected facility returned to service during the reporting period as specified in § 60.5395(f)(3), including the date the storage vessel affected facility was returned to service.

(7)

(i) Within 60 days after the date of completing each performance test (see § 60.8 of this part) as required by this subpart, except testing conducted by the manufacturer as specified in § 60.5413(d), you must submit the results of the performance tests required by this subpart to the EPA as follows. You must use the latest version of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*) existing at the time of the performance test to generate a submission package file, which documents the performance test. You must then submit the file generated by the ERT through the EPA's Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed by logging in to the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). Only data collected using test methods supported by the ERT as listed on the ERT Web site are subject to this requirement for submitting reports electronically. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test to the Administrator at the appropriate address listed in § 60.4.

(ii) All reports, except as specified in paragraph (b)(8) of this section, required by this subpart not subject to the requirements in paragraph (a)(2)(i) of this section must be sent to the Administrator at the appropriate address listed in § 60.4 of this part. The Administrator or the delegated authority may request a report in any form suitable for the specific case (e.g., by commonly used electronic media such as Excel spreadsheet, on CD or hard copy).

(8) For enclosed combustors tested by the manufacturer in accordance with § 60.5413(d), an electronic copy of the performance test results required by § 60.5413(d) shall be submitted via email to *Oil____and____Gas____PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/*.

(c) ***Recordkeeping requirements.*** You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (14) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years.

(1) The records for each gas well affected facility as specified in paragraphs (c)(1)(i) through (v) of this section.

(i) Records identifying each well completion operation for each gas well affected facility;

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375.

(iii) Records required in § 60.5375(b) or (f) for each well completion operation conducted for each gas well affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) and (B) of this section.

(A) For each gas well affected facility required to comply with the requirements of § 60.5375(a), you must record: The location of the well; the API well number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in § 60.5375(a)(1)(i); the date and time of each occurrence of returning to the initial flowback stage under § 60.5375(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery to the flow line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours of time.

(B) For each gas well affected facility required to comply with the requirements of § 60.5375(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the flow line.

(iv) For each gas well facility for which you claim an exception under § 60.5375(a)(3), you must record: The location of the well; the API well number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each gas well affected facility required to comply with both § 60.5375(a)(1) and (3), if you are using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, you must retain the records of the digital photograph as specified in § 60.5410(a)(4).

(2) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in § 60.5380.

(3) For each reciprocating compressors affected facility, you must maintain the records in paragraphs (c)(3)(i) through (iii) of this section.

(i) Records of the cumulative number of hours of operation or number of months since initial startup or October 15, 2012, or the previous replacement of the reciprocating compressor rod packing, whichever is later.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in § 60.5385(a)(3).

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in § 60.5385.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (v) of this section.

(i) Records of the date, location and manufacturer specifications for each pneumatic controller constructed, modified or reconstructed.

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.

(iii) If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.

(iv) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(v) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in § 60.5390.

(5) Except as specified in paragraph (c)(5)(v) of this section, for each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (iv) of this section.

(i) If required to reduce emissions by complying with § 60.5395(d)(1), the records specified in §§ 60.5420(c)(6) through (8), 60.5416(c)(6)(ii), and 60.6516(c)(7)(ii) of this subpart.

(ii) Records of each VOC emissions determination for each storage vessel affected facility made under § 60.5365(e) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in §§ 60.5395, 60.5411, 60.5412, and 60.5413, as applicable.

(iv) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships), records indicating the number of consecutive days that the vessel is located at a site in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment. If a storage vessel is removed from a site and, within 30 days, is either returned to or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(v) You must maintain records of the identification and location of each storage vessel affected facility.

(6) Records of each closed vent system inspection required under § 60.5416(a)(1) and (2) for centrifugal or reciprocating compressors or § 60.5416(c)(1) for storage vessels.

(7) A record of each cover inspection required under § 60.5416(a)(3) for centrifugal or reciprocating compressors or § 60.5416(c)(2) for storage vessels.

(8) If you are subject to the bypass requirements of § 60.5416(a)(4) for centrifugal or reciprocating compressors or § 60.5416(c)(3) for storage vessels, a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(9) If you are subject to the closed vent system no detectable emissions requirements of § 60.5416(b) for centrifugal or reciprocating compressors, a record of the monitoring conducted in accordance with § 60.5416(b).

(10) For each centrifugal compressor affected facility, records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5413(c)(2) or (3)) and records of each carbon replacement as specified in § 60.5412(c)(1).

(11) For each centrifugal compressor subject to the control device requirements of § 60.5412(a), (b), and (c), records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(12) For each carbon adsorber installed on storage vessel affected facilities, records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5412(d)(2)) and records of each carbon replacement as specified in § 60.5412(c)(1).

(13) For each storage vessel affected facility subject to the control device requirements of § 60.5412(c) and (d), you must maintain records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in § 60.5417(h). You must maintain records of EPA Method 22, 40 CFR part 60, appendix A, section 11 results, which include: company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in EPA Method 22, 40 CFR part 60, appendix A. Manufacturer's operating instructions, procedures and maintenance schedule must be available for inspection.

(14) A log of records as specified in §§ 60.5412(d)(1)(iii) and 60.5413(e)(4) for all inspection, repair and maintenance activities for each control device failing the visible emissions test.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58445, Sept. 23, 2013; 79 FR 79039, Dec. 31, 2014; 81 FR 35897, June 3, 2016; 85 FR 57069, Sept. 14, 2020; 89 FR 17036, Mar. 8, 2024]

§ 60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of § 60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of § 60.5401(b)(1) of this subpart.

(1) When each leak is detected as specified in § 60.5401(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in § 60.5401(b)(2), the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) "Above 500 ppm" if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.

(v) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of § 60.482-4a(a). The designation of equipment subject to the provisions of § 60.482-4a(a) must be signed by the owner or operator.

§ 60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of § 60.487a(a), (b), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii).

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in § 60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of § 60.5401(b) except for those pressure relief devices designated for no detectable emissions under the provisions of § 60.482-4a(a) and those pressure relief devices complying with § 60.482-4a(c).

(c) An owner or operator must include the following information in all semiannual reports in addition to the information required in § 60.487a(c)(2)(i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in § 60.5401(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in § 60.5401(b)(3).

§ 60.5423 What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

(a) You must retain records of the calculations and measurements required in §§ 60.5405(a) and (b) and 60.5407(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under § 60.7(d) of the General Provisions.

(b) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. For the purpose of these reports, excess emissions are defined as:

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of § 60.5407(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of § 60.5407(b)(2). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less that 2 LT/D of H_2S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H_2S expressed as sulfur.

(d) If you elect to comply with § 60.5407(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H_2S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state.

§ 60.5425 What part of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

§ 60.5430 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(1) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where

(i) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$A = Y \times (B \div 100)$;

(ii) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is 2011 minus the year of construction; and

(iii) The applicable basic annual asset guideline repair allowance, B, is 4.5.

(2) [Reserved]

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including but not limited to general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

City gate means the delivery point at which natural gas is transferred from a transmission pipeline to the local gas utility.

Collection system means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

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

Continuous bleed means a continuous flow of pneumatic supply natural gas to the process control device (e.g., level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).

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

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(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 limit, 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.

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Equipment, as used in the standards and requirements in this subpart relative to the equipment leaks of VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Flow line means a pipeline used to transport oil and/or gas to a processing facility, a mainline pipeline, re-injection, or routed to a process or other useful purpose.

Flowback means the process of allowing fluids and entrained solids to flow from a natural gas well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term *flowback* also means the fluids and entrained solids that emerge from a natural gas well during the flowback process. The *flowback period* begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The *flowback period* ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Gas well or natural gas well means an onshore well drilled principally for production of natural gas.

Group 1 storage vessel means a storage vessel, as defined in this section, for which construction, modification or reconstruction has commenced after August 23, 2011, and on or before April 12, 2013.

Group 2 storage vessel means a storage vessel, as defined in this section, for which construction, modification or reconstruction has commenced after April 12, 2013, and on or before September 18, 2015.

Hydraulic fracturing or refracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485a(e) or § 60.5401(g)(2) of this part.

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Initial flowback stage means the period during a well completion operation which begins at the onset of flowback and ends at the separation flowback stage.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Intermittent/snap-action pneumatic controller means a pneumatic controller that vents non-continuously.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Low pressure gas well means a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the true vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.

Maximum average daily throughput means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

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.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

Recovered gas means gas recovered through the separation process during flowback.

Recovered liquids means any crude oil, condensate or produced water recovered through the separation process during flowback.

Reduced emissions completion means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2).

Removed from service means that a storage vessel affected facility has been physically isolated and disconnected from the process for a purpose other than maintenance in accordance with § 60.5395(f)(1).

Responsible official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representatives is approved in advance by the permitting authority;

(2) For a partnership or sole proprietorship: A general partner or the proprietor, respectively;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Returned to service means that a Group 1 or Group 2 storage vessel affected facility that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel affected facility; or

(2) Installed in any location covered by this subpart and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly 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 regulated materials and/or incorporated into a product; and/or recovered.

Salable quality gas means natural gas that meets the flow line or collection system operator specifications, regardless of whether such gas is sold.

Separation flowback stage means the period during a well completion operation when it is technically feasible for a separator to function. The *separation flowback stage* ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.

Startup of production means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of § 60.5395(f) until such time as such tank or other vessel has been returned to service. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of § 60.5395(f) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by § 60.5420(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

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

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A to part 60 of this chapter.

Total SO2 equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO_2 to the quantity of SO_2 that would be obtained if all reduced sulfur compounds were converted to SO_2 (ppmv or kg/dscm (lb/dscf)).

Underground storage vessel means a storage vessel stored below ground.

Well means an oil or gas well, a hole drilled for the purpose of producing oil or gas, or a well into which fluids are injected.

Well completion means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a gas well affected facility.

Well completion vessel means a vessel that contains *flowback* during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a tank or other vessel that is skid-mounted or portable. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart.

Well site means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, gas well, or injection well and its associated well pad.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58447, Sept. 23, 2013; 79 FR 79040, Dec. 31, 2014; 80 FR 48268, Aug. 12, 2015; 81 FR 35898, June 3, 2016; 85 FR 57069, Sept. 14, 2020; 89 FR 17036, Mar. 8, 2024]

Table 1 to Subpart OOOO of Part 60—Required Minimum Initial SO_2 Emission Reduction Efficiency (Z_i)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	$2.0 \le X \le 5.0$	$5.0 < X \le 15.0$	$15.0 < X \le 300.0$	$X > 300.0$
$Y \ge 50$	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller.		
$20 \le Y < 50$	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller		97.9
$10 \le Y < 20$	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 93.5, whichever is smaller	93.5	93.5
$Y < 10$	79.0	79.0	79.0	79.0

[78 FR 58447, Sept. 23, 2013]

Table 2 to Subpart OOOO of Part 60—Required Minimum SO_2 Emission Reduction Efficiency (Z_c)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	$2.0 \le X \le 5.0$	$5.0 < X \le 15.0$	$15.0 < X \le 300.0$	$X > 300.0$
$Y \ge 50$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller.		
$20 \le Y < 50$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 97.5, whichever is smaller		97.5
$10 \le Y < 20$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller	90.8	90.8
$Y < 10$	74.0	74.0	74.0	74.0

X = The sulfur feed rate from the sweetening unit (*i.e.*, the H_2S in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.

Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent H_2S (dry basis) rounded to one decimal place.

Z = The minimum required sulfur dioxide (SO_2) emission reduction efficiency, expressed as percent carried to one decimal place. Z_i refers to the reduction efficiency required at the initial performance test. Z_c refers to the reduction efficiency required on a continuous basis after compliance with Z_i has been demonstrated.

[78 FR 58447, Sept. 23, 2013]

Table 3 to Subpart OOOO of Part 60—Applicability of General Provisions to Subpart OOOO

As stated in § 60.5425, you must comply with the following applicable General Provisions:

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.1	General applicability of the General Provisions	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5430.

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.3	Units and abbreviations	Yes.	
§ 60.4	Address	Yes.	
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and record keeping	Yes	Except that § 60.7 only applies as specified in § 60.5420(a).
§ 60.8	Performance tests	Yes	Performance testing is required for control devices used on storage vessels and centrifugal compressors.
§ 60.9	Availability of information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart OOOO.
§ 60.12	Circumvention	Yes.	
§ 60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.
§ 60.14	Modification	Yes.	
§ 60.15	Reconstruction	Yes.	Except that § 60.15(d) does not apply to gas wells, pneumatic controllers, centrifugal compressors, reciprocating compressors or storage vessels.
§ 60.16	Priority list	Yes.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	Yes	Except that the period of visible emissions shall not exceed a total of 1 minute during any 15-minute period instead of 5 minutes during any 2 consecutive hours as required in § 60.18(c).
§ 60.19	General notification and reporting requirement	Yes.	

[77 FR 49542, Aug. 16, 2012, as amended at 81 FR 35898, June 3, 2016]

Title 40 —Protection of Environment
Chapter I —Environmental Protection Agency
Subchapter C —Air Programs
Part 60 —Standards of Performance for New Stationary Sources

Authority: 42 U.S.C. 7401 *et seq.*
Source: 36 FR 24877, Dec. 23, 1971, unless otherwise noted.

Subpart KKK—Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011

Source: 50 FR 26124, June 24, 1985, unless otherwise noted.

§ 60.630 Applicability and designation of affected facility.

(a)

(1) The provisions of this subpart apply to affected facilities in onshore natural gas processing plants.

(2) A compressor in VOC service or in wet gas service is an affected facility.

(3) The group of all equipment except compressors (defined in § 60.631) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after January 20, 1984, and on or before August 23, 2011, is subject to the requirements of this subpart.

(c) Addition or replacement of equipment (defined in § 60.631) for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d) Facilities covered by subpart VV or subpart GGG of 40 CFR part 60 are excluded from this subpart.

(e) A compressor station, dehydration unit, sweetening unit, underground storage tank, field gas gathering system, or liquefied natural gas unit is covered by this subpart if it is located at an onshore natural gas processing plant. If the unit is not located at the plant site, then it is exempt from the provisions of this subpart.

(f) An affected facility must continue to comply with the requirements of this subpart until it begins complying with a more stringent requirement, that applies to the same affected facility, in an approved, and effective, State or Federal plan that implements subpart OOOOc of this part, or modifies or reconstructs after December 6, 2022, and thus becomes subject to subpart OOOOb of this part.

[50 FR 26124, June 24, 1985, as amended at 77 FR 49542, Aug. 16, 2012; 89 FR 17034, Mar. 8, 2024]

§ 60.631 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VV of part 60; and the following terms shall have the specific meanings given them.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

Equipment means each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by this subpart.

Field gas means feedstock gas entering the natural gas processing plant.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485(e) or § 60.633(h)(2).

In wet gas service means that a piece of equipment contains or contacts the field gas before the extraction step in the process.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane, that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

§ 60.632 Standards.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of §§ 60.482-1 (a), (b), and (d) and 60.482-2 through 60.482-10, except as provided in § 60.633, as soon as practicable, but no later than 180 days after initial startup.

(b) An owner or operator may elect to comply with the requirements of §§ 60.483-1 and 60.483-2.

(c) An owner or operator may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of § 60.634 of this subpart.

(d) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of § 60.485 except as provided in § 60.633(f) of this subpart.

(e) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §§ 60.486 and 60.487 except as provided in §§ 60.633, 60.635, and 60.636 of this subpart.

(f) An owner or operator shall use the following provision instead of § 60.485(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-63, 77, or 93, E168-67, 77, or 92, or E260-73, 91, or 96 (incorporated by reference as specified in § 60.17) shall be used.

[50 FR 26124, June 24, 1985, as amended at 65 FR 61773, Oct. 17, 2000]

§ 60.633 Exceptions.

(a) Each owner or operator subject to the provisions of this subpart may comply with the following exceptions to the provisions of subpart VV.

(b)

(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in § 60.485(b) except as provided in §§ 60.632(c), paragraph (b)(4) of this section, and 60.482-4 (a) through (c) of subpart VV.

(2) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(3)

(i) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in § 60.482-9.

(ii) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(4)

(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by nonplant personnel may be monitored after a pressure release the next time the monitoring personnel are on site, instead of within 5 days as specified in paragraph (b)(1) of this section and § 60.482-4(b)(1) of subpart VV.

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section shall be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of § 60.482-5.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§ 60.482-2(a)(1) and 60.482-7(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§ 60.482-2(a)(1), 60.482-7(a), and paragraph (b)(1) of this section.

(f) Reciprocating compressors in wet gas service are exempt from the compressor control requirements of § 60.482-3.

(g) Flares used to comply with this subpart shall comply with the requirements of § 60.18.

(h) An owner or operator may use the following provisions instead of § 60.485(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86-78, 82, 90, 95, or 96 (incorporated by reference as specified in § 60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302 °F) as determined by ASTM Method D86-78, 82, 90, 95, or 96 (incorporated by reference as specified in § 60.17).

[50 FR 26124, June 24, 1985, as amended at 51 FR 2702, Jan. 21, 1986; 65 FR 61773, Oct. 17, 2000]

§ 60.634 Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the FEDERAL REGISTER a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

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

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) The Administrator will treat applications under this section according to the following criteria, except in cases where he concludes that other criteria are appropriate:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) If the applicant is an owner or operator of an affected facility, he must commit in writing to operate and maintain the alternative means so as to achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard.

§ 60.635 Recordkeeping requirements.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of § 60.486.

(b) The following recordkeeping requirements shall apply to pressure relief devices subject to the requirements of § 60.633(b)(1) of this subpart.

(1) When each leak is detected as specified in § 60.633(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in § 60.633(b)(2), the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) “Above 10,000 ppm” if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 10,000 ppm or greater.

(v) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of § 60.482-4(a). The designation of equipment subject to the provisions of § 60.482-4(a) shall be signed by the owner or operator.

(c) An owner or operator shall comply with the following requirement in addition to the requirement of § 60.486(j): Information and data used to demonstrate that a reciprocating compressor is in wet gas service to apply for the exemption in § 60.633(f) shall be recorded in a log that is kept in a readily accessible location.

§ 60.636 Reporting requirements.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of § 60.487.

(b) An owner or operator shall include the following information in the initial semiannual report in addition to the information required in § 60.487(b)

(1)-(4) : Number of pressure relief devices subject to the requirements of § 60.633(b) except for those pressure relief devices designated for no detectable emissions under the provisions of § 60.482-4(a) and those pressure relief devices complying with § 60.482-4(c).

(c) An owner or operator shall include the following information in all semiannual reports in addition to the information required in § 60.487(c)(2) (i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in § 60.633(b)(2) and

(2) Number of pressure relief devices for which leaks were not repaired as required in § 60.633(b)(3).

Title 40 —Protection of Environment
Chapter I —Environmental Protection Agency
Subchapter C —Air Programs
Part 60 —Standards of Performance for New Stationary Sources

Source: 84 FR 32579, July 8, 2019, unless otherwise noted.
Source: 80 FR 64648, Oct. 23, 2015, unless otherwise noted.
Source: 80 FR 13715, Mar. 16, 2015, unless otherwise noted.
Source: 89 FR 17140, Mar. 8, 2024, unless otherwise noted.
Source: 89 FR 17043, Mar. 8, 2024, unless otherwise noted.
Source: 81 FR 35898, June 3, 2016, unless otherwise noted.
Source: 77 FR 49542, Aug. 16, 2012, unless otherwise noted.
Source: 76 FR 15404, Mar. 21, 2011, unless otherwise noted.
Source: 76 FR 15404, Mar. 21, 2011, unless otherwise noted.
Source: 71 FR 38497, July 6, 2006, unless otherwise noted.
Source: 73 FR 3591, Jan. 18, 2008, unless otherwise noted.
Source: 71 FR 39172, July 11, 2006, unless otherwise noted.
Source: 70 FR 74907, Dec. 16, 2005, unless otherwise noted.
Source: 70 FR 74892, Dec. 16, 2005, unless otherwise noted.
Source: 84 FR 15884, Apr. 16, 2019, unless otherwise noted.
Source: 84 FR 15853, Apr. 16, 2019, unless otherwise noted.
Source: 65 FR 76384, Dec. 6, 2000, unless otherwise noted.
Source: 65 FR 76355, Dec. 6, 2000, unless otherwise noted.
Source: 81 FR 59368, Aug. 29, 2016, unless otherwise noted.
Source: 61 FR 9919, Mar. 12, 1996, unless otherwise noted.
Source: 54 FR 37551, Sept. 11, 1989, unless otherwise noted.
Source: 57 FR 44503, Sept. 28, 1992, unless otherwise noted.
Source: 88 FR 18067, Mar. 27, 2023, unless otherwise noted.
Source: 53 FR 2676, Jan. 29, 1988, unless otherwise noted.
Source: 53 FR 38914, Oct. 3, 1988, unless otherwise noted.
Source: 58 FR 45962, Aug. 31, 1993, unless otherwise noted.
Source: 53 FR 47623, Nov. 23, 1988, unless otherwise noted.
Source: 50 FR 7699, Feb. 25, 1985, unless otherwise noted.
Source: 74 FR 19309, Apr. 28, 2009, unless otherwise noted.
Source: 55 FR 26942, June 29, 1990, unless otherwise noted.
Source: 50 FR 40160, Oct. 1, 1985, unless otherwise noted.
Source: 50 FR 26124, June 24, 1985, unless otherwise noted.
Source: 49 FR 37331, Sept. 21, 1984, unless otherwise noted.
Source: 55 FR 26922, June 29, 1990, unless otherwise noted.
Source: 49 FR 13651, Apr. 5, 1984, unless otherwise noted.
Source: 72 FR 64896, Nov. 16, 2007, unless otherwise noted.
Source: 49 FR 22606, May 30, 1984, unless otherwise noted.
Source: 49 FR 26892, June 29, 1984, unless otherwise noted.
Source: 55 FR 51035, Dec. 11, 1990, unless otherwise noted.
Source: 52 FR 34874, Sept. 15, 1987, unless otherwise noted.
Source: 80 FR 13702, Mar. 16, 2015, unless otherwise noted.
Source: 48 FR 37590, Aug. 18, 1983, unless otherwise noted.
Source: 48 FR 38737, Aug. 25, 1983, unless otherwise noted.
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Source: 48 FR 48335, Oct. 18, 1983, unless otherwise noted.
Source: 47 FR 34143, Aug. 6, 1982, unless otherwise noted.
Source: 47 FR 49612, Nov. 1, 1982, unless otherwise noted.

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Source: 47 FR 49287, Oct. 29, 1982, unless otherwise noted.
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Source: 62 FR 48382, Sept. 15, 1997, unless otherwise noted.
Source: 60 FR 65419, Dec. 19, 1995, unless otherwise noted.
Source: 56 FR 5507, Feb. 11, 1991, unless otherwise noted.
Source: 72 FR 32759, June 13, 2007, unless otherwise noted.
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Source: 60 FR 65414, Dec. 19, 1995, unless otherwise noted.
Source: 61 FR 9919, Mar. 12, 1996, unless otherwise noted.
Source: 60 FR 65415, Dec. 19, 1995, unless otherwise noted.
Source: 84 FR 32575, July 8, 2019, unless otherwise noted.
Source: 40 FR 53346, Nov. 17, 1975, unless otherwise noted.
Authority: 42 U.S.C. 7401 *et seq.*
Source: 36 FR 24877, Dec. 23, 1971, unless otherwise noted.

Appendix K to Part 60—Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging

1.0 Scope and Application

1.1 *Analytes.*

Analytes	CAS No.
Volatile Organic Compounds (VOCs)	No CAS number assigned.

Analytes	CAS No.
Methane	74-82-8.
Ethane	74-84-0.

1.1.1 This protocol is applicable to the detection of VOCs, including hazardous air pollutants, and hydrocarbons, such as methane and ethane.

1.2 ***Scope.*** This protocol covers surveys of process equipment using Optical Gas Imaging (OGI) cameras in sectors where the majority of constituents (>75 percent by volume) in the emissions streams have a response factor of at least 0.25 when compared to the response factor of propane and can be imaged by the equipment specified in Section 6.0. The specific component focus for the surveys is determined by the referencing subpart, and can include, but is not limited to, valves, flanges, connectors, pumps, compressors, open-ended lines, pressure relief devices, and seal systems.

1.3 ***Applicability.*** This protocol is applicable to facilities when specified in a referencing subpart. This protocol is intended to help determine the presence and location of leaks and is not currently applicable for use in direct emission rate measurements from sources.

2.0 Summary

2.1 A field portable infrared (IR) camera capable of imaging the target gas species is employed to survey process equipment and locate fugitive or leaking gas emissions. By restricting the amount of incoming thermal radiation to a small bandwidth corresponding to a region of interaction for the gas species of interest, the camera provides an image of an invisible gas to the camera operator. The camera type and manufacturer are not specified in this protocol, but the camera used must meet the specifications and performance criteria presented in Section 6. The keys to becoming proficient and maintaining leak detection proficiency using OGI cameras are proper camera operator training with sufficient field experience and conducting OGI surveys frequently throughout the year.

3.0 Definitions

Ambient air temperature means the air temperature in the general location of the component being surveyed.

Camera configuration means different ways of setting up an OGI camera that affect its detection capability. Examples of camera configurations that can be changed include the operating mode (*e.g.,* standard versus high sensitivity or enhanced), the lens, the portability (*e.g.,* handheld versus tripod), and the viewer (*e.g.,* OGI camera screen versus an external device like a tablet).

Delta temperature (delta-T or ΔT) means the difference in temperature between the emitted process gas temperature and the surrounding background temperature. It is an acceptable practice in the field to assume that the emitted process gas temperature is equal to the ambient air temperature.

Dwell time means the minimum amount of time required to survey a scene in order to provide adequate probability of leak detection. The dwell time is the active time the operator is looking for potential leaks and does not begin until the scene is in focus and steady.

Fugitive emission or leak means any emissions observed using OGI from components regulated by the referencing subpart.

Imaging is the process of producing a visual representation of emissions that may otherwise be invisible to the naked eye.

Monitoring survey means imaging equipment with an OGI camera at one site on one day. Changing the site being surveyed or changing the day of imaging constitutes a new monitoring survey.

OGI camera operator is someone who has completed the training required in Section 10 and passed the final survey test in Section 10.2.2.4.

Operating envelope means the range of conditions (*i.e.,* wind speed, delta-T, viewing distance) within which a survey must be conducted to achieve the quality objective.

Optical gas imaging camera means any field portable instrumentation that makes visible emissions that may otherwise be invisible to the naked eye.

Persistent leak is any leak that is not intermittent in nature.

Referencing subpart means a subpart in this part or in 40 CFR part 61, 62, 63, or 65 that requires the monitoring of regulated equipment for fugitive emissions or leaks, for which this protocol is referenced.

Response factor means the OGI camera's response to a compound of interest relative to a reference compound at a concentration path-length of 10,000 parts per million-meter. Response factors are specific to the OGI camera model and can be obtained from peer reviewed articles or may be developed according to procedures specified in Annex 1 of this appendix K.

Senior OGI camera operator is a camera operator who has conducted OGI surveys for a minimum of 1400 survey hours over the entirety of his/her career, including at least 40 survey hours in the past 12 months, and has completed or developed the classroom camera operator training as defined in Section 10.2.1. Previous 12 months means the 365-calendar days prior to the day of the activity that requires a senior OGI camera operator. The survey hours spent by the senior OGI camera operator performing comparative monitoring, either as part of initial training, retraining, or auditing other OGI camera operators, can be included when determining the senior OGI camera operator's experience both over his/her career and the past 12 months.

Simple scene is defined as a scene that contains 10 or fewer components in the field of view.

Survey hour is 60 minutes of observation conducted with an OGI camera. Survey hours do not include periods of time when the OGI camera operator is on a rest break. The 60 minutes do not need to be consecutive but are cumulative.

4.0 Interferences

4.1 Interferences from atmospheric conditions can impact the operator's ability to detect gas leaks. It is recommended that conditions involving steam, fog, mist, rain, solar glint, high particulate matter concentrations, and extremely hot backgrounds are avoided for a survey of acceptable quality.

5.0 Safety

5.1 Site Hazards. Prior to applying this protocol in the field, the potential hazards at the survey site should be considered; advance coordination with the site is critical to understand the conditions and applicable safety policies. Users should be aware of safety concerns with viewing equipment through a camera while walking around an industrial setting. Users should also be aware of hazards related to eye strain, eye fatigue, and mental fatigue that may occur from prolonged periods of viewing equipment with an OGI camera. This protocol does not address all of the safety concerns associated with its use. It is the responsibility of the user of this protocol to establish appropriate health and safety practices and determine the applicability of regulatory limitations prior to implementing this protocol.

5.2 Hazardous Pollutants. Several of the compounds encountered over the course of implementing this protocol may be irritating or corrosive to tissues (*e.g.,* heptane) or may be toxic (*e.g.,* benzene, methyl alcohol, hydrogen sulfide). Nearly all are fire hazards. Chemical compounds in gaseous emissions should be determined from process knowledge of the source. Appropriate precautions can be found in reference documents, such as reference 13.1.

6.0 Equipment and Supplies

6.1 An OGI camera model meeting the following specifications is required. This testing can be performed by the owner or operator, the camera manufacturer, or a third party. As required by Section 8.1, this testing must be performed initially, prior to using the OGI camera to conduct surveys. The determination in Section 6.1.1 must also be made any time the OGI camera will be used to survey components on equipment that was not previously included in monitoring surveys or whenever there are process changes that are expected to cause the gaseous emissions composition to change. The determination in Section 6.1.2 is only required initially and is required for each camera operating mode (*e.g.,* standard versus high sensitivity or enhanced).

6.1.1 The spectral range of infrared radiation measured by the OGI camera must overlap with a major absorption peak for the chemical target of interest, meaning the OGI camera must be sensitive with a response factor of at least 0.25 when compared to the response factor of propane for the majority of constituents (>75 percent by volume) of the expected gaseous emissions composition.

6.1.2 The OGI camera must be capable of detecting (or producing a detectable image of) methane emissions of 19 grams per hour (g/hr) and either n-butane emissions of 29 g/hr or propane emissions of 22 g/hr at a viewing distance of 2.0 meters and a delta-T of 5.0 °C in an environment of calm wind conditions around 1 meter per second (m/s) or less, unless the referencing subpart provides detection rates for a different compound(s) for that subpart.

6.2 The following items are needed for the initial specification confirmation of each OGI camera model, as required by Sections 6.1.2, and development of operating envelopes, as required by Section 8:

6.2.1 Methane test gas, chemically pure grade (99.5 percent) or higher.

6.2.2 n-Butane test gas or propane test gas, chemically pure grade (99 percent) or higher.

6.2.3 Release orifice, 1⁄4 inch (64 millimeter) inner diameter.

6.2.4 Mass flow controller or rotameter, capable of controlling the gas emission rate within an accuracy of 5 percent and traceable to the International System of Units (SI) through an unbroken chain of comparisons, *i.e.,* calibrations.

6.2.5 An industrial fan, capable of adjusting the sustained nominal wind speeds at regular intervals, with the ability to maintain a spatially uniform set speed within 20 percent of the target wind speed over the area of detection.

6.2.6 A meteorological station capable of providing representative data on ambient temperature, ambient pressure, relative humidity, and wind speed and direction at least once every hour. Follow the calibration and standardization requirements for meteorological measurements in EPA-454/B-08-002 (incorporated by reference, see § 60.17). The equipment must meet the following minimum specifications:

6.2.6.1 Ambient temperature readings accurate to at least 0.50 °C, with a resolution of 0.10 °C or less, and a minimum range of −20 to 70 °C.

6.2.6.2 Ambient pressure readings accurate to at least 5.0 millibar (mbar), with a resolution of 1.0 mbar or less, and a minimum range of 700 to 1100 mbar.

6.2.6.3 Wind speed readings accurate to at least 1.0 m/s, with a resolution of 0.10 m/s or less, and a minimum range of 0.10 to 20 m/s.

6.2.6.4 Wind direction readings accurate to at least 5 degrees, with a resolution of 1 degree or less.

6.2.6.5 Relative humidity readings accurate to at least 5.0 percent, with a resolution of 0.50 percent or less, and a minimum range of 10 to 90 percent noncondensing.

6.2.7 A temperature-controlled background large enough for viewing the emissions plume and capable of maintaining a uniform temperature. Uniform is defined as all points on the background deviating no more than 1.0 °C from the average temperature of the background.

6.2.8 T-type probe thermocouple and readout, accurate to at 1.0 °C and traceable to the SI through an unbroken chain of comparisons, *i.e.,* calibrations, for measuring the test gas at or near the point of release.

6.2.9 T-type surface skin thermocouple and readout, accurate to at 1.0 °C and traceable to the SI through an unbroken chain of comparisons, *i.e.,* calibrations, for measuring the background immediately behind the test gas.

6.2.10 Device to measure the distance between the OGI camera and the release point (*e.g.,* tape measure, laser measurement tool), accurate to at least 2.0 centimeters (cm), with a resolution of at least 1.0 cm and traceable to the SI through an unbroken chain of comparisons, *i.e.,* calibrations.

7.0 Camera Calibration and Maintenance

7.1 The camera does not require routine calibration for purposes of gas leak detection but may require calibration if it is used for thermography (such as with ΔT determination features). Operators should follow manufacturer recommendations regarding maintenance and calibration, as appropriate.

8.0 Camera Specification Confirmation and Development of the Operating Envelope

8.1 Determine that the OGI camera meets the specifications in Section 6.1 prior to conducting surveys with the OGI camera. The determination in Section 6.1.1 must also be made any time the OGI camera will be used to survey components on equipment that was not previously included in monitoring surveys or whenever there are process changes that are expected to cause the gaseous emissions composition to change. The determination in Section 6.1.2 is only required initially. The results of this determination must be documented.

8.2 Field conditions such as the viewing distance to the component to be monitored, wind speed, ambient air temperature, and the background temperature all have the potential to impact the ability of the OGI camera operator to detect a leak. It is important that the OGI camera has been tested under the full range of expected field conditions in which the OGI camera will be used.

8.3 An operating envelope must be established for field use of the OGI camera. Imaging must not be performed when the conditions are outside of the developed operating envelope.

8.3.1 The operating envelope is specific to each model of OGI camera. The operating envelope can be developed by the owner or operator, the camera manufacturer, or a third party. The operating envelope must be developed initially, prior to conducting surveys with the OGI camera. The operating envelope may be updated or expanded at any time, following the procedures in this section.

8.3.2 The operating envelope must be confirmed for all potential configurations that could impact the detection limit, such as high sensitivity modes, available lenses, and handheld versus tripod. Conversely, separate operating envelopes may be developed for different configurations. If, in addition to or in lieu of the display on the camera itself, an external device (*e.g.,* laptop, tablet) is intended to be used to visualize the leak in the field, the operating envelope must be developed while using the external device. If the external device will not be used at all times, use of the external device is considered a separate configuration, and the operating envelope testing must be performed for both configurations.

8.4 Development of the operating envelope is to be performed using the test gas composition, flow rate, and orifice diameter described in Section 6.1.2, and must include the following variables:

8.4.1 Delta-T, regulated through the use of a temperature-controlled background encompassing approximately 50 percent of the field of view, with no potential for solar interference;

8.4.2 Viewing distance from the OGI camera to the component being imaged; and

8.4.3 Wind speed, controlled through the use of an industrial fan.

8.5 Determine the operating envelope using the following procedure:

8.5.1 Set up the methane test gas at a flow rate of 19 g/hr.

8.5.2 For this flow rate, the ability of the OGI camera to produce an observable image is challenged by ranges of the variables in Sections 8.4.1 through 8.4.3.

8.5.3 A panel of no less than 4 observers who have been trained using the OGI camera and who have a demonstrated capability of detecting gaseous leaks will observe the test gas release for each combination of delta-T, distance, and wind speed. A test emission is determined to be observed when at least 75 percent of the observers (*i.e.,* 3 of the 4 observers) see the image.

8.5.4 Repeat the procedures in Sections 8.5.2 and 8.5.3 using either an n-butane test gas at a flow rate of 29 g/hr or a propane test gas at a flow rate of 22 g/hr.

8.5.5 The operating envelope to be used in the field for each OGI camera configuration tested is the more restrictive operating envelope developed between the two test gases.

8.5.6 Repeat the procedures in Sections 8.5.1-8.5.5 for each camera configuration that will be used to conduct surveys in the field.

8.6 The results of the testing to establish the operating envelope, including supporting videos, must be documented.

8.7 If an operating envelope has not been developed for an OGI camera model or an OGI camera operator wants to expand an operating envelope to account for site-specific conditions, a daily field check for maximum viewing distance must be completed prior to conducting a monitoring survey. This daily field check for maximum viewing distance does not need to be performed if an OGI suvey will be conducted within an operating envelope developed according to Sections 8.3 through 8.6.

8.7.1 A complete video record of the daily field check must be retained with the OGI survey records.

8.7.2 Each OGI camera operator who will conduct the monitoring survey must complete their own daily field check for maximum viewing distance using the OGI camera they will use to complete the monitoring survey. The daily field check must be conducted for each camera configuration that will be used during the monitoring survey.

8.7.3 The daily field check must be performed using the test gas composition and orifice diameter described in Section 6.1.2.

8.7.4 The daily field check must be conducted first for methane at a flow rate of 19 g/hr and then for either n-butane at a flow rate of 29 g/hr or propane at a flow rate of 22 g/hr. You must use a flow meter with a minimum accuracy of 5 percent of the mass rate. The daily field check for the two gases must occur at the same delta-T and wind speed conditions.

8.7.5 The OGI camera operator must determine the maximum distance from the gas release point at which the operator is able to visualize the gas release with the OGI camera. The OGI camera operator must document this distance, as well as the delta-T and the wind speed at the time of the daily field check and include this information with the OGI survey records.

8.7.6 If the daily check results in different maximum viewing distances for methane and n-butane/propane, the maximum viewing distance for the day for the OGI camera operator will be the shorter of the two maximum viewing distances.

8.7.7 If the delta-T in the field decreases below the delta-T that was recorded for the daily field check or if the wind speed increases above the wind speed recorded for the daily field check, the maximum viewing distance determination must be repeated for the new delta-T and wind speed conditions.

8.7.8 If multiple camera configurations will be used during the monitoring survey, the OGI camera operator may use the shortest maximum viewing distance of any configuration for all the configurations that will be used during the survey, or the OGI camera operator may use a different maximum viewing distance for each configuration that will be used during the survey.

9.0 Conducting the Monitoring Survey

Each site must have a monitoring plan that describes the procedures for conducting a monitoring survey. One monitoring plan can be used for multiple sites, as long as the plan contains the relevant information for each site. At a minimum, the monitoring plan must include the elements in this section.

9.1 The monitoring plan must include a description of a daily verification check to be performed prior to imaging to confirm that the camera is operating properly. This verification must consist of the following at a minimum:

9.1.1 Confirm that the OGI camera software loads successfully and does not display any error messages upon startup;

9.1.2 Confirm that the OGI camera focuses properly at the shortest and longest distances that will be imaged;

9.1.3 Confirm that the OGI camera produces a live IR image using a known emissions source, such as a butane lighter or a propane cylinder;

9.1.4 Confirm that the OGI camera can perform the delta-T check function as expected if this function will be used to meet the requirement in Section 9.2.3.

9.2 The monitoring plan must include a procedure for ensuring that the monitoring survey is performed only when conditions in the field are within the operating envelope established in Section 8 or the conditions established by the daily field check in Section 8.7. This procedure must include the following:

9.2.1 If the OGI camera operator will use an operating envelope established under Section 8, a description of how the viewing distance from the surveyed components, the wind speed, and the delta-T will be monitored and how the operator will deal with changes in site conditions during the survey to ensure that the monitoring survey is conducted within the limits of the operating envelope;

9.2.2 If the OGI camera operator performs a daily field check according to Section 8.7, a description of how the OGI camera operator will monitor viewing distance to ensure the viewing distance is less than the daily maximum viewing distance and how the OGI camera operator will monitor the delta-T and wind speed to ensure the delta-T remains above and the wind speed remains below those that occurred during the daily field check;

9.2.3 Description of how the operator will ensure an adequate delta-T is present in order to view potential gaseous emissions, *e.g.,* using a delta-T check function built into the features of the OGI camera or using a background temperature reading in the OGI camera field of view;

9.2.4 Description of how the operator will recognize the presence of and deal with potential interferences and/or adverse monitoring conditions, such as steam, fog, mist, rain, solar glint, extremely high concentrations of particulate matter, and hot temperature backgrounds.

9.3 The site must conduct monitoring surveys using a methodology that ensures that all the components regulated by the referencing subpart within the unit or area are monitored. This must be achieved using one of the following three approaches or a combination of these approaches. The approach(es) chosen and how the approach(es) will be implemented must be described in the monitoring plan.

9.3.1 Use of a route map or a map with designated observation locations. The map must be included as part of the monitoring plan, with a predetermined sequence of process unit monitoring (such as directional arrows along the monitoring path) depicted or designated observation locations clearly marked.

9.3.2 Use of visual cues. The facility must develop visual cues (*e.g.,* tags, streamers, or color-coded pipes) to ensure that all components regulated by the referencing subpart were monitored. The monitoring plan must describe what visual cue method is used and how it will be used to ensure all components are monitored during the survey.

9.3.3 Use of global positioning system (GPS) route tracing. The facility must document the path taken during the survey by capturing GPS coordinates along the survey path, along with date and time stamps. These locations should be identified by latitude and longitude coordinates in decimal degrees to an accuracy and precision of at least five decimals of a degree using the North American Datum of 1983. GPS coordinates must be recorded frequently enough to document that all components regulated by the referencing subpart were monitored. The monitoring plan must describe how often GPS coordinates will be recorded and how the route tracing will ensure all components regulated by the referencing subpart are monitored.

9.4 The monitoring plan must include a procedure that describes how components will be viewed with the OGI camera.

9.4.1 Components must be imaged from at least two different angles.

9.4.2 For a simple scene, which is a scene that contains 10 or fewer components in the field of view, the OGI camera operator must have a minimum dwell time on each angle of 10 seconds per scene before changing the angle, distance, or focus and dwelling again.

9.4.3 For scenes other than simple scenes, the operator must divide the scene into manageable subsections. The OGI camera operator must have a minimum dwell time of 2 seconds per component in the field of view for each angle.

9.4.4 It may be necessary to reduce distance or change angles in order to reduce the number of components in the field of view. An OGI camera operator may choose to reduce the distance from components in order to create simple scenes.

9.4.5 The required dwell times stated in this section are minimum dwell times. Additional dwell time may be necessary to assess whether each monitored component is leaking or not leaking. OGI camera operators should use training and knowledge of environmental conditions and component configurations to increase dwell time where appropriate.

9.4.6 The dwell time is the time that the OGI camera is in a particular operating mode and the scene is in focus and held steady such that an OGI camera operator is able to monitor for leaks. Changing OGI camera operating modes or viewing angles requires the OGI camera operator to restart the dwell time.

9.4.7 The procedure must discuss changes, if necessary, to the imaging mode of the OGI camera that are appropriate to ensure that leaks from all components regulated by the referencing subpart can be imaged.

9.5 The monitoring plan must include a plan for avoiding camera operator fatigue, as physical, mental, and eye fatigue are concerns with continuous field operation of OGI cameras. The OGI camera operator should not survey continuously for a period of more than 30 minutes without taking a rest break. Taking a rest break between surveys of process units may satisfy this requirement; however, for process units or complex scenes requiring continuous survey periods of more than 30 minutes, the operator must take a break of at least 5 minutes after every 30 minutes of surveying. Operators can complete tasks related to the monitoring survey, such as documentation, during the 5-minute rest break, so long as the operator is not actively imaging components.

NOTE: If continuous surveying is desired for extended time periods, two camera operators can alternate between surveying and taking breaks.

9.6 The monitoring plan must include a procedure for documenting monitoring surveys. The information documented must include:

9.6.1 The name of the facility, date, and approximate start and end times for each monitoring survey.

9.6.2 The weather conditions, including ambient temperature, wind speed, relative humidity, and sky conditions at the start and end of each monitoring survey. For monitoring surveys conducted for more than four hours, record the weather conditions every two hours.

9.7 The site must have a procedure for documenting fugitive emissions or leaks found during the monitoring survey.

9.7.1 If a leak is found, capture either a short video clip or photograph of the component associated with the leak. If the leak is not immediately repaired, the leaking component must be tagged for repair. The date, time, location of the leak, and an identification of the component associated with the leak must be recorded and stored with the OGI survey records. A full recording of the survey will suffice for this requirement.

9.7.2 If no emissions are found, no recorded footage is required to demonstrate that the component was not leaking.

9.8 The monitoring plan must include a quality assurance (QA) verification video for each OGI operator at least once each monitoring day. The QA verification video must be a minimum of 5 minutes long and document the procedures the operator uses to survey (*e.g.,* dwell times, angles, distances, backgrounds) and the camera configuration.

9.9 The monitoring plan must describe the process that will be used to ensure the validity of the monitoring data as detailed in Section 11.

10.0 Camera Operator Training

10.1 The facility or company performing the OGI surveys must have a training plan which ensures and monitors the proficiency of the camera operators. Training should include classroom instruction and field training on the OGI camera and external devices, monitoring techniques, best practices, process knowledge, and other regulatory requirements related to leak detection that are relevant to the facility's OGI monitoring efforts. If the facility does not perform its own OGI monitoring, the facility must ensure that the training plan for the company performing the OGI surveys adheres to this requirement.

10.2 Prior to conducting monitoring surveys, camera operators must complete initial training and demonstrate proficiency with the OGI camera and any external devices to be utilized for detecting a potential leak.

10.2.1 At a minimum, the training plan must include the following classroom training elements as part of the initial training. Classroom training can be conducted at a physical location, remotely, or online.

10.2.1.1 Key fundamental concepts of the OGI camera technology, such as the types of images the camera is capable of visualizing and the technology basis (theory) behind this capability.

10.2.1.2 Parameters that can affect image detection (*e.g.,* wind speed, temperature, distance, background, and potential interferences).

10.2.1.3 Description of the components to be surveyed and example imagery of the various types of leaks that can be expected.

10.2.1.4 Operating and maintenance instructions for the OGI camera used at the facility.

10.2.1.5 Procedures for performing the monitoring survey according to the monitoring plan, including the daily verification check; how to ensure the monitoring survey is performed only when the conditions in the field are within the established operating envelope; the number of angles a component or set of components should be imaged from; the minimum dwell time for a scene before changing the angle, distance, and/or focus; how to improve the background visualization; the procedure for ensuring that all components regulated by the referencing subpart are visualized; and required rest breaks.

10.2.1.6 Recordkeeping requirements.

10.2.1.7 Common mistakes and best practices.

10.2.1.8 Discussion of the regulatory requirements related to leak detection that are relevant to the facility's OGI monitoring efforts.

10.2.2 At a minimum, the training plan must include the following field training elements as part of the initial training:

10.2.2.1 A minimum of 3 survey hours with OGI where trainees observe the techniques and methods of a senior OGI camera operator (see definition in Section 3.0) who reinforces the classroom training elements.

10.2.2.2 A minimum of 12 survey hours with OGI where the trainee performs the initial OGI survey with a senior OGI camera operator verifying the results by conducting a side-by-side comparative survey and providing instruction/correction where necessary.

10.2.2.3 A minimum of 15 survey hours with OGI where the trainee performs monitoring surveys independently with a senior OGI camera operator trainer present and the senior OGI camera operator providing oversight and instruction/correction to the trainee where necessary.

10.2.2.4 A final monitoring survey test where the trainee conducts an OGI survey of at least 2 suvey hours and a senior OGI camera operator follows behind with a second camera to confirm the OGI survey results. If there are 10 or more leaks identified by the senior OGI operator, the trainee must achieve no more than 10 percent missed persistent leaks relative to the senior OGI camera operator to be considered authorized for independent survey execution. If there are less than 10 leaks identified by the senior OGI operator, the trainee must achieve zero missed persistent leaks relative to the senior OGI camera operator to be considered authorized for independent survey execution.

10.2.2.5 If the trainee doesn't pass the monitoring survey test in Section 10.2.2.4, the senior OGI operator must discuss the reasons for the failure with the trainee and provide instruction/correction on improving the trainee's performance. Following the discussion with the senior OGI operator, the trainee may repeat the test in Section 10.2.2.4.

10.3 All OGI camera operators must attend a biennial classroom training refresher. This refresher can be shorter in duration than the initial classroom training but must cover all the salient points necessary to operate the camera (*e.g.,* performing surveys according to the monitoring plan, best practices, discussion of lessons learned). Refresher training can be conducted at a physical location, remotely, or online.

10.4 Performance audits for all OGI camera operators must occur on a semiannual basis with at least three months between two consecutive audits. Performance audits must be conducted according to one of the following procedures:

10.4.1 Performance audit by comparative monitoring. Comparative monitoring in near real-time is where a senior OGI camera operator reviews the performance of the employee being audited by performing an independent monitoring survey.

10.4.1.1 Following a survey conducted by the camera operator being audited, the senior OGI camera operator will conduct a survey of at least 2 survey hours in the same area to ensure that no persistent leaks were missed.

10.4.1.2 If there are 10 or more leaks identified by the senior OGI operator, the camera operator being audited must achieve no more than 10 percent missed persistent leaks relative to the senior OGI camera operator. If there are less than 10 leaks identified by the senior OGI operator, the camera operator being audited must achieve zero missed persistent leaks relative to the senior OGI camera operator. If the camera operator being audited does not achieve this benchmark, then the camera operator being audited will need to be retrained as outlined in Section 10.4.3.

10.4.2 Performance audit by video review. The camera operator being audited must submit unedited and uncut video footage of their OGI survey technique to a senior OGI camera operator for review.

10.4.2.1 The videos must contain at least 2 survey hours of survey footage. If a single monitoring survey is less than 2 survey hours, footage from multiple monitoring surveys may be submitted; however, all videos necessary to cover a 2-hour period must be recorded and submitted for review. The senior OGI camera operator will review the survey technique of the camera operator being audited, as well as look for any missed leaks.

10.4.2.2 If the senior OGI camera operator finds that the survey techniques during the video review do not match those described in the monitoring plan, then the camera operator being audited will need to be retrained as outlined in Section 10.4.3. Additionally, if there are 10 or more leaks identified by the senior OGI operator, the camera operator being audited must achieve no more than 10 percent missed persistent leaks relative to the senior OGI camera operator. If there are less than 10 leaks identified by the senior OGI operator, the camera operator being audited must achieve zero missed persistent leaks relative to the senior OGI camera operator. If the camera operator being audited does not achieve this benchmark, then the camera operator being audited will need to be retrained as outlined in Section 10.4.3.

10.4.3 At a minimum, retraining must consist of the following elements:

10.4.3.1 A discussion of the reasons for the failure with the OGI operator being audited and techniques to improve performance.

10.4.3.2 A minimum of 8 survey hours with OGI where the trainee performs the initial OGI survey with a senior OGI camera operator verifying the results by conducting a side-by-side comparative survey and providing instruction/correction where necessary.

10.4.3.3 A minimum of 8 survey hours with OGI where the trainee performs the survey independently with the senior OGI camera operator trainer present and the senior OGI camera operator provides oversight and instruction/correction to the trainee where necessary.

10.4.3.4 The audited camera operator must perform a final monitoring survey test as described in Section 10.2.2.4 and meet the requirements in Section 10.2.2.4 to be recertified.

10.4.4 If an OGI operator requires retraining in two consecutive semiannual audits, the OGI operator must repeat the initial training requirements in Section 10.2.

10.4.5 If a camera operator is not scheduled to perform an OGI survey during a semiannual period, then the audit must occur with the next scheduled monitoring survey.

10.5 If an OGI camera operator has not conducted a monitoring survey in over 12 months, then the operator must complete the retraining requirements in Section 10.4.3 prior to conducting surveys. If an OGI camera operator has not conducted a monitoring survey in over 24 months, then the operator must complete the biennial classroom training in Section 10.3 and complete the retraining requirements in Section 10.4.3 prior to conducting surveys.

10.6 Previous experience with OGI camera operation can be substituted for some of the initial training requirements in Section 10.2 as outlined in this Section 10.6.1 and 10.6.2.

10.6.1 OGI camera operators with previous classroom training (at a physical location, remotely, or online) that included a majority of the elements listed in Section 10.2.1 do not need to complete the initial classroom training as described in Section 10.2.1, but if the date of training is more than two years before March 8, 2024, the biennial classroom training in Section 10.3 must be completed in lieu of the initial classroom training in Section 10.2.1.

10.6.2 OGI camera operators who have 40 survey hours of experience over the 12 calendar months prior to March 8, 2024 may substitute the retraining requirements in Section 10.4.3, including the final monitoring survey test, for the initial field training requirements in Section 10.2.2.

11.0 Quality Assurance and Quality Control

11.1 As part of the facility's monitoring plan, the facility must have a process which ensures the validity of the monitoring data. Examples may include routine review and sign-off of the monitoring data by the camera operator's supervisor, periodic comparative monitoring using a different camera operator as part of a continuing training verification plan described in Section 10, or other due diligence procedures.

11.2 For each monitoring day, the daily OGI camera verification must be performed as described in Section 9.1. Additionally, the daily QA verification video for each operator must be recorded as described in Section 9.8 for each operator for each monitoring day.

11.3 The following table is a summary of the mandatory QA and quality control (QC) measures in this protocol with the associated frequency and acceptance criteria. All of the QA/QC data must be documented and kept with other OGI records.

Summary Table of QA/QC

Parameter	QA/QC specification	Acceptance criteria	Frequency
OGI Camera Design	Spectral bandpass range	Must overlap with major absorption peak of the compound(s) of interest	Once initially (prior to using the OGI camera to conduct surveys), when survey components on equipment that was not previously included in monitoring surveys, whenever there are process changes that are expected to cause the gaseous emissions composition to change.
OGI Camera Design	Initial camera specification confirmation	Must be capable of detecting (or producing a detectable image of) methane emissions of 19 g/hr and either n-butane emission of 29 g/hr or propane emissions of 22 g/hr at a viewing distance of 2.0 meters and a delta-T of 5.0 °C in an environment of calm wind conditions around 1.0 m/s or less	Once initially (prior to using the OGI camera to conduct surveys).
Developing the Operating Envelope	Observation confirmation	Leak is observed by 3 out of 4 panel observers for specific combinations of delta-T, distance, and wind speed	Once initially (prior to using the OGI camera to conduct surveys) and prior to using a new camera configuration for which an envelope was not previously established. The operating envelope may be updated or expanded at any time, following the procedures in Section 8.
Daily Field Check	Maximum viewing distance	Determine distance at which each OGI camera operator can visualize leaks according to Section 8.7	Each monitoring day. Not required for OGI camera operators using operating envelopes established according to Section 8.

Parameter	QA/QC specification	Acceptance criteria	Frequency
OGI Camera Functionality	Verification Check	Meet the requirements of Section 9.1 to confirm that the OGI camera software loads successfully and that the camera focuses properly, produces a live IR image, and, as applicable, performs the delta-T check function	Each monitoring day, prior to conducting a survey.
Camera Operator Training	Classroom training	Meet the requirements of Sections 10.2.1 and 10.3 with the issuing of a certificate or record of attendance	Prior to conducting surveys (except as noted in Section 10.6.1), with a biennial refresher.
Camera Operator Training	Field training	Meet the requirements of Section 10.2.2 while maintaining the records of survey hours by the trainee along with a certificate or record of completion issued upon passing the final monitoring survey test in Section 10.2.2.4 with the date of the survey recorded	Except as noted in Section 10.6.2, prior to conducting surveys and if retraining is required following two consecutive semiannual audits.
OGI Camera Operator Performance	Semiannual performance audits	Comparative monitoring or video review. Meet the benchmarks in Section 10.4.1.2 or 10.4.2.2	Every 6 months, with at least 3 months between consecutive audits or at the next scheduled monitoring survey if a camera operator is not scheduled to perform an OGI survey during the semiannual period.
Camera Operator Training	Field retraining	Meet the requirements of Section 10.4.3 while maintaining the records of survey hours by the trainee along with a certificate or record of completion issued upon passing the final monitoring survey test in Section 10.2.2.4 with the date of the survey recorded	After failing to meet the benchmarks in Section 10.4.1.2 or 10.4.2.2 during a semiannual audit or after a prolonged period (greater than 12 months) of not performing OGI surveys. May be substituted for initial field training as noted in Section 10.6.2.
OGI Camera Operator Performance	QA verification video	Record a video that is a minimum of 5 minutes long that documents the procedures the operator uses to survey (*e.g.,* dwell times, angles, distances, backgrounds) and the camera configuration	Each monitoring day.

12.0 Recordkeeping

12.1 Records must be kept for a period of 5 years, unless otherwise noted below or otherwise specified in a referencing subpart. Records may be retained in hard copy or electronic form.

12.2 The facility must maintain the following records in a manner that is easily accessible to all OGI camera operators. These records must be retained for as long as the site performs OGI surveys. Older versions of these records that are no longer relevant because they have been replaced by newer versions must be retained for a period of 5 years past the date on which they are replaced.

12.2.1 Complete site monitoring plan with all the required elements.

12.2.2 The OGI camera operating envelope limitations.

12.3 All data supporting the OGI camera specification confirmation (initially and updated as required in Section 8.1) and development of the operating envelope. While the owner or operator does not need to have a copy of these records onsite if another entity performed the camera specification confirmation or development of the operating envelope, the owner or operator must:

(1) Ensure that the camera specification confirmation and development of the operating envelope were performed in accordance with the requirements of this appendix K,

(2) Ensure easy access to these records, and

(3) Make the records available for review if requested by the Administrator.

These records must be retained for the entire period that the OGI camera is used to conduct surveys at the site plus 5 years.

12.4 The training plan for OGI camera operators. The plan must be retained for as long as the site performs OGI surveys. Older versions of the plan that are no longer relevant because they have been replaced by a newer version must be retained for a period of 5 years past the date on which they are replaced. If the facility does not perform its own OGI monitoring, the owner or operator must:

(1) Ensure that the training plan for the company performing the OGI surveys adheres to the requirements of this appendix K,

(2) Ensure easy access to the plan, and

(3) Make the plan available for review if requested by the Administrator.

12.5 For each OGI camera operator, the following records. These may be kept in a separate location for privacy but must be easily accessible to program administrators and available for review if requested by the Administrator. It may be necessary to retain the records in Section 12.5.3 for longer than 5 years to show the career experience survey hours for senior OGI camera operators. If the facility does not perform its own OGI monitoring, the owner or operator must:

(1) Ensure that the training plan for the company performing the OGI surveys adheres to the requirements of this appendix K,

(2) Be able to easily access these records, and

(3) Make the records available for review if requested by the Administrator.

The records must include the following information.

12.5.1 The date of completion of initial OGI camera operator classroom training;

12.5.2 The date of the passed final site survey test following the initial OGI camera operator field training or retraining;

12.5.3 The number and date of all surveys performed, and if the survey is part of initial field training or retraining, the amount of survey hours and notation of whether the survey was performed by observing a senior OGI camera operator, side-by-side with a senior OGI camera operator, or with oversight from a senior OGI camera operator;

12.5.4 The date and results of semiannual performance audits;

12.5.5 The date of the biennial classroom training refresher; and

12.5.6 Documentation to support the use of previous experience as a substitution for initial training requirements, including the date of previous classroom training and documentation of survey hours over the 12 calendar months prior to March 8, 2024, as appropriate.

12.6 Monitoring survey results shall be kept in a manner that is accessible to those technicians executing repairs and at a minimum must contain the following:

12.6.1 Daily verification check;

12.6.2 Identification of the site surveyed, the survey date, and the start and end times of the survey;

12.6.3 Name of the OGI camera operator performing the survey and identification of the OGI camera used to conduct the survey. The identification of the OGI camera can be the serial number or an assigned name/number labeled on the camera, but it must allow an operator or inspector to tie the camera back to the records associated with the camera (*e.g.,* maintenance, initial specification confirmation);

12.6.4 Weather conditions, including the ambient temperature, wind speed, relative humidity, and sky conditions, at the start and end of the survey and every two hours (if the survey exceeded four hours in length);

12.6.5 Video footage or photograph of any leak detected, or video footage of the entire survey, along with the date, time, and location of the leak, and identification of the component associated with the leak;

12.6.6 The daily QA verification video for each operator; and

12.6.7 GPS coordinates for the route taken, if Section 9.3.3 is used to ensure all components regulated by the referencing subpart are monitored.

12.7 For each instance that an OGI camera operator uses the daily field check outlined in Section 8.7 instead of an operating enveloped established under Section 8, the following records must be kept with the monitoring survey records required by Section 12.6.

12.7.1 Date and time of each daily field check.

12.7.2 Video record of the daily field check.

12.7.3 Maximum viewing distance determined for each test gas in each configuration for each OGI camera operator. The overall maximum viewing distance (or overall maximum viewing distance per configuration) that will be used for the monitoring day for each OGI camera operator.

12.7.4 The delta-T and wind speed at the time of the daily field check.

12.7.5 Documentation of the test gas flow rate and concentrations during the daily field check.

12.8 Camera maintenance and calibration records over the entire period that the OGI camera is used to conduct surveys at the site. Older versions of these records that are no longer relevant because they have been replaced by newer versions must be retained for a period of 5 years past the date on which they are replaced. If the facility does not perform its own OGI monitoring, the owner or operator must be able to easily access these records and must make the records available for review if requested by the Administrator.

13.0 References

13.1 U.S. Department of Health and Human Services. (2010). NIOSH Pocket Guide to Chemical Hazards. NIOSH Publication No. 2010-168c. Also available from *https://www.cdc.gov/niosh/docs/2010-168c/default.html*.

13.2 U.S. Environmental Protection Agency. (2023). Technical Support Document: Optical Gas Imaging Protocol (Appendix K to this part).

13.3 U.S. Environmental Protection Agency. (2020). Optical Gas Imaging Stakeholder Input Workshop Presentations and Discussion; Summary Letter Report.

13.4 Zimmerle, D., T. Vaughn, C. Bell, K. Bennett, P. Deshmukh, and E. Thoma. (2020). Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions. *Environmental Science & Technology, 54*(18), 11506-11514. DOI: 10.1021/acs.est.0c01285.

14.0 Annexes

14.1 Annex 1—Development of Response Factors for OGI Cameras.

14.1.1 Introduction.

The purpose of this annex 14.1 is to outline the protocol for the development of response factors (RFs) for optical gas imaging (OGI) cameras. As defined in Section 3.0 of this appendix K, a response factor is the OGI camera's response to a compound of interest relative to a reference compound at a concentration path-length of 10,000 parts per million-meter (ppm-m).

14.1.1.1 Nomenclature.

14.1.1.1.1 The definitions listed in Section 3.0 of this appendix K apply to this annex 14.1.

14.1.1.1.2 Infrared (IR) radiance pixel area. The IR radiance pixel area is the average of a set of pixel IR radiance for an instantaneous measurement. There will be three different areas representing the reference cell, gas cell, and the raw blackbody surface. The pixel count for each area must be at a minimum of 0.5 percent of the total pixels of the detector. The pixel locations selected for an area must not change throughout the test.

14.1.1.1.3 Measurement data set. Measurement data set is the number of time independent IR radiance pixel areas that are taken. The minimum number of measured IR radiance pixel area within a data set is 1,000 data points. The number of measured IR radiance pixel area within a measurement data set should stay consistent throughout the test.

14.1.1.1.4 Reference Compound. The reference compound is the compound that provides the reference for determination of the RF with the compound of interest. The reference compound for this annex 14.1 is propane, unless otherwise specified in a referencing subpart.

14.1.2 Applicability and Analytical Principle.

14.1.2.1 Applicability. This annex 14.1 applies to the determination of compound specific RFs through empirical testing for use with this appendix K. This annex 14.1 does not apply to other applications of OGI cameras or other instruments. This annex 14.1 does not limit the use of other peer reviewed and published techniques and RFs per Section 3.0 of this appendix K.

14.1.2.2 Analytical Principle. OGI cameras work by providing an image or video with each pixel representing a measurement of the IR radiation. OGI cameras limit measurement to specific wavelengths of IR through the choice of the detector and generally through the addition of a bandpass filter. Limiting the measurement to specific wavelengths of IR allows the OGI camera to focus on a specific region of interest in order to increase the detection capabilities of particular compounds of interest. The combination of detector and bandpass filter, in addition to limiting the region of interest, will allow varying amounts of IR over the specific wavelength region.

14.1.3.0 Equipment and Supplies.

14.1.3.1 Section 6.0 of this appendix K lists equipment and supplies that may be used in this annex 14.1.

14.1.3.2 Blackbody Source. A sufficiently large blackbody source capable of maintaining high emissivity, as well as temperature stability and homogeneity.

14.1.3.2.1 The blackbody must have an emissivity of 0.95 or higher in the IR region of interest.

14.1.3.2.2 The source emissive area must have a uniform temperature, where uniform is defined as all points on the emissive area deviating no more than 0.10 degree Celsius (°C) from the average temperature of the emissive area. The temperature readings must be accurate to at least 0.10 °C. The blackbody must be able to maintain its temperature within 0.10 °C.

14.1.3.2.3 The source's surface area must be large enough to allow the OGI camera to take IR measurements of two gas cells and allow for the proper measurement of IR radiance through the gas and reference cell and IR radiance of the surface itself.

14.1.3.3 Test gas for each compound of interest, used for determining the RF. The concentration of the gas in the cylinder must be vendor certified to ± 5.0 percent of the cylinder tag value and be in a balance of nitrogen. The concentration of the gas must be such that the gas cell concentration is 10,000 ppm-m with less than 2.0 percent error. Alternatively, the gas standard may be produced with dilution per Method 205 of 40 CFR part 51 Appendix M with the exception that the mid-supply gas may be vendor certified to ± 5.0 percent of the cylinder tag value.

14.1.3.4 Gas Cell. A windowed gas cell that is leak tight and has the ability to flow gas through the cell. The size of the cell should be such to allow for 10,000 ppm-m to be viewed by the OGI camera with less than 2.0 percent error. The windows should be 99 percent transmissive in the IR region of interest and deviate no more than 0.50 percent transmission over than region of interest. The cell must have associated temperature, flow, and pressure measurements.

14.1.3.5 Reference Compound Gas Standard. Propane gas standard, unless a referencing subpart specifies otherwise, used as the reference for determination of the RF. The concentration of the gas in the cylinder must be vendor certified to ± 2.0 percent of the cylinder tag value and be in a balance of nitrogen. The concentration of the gas must be such that the gas cell concentration is 10,000. ppm-m with less than 2.0 percent error.

14.1.3.6 Reference Cell. A gas cell for the reference compound gas standard which meets all of the requirements in Section 14.1.3.4 of this annex 14.1.

14.1.3.7 Zero Gas. A 99.99 percent pure diatomic gas, typically nitrogen, that has no IR response from the OGI camera, used to assess the detection level of the system and baseline response of the gas cells.

14.1.3.8 OGI Camera is the specific OGI camera that is being tested. RFs must be determined for each IR detector and bandpass filter combination. The OGI camera must have the ability to output the raw IR radiance at the pixel level.

14.1.3.8.1 The combination of IR detector and bandpass filter may be consistent over several models such that the developed RFs may be applicable to more than one model of OGI camera.

14.1.3.8.2 If the OGI camera model has exchangeable bandpass filters, more than one set of RFs may be needed for the OGI camera model to account for the differences between filters.

4.0 Pre-Test Preparation and Evaluations.

14.1.4.1 Room Preparation. The room where testing will occur must be prepared by removing all extraneous thermal sources, or at a minimum, isolating extraneous thermal sources with IR absorptive material before any testing is conducted.

14.1.4.2 Reference and Gas Cell Preparation. Perform leak checks on both the reference and gas cells. Ensure that the temperatures of the cells are within 0.10 °C and that the pressure measurements are working.

14.1.4.3 OGI Camera Preparation. Ensure the OGI camera is operating to manufacturer specifications and able to record in raw IR radiance on a per pixel basis.

14.1.4.4 Blackbody Preparation and Verification. Prepare the blackbody by setting the temperature 10.0 °C different than the gas and reference cell temperatures. Ensure the blackbody is working correctly by verifying the IR radiance homogeneity of the blackbody surface with the OGI camera.

14.1.4.5 System Preparation. Ensure the alignment of the cells, blackbody source, and OGI camera are all fixed in place and cannot deviate from their position during the testing.

14.1.4.5.1 The reference and gas cell windows must overlap the blackbody surface in a manner that provides sufficient viewing of the blackbody surface from the vantage point of the camera.

14.1.4.5.2 The reference and gas cells should be placed sufficiently away from the blackbody surface. The distance must be far enough to ensure that the reference and gas cells are not heated or cooled by the blackbody surface.

14.1.4.5.3 The OGI camera should be located at a distance such that the field of view allows the requirements of the IR radiance pixel area to be met. Additionally, the distance must be such that it does not nominally change the path length of the cell.

14.1.4.5.4 For both the reference cell and the gas cell, the depth of the cell and concentration of the gas must result in a concentration 10,000. ppm-m with less than 2 percent error.

14.1.4.6 Initial System Assessment.

14.1.4.6.1 Flow zero gas through both the reference and gas cell, and ensure the gas cell temperatures are within 0.1 °C.

14.1.4.6.2 Record the temperatures of the gas and reference cells, the blackbody surface, and the room. Record the pressures in the reference and gas cells. Record the flowrates into the reference and gas cells.

14.1.4.6.3 Measure the IR radiance of the reference cell, the gas cell, and the blackbody surface for a measurement data set. For the IR radiance pixel area for the blackbody, the blackbody through the reference cell, and the blackbody through the gas cell, calculate the average, the standard deviation, and the 99 percent confidence level for the measurement data set.

14.1.4.6.4 The detection limit for the system will be the highest 99 percent confidence level of the IR radiance measurement of the blackbody, blackbody through the reference cell, or blackbody through the gas cell.

14.1.4.6.5 If the standard deviation of the reference cell's and the gas cell's average pixel areas of interest have a difference greater than 5 percent, take corrective actions and repeat the assessment.

14.1.5.0 Sampling and Analysis Procedure.

14.1.5.1 Flow reference compound gas through the reference cell and test gas for the compound of interest through the gas cell and ensure the cell temperatures are within 0.10 °C.

14.1.5.2 Record the temperatures of the gas and reference cells, the blackbody surface, and the room temperature. Record the pressures in the reference and gas cells. Record the flowrates into the reference and gas cells. If using Method 205 of 40 CFR part 51 Appendix M for dilution of the test gas for the compound of interest, record the appropriate parameters required by the method.

14.1.5.3 Adjust the gas flow if the pressure in the cell is not within an inch of water of ambient pressure. Ensure cell temperatures are within 0.10 °C of the room temperature.

14.1.5.4 Measure the IR radiance of the reference cell, the gas cell, and the blackbody surface for a measurement data set. Calculate the average of the IR radiance pixel area and the standard deviation of the IR radiance pixel area for the reference cell, gas cell, and the blackbody surface for the measurement data set.

14.1.6.0 Post-test Requirements.

14.1.6.1 Post-test Assessment.

14.1.6.1.1 Flow zero gas through both the reference and gas cells and ensure the cell temperatures are within 0.1 °C.

14.1.6.1.2 Record the temperatures of the gas and reference cells, the blackbody surface, and the room. Record the pressures in the reference and gas cells. Record the flowrates into the reference and gas cells.

14.1.6.1.3 Measure the IR radiance of the reference cell, the gas cell, and the blackbody surface for a measurement data set. Calculate the average of the IR radiance pixel area, the standard deviation of the IR radiance pixel area, and the 99 percent confidence level of the IR radiance pixel area for the reference cell, gas cell, and the blackbody surface for the measurement data set.

14.1.6.1.4 If the average and standard deviation of the reference cell's and the gas cell's average pixel areas of interest have a difference greater than 5.0 percent between the pre-test and post-test assessment, then the test is invalid. Take corrective actions and repeat the test.

14.1.6.2 When the average of the IR radiance pixel areas for the compound of interest over the measurement set as determined in Section 14.1.5.4 of this annex 14.1 is greater than the detection limit established in Section 14.1.4.6.4 of this annex 14.1, calculate the RF for the compound of interest as follows:

$$RF = \frac{I_{Blackbody-}\left(I_{Compound\ of\ Interest} - I_{Gas\ Cell}\right)}{I_{Blackbody-}\left(I_{Reference\ Compound} - I_{Reference\ Cell}\right)}$$

RF = response factor of the compound of interest (unitless).

$I_{Blackbody}$ = average of the IR radiance pixel areas for the blackbody over the measurement set as determined in Section 14.1.4.6.3 of this annex 14.1, $W{\cdot}m^{-2}{\cdot}sr^{-1}$ (watts per square meter per steradian).

$I_{Compound\ of\ interest}$ = average of the IR radiance pixel areas for the compound of interest over the measurement set as determined in Section 14.1.5.4 of this annex 14.1, $W{\cdot}m^{-2}{\cdot}sr^{-1}$.

$I_{Gas\ Cell}$ = average of the IR radiance pixel areas for the gas cell over the measurement set during the pre-test assessment as determined in Section 14.1.4.6.3 of this annex 14.1, $W{\cdot}m^{-2}{\cdot}sr^{-1}$.

$I_{Reference\ Compound}$ = average of the IR radiance pixel areas for the reference compound over the measurement set as determined in Section 14.1.5.4 of this annex 14.1, $W{\cdot}m^{-2}{\cdot}sr^{-1}$.

$I_{Reference\ Cell}$ = average of the IR radiance pixel areas for the reference cell over the measurement set during the pre-test assessment as determined in Section 14.1.4.6.3 of this annex 14.1, $W{\cdot}m^{-2}{\cdot}sr^{-1}$.

14.1.6.3 When the average of the IR radiance pixel areas for the compound of interest over the measurement set as determined in Section 14.1.5.4 of this annex 14.1 is less than the detection limit established in Section 14.1.4.6.4 of this annex 14.1, the RF is equal to zero.

14.1.7.0 Reporting and Recordkeeping Requirements.

14.1.7.1 Records, including all raw data and calculations, must be kept for a period of 5 years, unless otherwise noted below or otherwise specified in a referencing subpart. Records may be retained in hard copy or electronic form.

14.1.7.2 All records supporting the development of RFs under this annex 14.1 must be maintained in a manner that is easily accessible to all OGI camera operators using the RFs. While the owner or operator does not need to have a copy of these records onsite if another entity performed the development of the RFs, the owner or operator must:

(1) Ensure that the RF development was performed in accordance with the requirements of this annex,

(2) Ensure easy access to these records, and

(3) Make the records available for review if requested by the Administrator.

These records must be retained for the entire period that the OGI camera is used to conduct surveys at the site plus 5 years. Previous versions of these records that are no longer relevant because they have been replaced by newer versions or because the specific OGI camera model is no longer being used to conduct surveys at the site must be retained for a period of 5 years past the date on which the records are replaced or the OGI camera model is no longer being used to conduct surveys at the site.

14.1.8.0 References.

14.1.8.1 U.S. Environmental Protection Agency. (2023). Technical Support Document: Optical Gas Imaging Protocol (appendix K to this part).

[89 FR 17219, Mar. 8, 2024]

Title 40 —Protection of Environment
Chapter I —Environmental Protection Agency
Subchapter C —Air Programs
Part 60 —Standards of Performance for New Stationary Sources

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

Source: 36 FR 24877, Dec. 23, 1971, unless otherwise noted.

Subpart A—General Provisions

§ 60.1 Applicability.

(a) Except as provided in subparts B, Ba, and C of this part, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution control agency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (Act) as amended November 15, 1990 (42 U.S.C. 7661). For more information about obtaining an operating permit see part 70 of this chapter.

(d) ***Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.***

(1) This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia (“site”).

(2) Except for compliance with 40 CFR 60.49b(u), the site shall have the option of either complying directly with the requirements of this part, or reducing the site-wide emissions caps in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site chooses the option of reducing the site-wide emissions caps in accordance with the procedures set forth in such permit, the requirements of such permit shall apply in lieu of the otherwise applicable requirements of this part.

(3) Notwithstanding the provisions of paragraph (d)(2) of this section, for any provisions of this part except for Subpart Kb, the owner/operator of the site shall comply with the applicable provisions of this part if the Administrator determines that compliance with the provisions of this part is necessary for achieving the objectives of the regulation and the Administrator notifies the site in accordance with the provisions of the permit issued pursuant to 40 CFR 52.2454.

[40 FR 53346, Nov. 17, 1975, as amended at 55 FR 51382, Dec. 13, 1990; 59 FR 12427, Mar. 16, 1994; 62 FR 52641, Oct. 8, 1997; 88 FR 80542, Nov. 17, 2023]

§ 60.2 Definitions.

The terms used in this part are defined in the Act or in this section as follows:

Act means the Clean Air Act (42 U.S.C. 7401 *et seq.*)

Administrator means the Administrator of the Environmental Protection Agency or his authorized representative.

Affected facility means, with reference to a stationary source, any apparatus to which a standard is applicable.

Alternative method means any method of sampling and analyzing for an air pollutant which is not a reference or equivalent method but which has been demonstrated to the Administrator's satisfaction to, in specific cases, produce results adequate for his determination of compliance.

Approved permit program means a State permit program approved by the Administrator as meeting the requirements of part 70 of this chapter or a Federal permit program established in this chapter pursuant to Title V of the Act (42 U.S.C. 7661).

Capital expenditure means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable “annual asset guideline repair allowance percentage” specified in the latest edition of Internal Revenue Service (IRS) Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code. However, the total expenditure for a physical or operational change to an existing facility must not be reduced by any “excluded additions” as defined in IRS Publication 534, as would be done for tax purposes.

Clean coal technology demonstration project means a project using funds appropriated under the heading ‘Department of Energy-Clean Coal Technology’, up to a total amount of $2,500,000,000 for commercial demonstrations of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency.

Commenced means, with respect to the definition of *new source* in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

Construction means fabrication, erection, or installation of an affected facility.

Continuous monitoring system means the total equipment, required under the emission monitoring sections in applicable subparts, used to sample and condition (if applicable), to analyze, and to provide a permanent record of emissions or process parameters.

Electric utility steam generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

Equivalent method means any method of sampling and analyzing for an air pollutant which has been demonstrated to the Administrator's satisfaction to have a consistent and quantitatively known relationship to the reference method, under specified conditions.

Excess Emissions and Monitoring Systems Performance Report is a report that must be submitted periodically by a source in order to provide data on its compliance with stated emission limits and operating parameters, and on the performance of its monitoring systems.

Existing facility means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type.

Force majeure means, for purposes of § 60.8, 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 the owner or operator from complying with the regulatory requirement to conduct performance tests within the specified timeframe despite the affected facility's best efforts to fulfill the obligation. Examples of such events are acts of nature, acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility.

Isokinetic sampling means sampling in which the linear velocity of the gas entering the sampling nozzle is equal to that of the undisturbed gas stream at the sample point.

Issuance of a part 70 permit will occur, if the State is the permitting authority, in accordance with the requirements of part 70 of this chapter and the applicable, approved State permit program. When the EPA is the permitting authority, issuance of a Title V permit occurs immediately after the EPA takes final action on the final permit.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Modification means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

Monitoring device means the total equipment, required under the monitoring of operations sections in applicable subparts, used to measure and record (if applicable) process parameters.

Nitrogen oxides means all oxides of nitrogen except nitrous oxide, as measured by test methods set forth in this part.

One-hour period means any 60-minute period commencing on the hour.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Owner or operator means any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part.

Part 70 permit means any permit issued, renewed, or revised pursuant to part 70 of this chapter.

Particulate matter means any finely divided solid or liquid material, other than uncombined water, as measured by the reference methods specified under each applicable subpart, or an equivalent or alternative method.

Permit program means a comprehensive State operating permit system established pursuant to title V of the Act (42 U.S.C. 7661) and regulations codified in part 70 of this chapter and applicable State regulations, or a comprehensive Federal operating permit system established pursuant to title V of the Act and regulations codified in this chapter.

Permitting authority means:

(1) The State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to carry out a permit program under part 70 of this chapter; or

(2) The Administrator, in the case of EPA-implemented permit programs under title V of the Act (42 U.S.C. 7661).

Proportional sampling means sampling at a rate that produces a constant ratio of sampling rate to stack gas flow rate.

Reactivation of a very clean coal-fired electric utility steam generating unit means any physical change or change in the method of operation associated with the commencement of commercial operations by a coal-fired utility unit after a period of discontinued operation where the unit:

(1) Has not been in operation for the two-year period prior to the enactment of the Clean Air Act Amendments of 1990, and the emissions from such unit continue to be carried in the permitting authority's emissions inventory at the time of enactment;

(2) Was equipped prior to shut-down with a continuous system of emissions control that achieves a removal efficiency for sulfur dioxide of no less than 85 percent and a removal efficiency for particulates of no less than 98 percent;

(3) Is equipped with low-NO_X burners prior to the time of commencement of operations following reactivation; and

(4) Is otherwise in compliance with the requirements of the Clean Air Act.

Reference method means any method of sampling and analyzing for an air pollutant as specified in the applicable subpart.

Repowering means replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of November 15, 1990. Repowering shall also include any oil and/or gas-fired unit which has been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.

Run means the net period of time during which an emission sample is collected. Unless otherwise specified, a run may be either intermittent or continuous within the limits of good engineering practice.

Shutdown means the cessation of operation of an affected facility for any purpose.

Six-minute period means any one of the 10 equal parts of a one-hour period.

Standard means a standard of performance proposed or promulgated under this part.

Standard conditions means a temperature of 293 K (68F) and a pressure of 101.3 kilopascals (29.92 in Hg).

Startup means the setting in operation of an affected facility for any purpose.

State means all non-Federal authorities, including local agencies, interstate associations, and State-wide programs, that have delegated authority to implement:

(1) The provisions of this part; and/or

(2) the permit program established under part 70 of this chapter. The term State shall have its conventional meaning where clear from the context.

Stationary source means any building, structure, facility, or installation which emits or may emit any air pollutant.

Title V permit means any permit issued, renewed, or revised pursuant to Federal or State regulations established to implement title V of the Act (42 U.S.C. 7661). A title V permit issued by a State permitting authority is called a part 70 permit in this part.

Volatile Organic Compound means any organic compound which participates in atmospheric photochemical reactions; or which is measured by a reference method, an equivalent method, an alternative method, or which is determined by procedures specified under any subpart.

[44 FR 55173, Sept. 25, 1979, as amended at 45 FR 5617, Jan. 23, 1980; 45 FR 85415, Dec. 24, 1980; 54 FR 6662, Feb. 14, 1989; 55 FR 51382, Dec. 13, 1990; 57 FR 32338, July 21, 1992; 59 FR 12427, Mar. 16, 1994; 72 FR 27442, May 16, 2007]

§ 60.3 Units and abbreviations.

Used in this part are abbreviations and symbols of units of measure. These are defined as follows:

(a) System International (SI) units of measure:

A—ampere

g—gram

Hz—hertz

J—joule

K—degree Kelvin

kg—kilogram

m—meter

m^3—cubic meter

mg—milligram—10^{-3} gram

mm—millimeter—10^{-3} meter

Mg—megagram—10^6 gram

mol—mole

N—newton

ng—nanogram—10^{-9} gram

nm—nanometer—10^{-9} meter

Pa—pascal

s—second

V—volt

W—watt

Ω—ohm

μg—microgram—10^{-6} gram

(b) Other units of measure:

Btu—British thermal unit

°C—degree Celsius (centigrade)

cal—calorie

cfm—cubic feet per minute

cu ft—cubic feet

dcf—dry cubic feet

dcm—dry cubic meter

dscf—dry cubic feet at standard conditions

dscm—dry cubic meter at standard conditions

eq—equivalent

°F—degree Fahrenheit

ft—feet

gal—gallon

gr—grain

g-eq—gram equivalent

hr—hour

in—inch

k—1,000

l—liter

lpm—liter per minute

lb—pound

meq—milliequivalent

min—minute

ml—milliliter

mol. wt.—molecular weight

ppb—parts per billion

ppm—parts per million

psia—pounds per square inch absolute

psig—pounds per square inch gage

°R—degree Rankine

scf—cubic feet at standard conditions

scfh—cubic feet per hour at standard conditions

scm—cubic meter at standard conditions

sec—second

sq ft—square feet

std—at standard conditions

(c) Chemical nomenclature:

CdS—cadmium sulfide

CO—carbon monoxide

CO_2—carbon dioxide

HCl—hydrochloric acid

Hg—mercury

H_2O—water

H_2S—hydrogen sulfide

H_2SO_4—sulfuric acid

N_2—nitrogen

NO—nitric oxide

NO_2—nitrogen dioxide

NO_X—nitrogen oxides

O_2—oxygen

SO_2—sulfur dioxide

SO_3—sulfur trioxide

SO_X—sulfur oxides

(d) Miscellaneous:

A.S.T.M.—American Society for Testing and Materials

[42 FR 37000, July 19, 1977; 42 FR 38178, July 27, 1977]

§ 60.4 Address.

(a) All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate to the appropriate Regional Office of the U.S. Environmental Protection Agency to the attention of the Director of the Division indicated in the following list of EPA Regional Offices.

Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont) Director, Enforcement and Compliance Assurance Division, U.S. EPA Region I, 5 Post Office Square—Suite 100 (04-2), Boston, MA 02109-3912, Attn: Air Compliance Clerk.

Region II (New Jersey, New York, Puerto Rico, Virgin Islands), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, Federal Office Building, 26 Federal Plaza (Foley Square), New York, NY 10278.

Region III (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia), Director, Air Protection Division, Mail Code 3AP00, 1650 Arch Street, Philadelphia, PA 19103-2029.

Region IV (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee), Director, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, 61 Forsyth St. SW., Suite 9T43, Atlanta, Georgia 30303-8960.

Region V (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin), Director, Air and Radiation Division, U.S. Environmental Protection Agency, 77 West Jackson Boulevard, Chicago, IL 60604-3590.

Region VI (Arkansas, Louisiana, New Mexico, Oklahoma, Texas); Director; Enforcement and Compliance Assurance Division; U.S. Environmental Protection Agency, 1201 Elm Street, Suite 500, Mail Code 6ECD, Dallas, Texas 75270-2102.

Region VII (Iowa, Kansas, Missouri, Nebraska), Director, Air and Waste Management Division, 11201 Renner Boulevard, Lenexa, Kansas 66219.

Region VIII (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming) Director, Air and Toxics Technical Enforcement Program, Office of Enforcement, Compliance and Environmental Justice, Mail Code 8ENF-AT, 1595 Wynkoop Street, Denver, CO 80202-1129.

Region IX (Arizona, California, Hawaii and Nevada; the territories of American Samoa and Guam; the Commonwealth of the Northern Mariana Islands; the territories of Baker Island, Howland Island, Jarvis Island, Johnston Atoll, Kingman Reef, Midway Atoll, Palmyra Atoll, and Wake Islands; and certain U.S. Government activities in the freely associated states of the Republic of the Marshall Islands, the Federated States of Micronesia, and the Republic of Palau): Director, Enforcement and Compliance Assurance Division (ENF 2-1), U.S. Environmental Protection Agency Region IX, 75 Hawthorne Street, San Francisco, CA 94105.

Region X (Alaska, Oregon, Idaho, Washington), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, 1200 Sixth Avenue, Seattle, WA 98101.

(b) Section 111(c) directs the Administrator to delegate to each State, when appropriate, the authority to implement and enforce standards of performance for new stationary sources located in such State. All information required to be submitted to EPA under paragraph (a) of this section, must also be submitted to the appropriate State Agency of any State to which this authority has been delegated (provided, that each specific delegation may except sources from a certain Federal or State reporting requirement). The appropriate mailing address for those States whose delegation request has been approved is as follows:

(1) [Reserved]

(2) State of Alabama: Alabama Department of Environmental Management, P.O. Box 301463, Montgomery, Alabama 36130-1463.

(3) State of Alaska, Department of Environmental Conservation, Pouch O, Juneau, AK 99811.

(4) Arizona:

Arizona Department of Environmental Quality, Suite #160, 1110 West Washington Street, Phoenix, AZ 85007.

Maricopa County Air Quality Department, 301 West Jefferson Street, Phoenix, AZ 85003.

Pima County Department of Environmental Quality, 33 North Stone Avenue, Suite 700, Tucson, AZ 85701.

Pinal County Air Quality Department, 31 North Pinal Street, Building F, Florence, AZ 85132.

Note 1 to paragraph (b)(4): For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(5) State of Arkansas: Chief, Division of Air Pollution Control, Arkansas Department of Pollution Control and Ecology, 8001 National Drive, P.O. Box 9583, Little Rock, AR 72209.

(6) California:

Amador Air District, 810 Court Street, Jackson, CA 95642.

Antelope Valley Air Quality Management District, 2551 W Avenue H, Lancaster, CA 93536.

Bay Area Air Quality Management District, 375 Beale Street, Suite 600, San Francisco, CA 94105.

Butte County Air Quality Management District, 629 Entler Avenue, Suite 15, Chico, CA 95928.

Calaveras County Air Pollution Control District, 891 Mountain Ranch Road, Building E, San Andreas, CA 95249.

Colusa County Air Pollution Control District, 100 Sunrise Blvd., Suite A, Colusa, CA 95932-3246.

El Dorado County Air Quality Management District, 330 Fair Lane, Placerville, CA 95667-4100.

Eastern Kern Air Pollution Control District, 2700 “M” Street, Suite 302, Bakersfield, CA 93301-2370.

Feather River Air Quality Management District, 541 Washington Avenue, Yuba City, CA 95991.

Glenn County Air Pollution Control District, 720 N Colusa Street, P.O. Box 351, Willows, CA 95988-0351.

Great Basin Unified Air Pollution Control District, 157 Short Street, Bishop, CA 93514-3537.

Imperial County Air Pollution Control District, 150 South Ninth Street, El Centro, CA 92243-2839.

Lake County Air Quality Management District, 2617 S Main St., Lakeport, CA 95453-5405.

Lassen County Air Pollution Control District, 720 South St., Susanville, CA 96130.

Mariposa County Air Pollution Control District, P.O. Box 5, Mariposa, CA 95338.

Mendocino County Air Quality Management District, 306 E Gobbi Street, Ukiah, CA 95482-5511.

Modoc County Air Pollution Control District, 202 W 4th Street, Alturas, CA 96101.

Mojave Desert Air Quality Management District, 14306 Park Avenue, Victorville, CA 92392-2310.

Monterey Bay Air Resources District, 24580 Silver Cloud Court, Monterey, CA 93940.

North Coast Unified Air Quality Management District, 707 L Street, Eureka, CA 95501-3327.

Northern Sierra Air Quality Management District, 200 Litton Drive, Suite 320, Grass Valley, CA 95945-2509.

Northern Sonoma County Air Pollution Control District, 150 Matheson Street, Healdsburg, CA 95448-4908.

Placer County Air Pollution Control District, 110 Maple Street, Auburn, CA 95603.

Sacramento Metropolitan Air Quality Management District, 777 12th Street, Suite 300, Sacramento, CA 95814-1908.

San Diego County Air Pollution Control District, 10124 Old Grove Road, San Diego, CA 92131-1649.

San Joaquin Valley Air Pollution Control District, 1990 E Gettysburg, Fresno, CA 93726.

San Luis Obispo County Air Pollution Control District, 3433 Roberto Court, San Luis Obispo, CA 93401-7126.

Santa Barbara County Air Pollution Control District, 260 North San Antonio Road, Suite A, Santa Barbara, CA 93110-1315.

Shasta County Air Quality Management District, 1855 Placer Street, Suite 101, Redding, CA 96001-1759.

Siskiyou County Air Pollution Control District, 525 So. Foothill Drive, Yreka, CA 96097-3036.

South Coast Air Quality Management District, 21865 Copley Drive, Diamond Bar, CA 91765-4182.

Tehama County Air Pollution Control District, P.O. Box 1169 (1834 Walnut Street), Red Bluff, CA 96080-0038.

Tuolumne County Air Pollution Control District, 2 South Green St., Sonora, CA 95370-4618.

Ventura County Air Pollution Control District, 4567 Telephone Road, 2nd Floor, Ventura, CA 93003-5417.

Yolo-Solano Air Quality Management District, 1947 Galileo Court, Suite 103, Davis, CA 95618.

Note 2 to paragraph (b)(6): For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(7) State of Colorado, Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80222-1530.

Note: For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(8) State of Connecticut, Compliance Analysis and Coordination Unit, Bureau of Air Management, Department of Energy and Environmental Protection, 79 Elm Street, 5th Floor, Hartford, CT 06106-5127.

(9) State of Delaware, Department of Natural Resources & Environmental Control, 89 Kings Highway, P.O. Box 1401, Dover, Delaware 19903.

(10) District of Columbia, Department of Public Health, Air Quality Division, 51 N Street, NE., Washington, DC 20002.

(11) State of Florida: Florida Department of Environmental Protection, Division of Air Resources Management, 2600 Blair Stone Road, MS 5500, Tallahassee, Florida 32399-2400.

(12) State of Georgia: Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, 4244 International Parkway, Suite 120, Atlanta, Georgia 30354.

(13) Hawaii:

> Clean Air Branch, Hawaii Department of Health, 2827 Waimano Home Road, #130 Pearl City, HI 96782.

Note 4 to paragraph (b)(13): For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(14) State of Idaho, Department of Health and Welfare, Statehouse, Boise, ID 83701.

(15) State of Illinois: Illinois Environmental Protection Agency, 1021 North Grand Avenue East, Springfield, Illinois 62794.

(16) State of Indiana: Indiana Department of Environmental Management, Office of Air Quality, 100 North Senate Avenue, Indianapolis, Indiana 46204.

(17) State of Iowa: Iowa Department of Natural Resources, Environmental Protection Division, Air Quality Bureau, 7900 Hickman Road, Suite 1, Urbandale, IA 50322.

(18) State of Kansas: Kansas Department of Health and Environment, Bureau of Air and Radiation, 1000 S.W. Jackson, Suite 310, Topeka, KS 66612-1366.

(19) Commonwealth of Kentucky: Kentucky Department for Environmental Protection, Division for Air Quality, 300 Sower Boulevard, 2nd Floor, Frankfort, Kentucky 40601 or local agency, Louisville Metro Air Pollution Control District, 701 W. Ormsby Ave., Suite 303, Louisville, Kentucky 40203.

(20) State of Louisiana: Louisiana Department of Environmental Quality, P.O. Box 4301, Baton Rouge, Louisiana 70821-4301.

Note: For a list of delegated standards for Louisiana (excluding Indian country), see paragraph (e)(2) of this section.

(21) State of Maine, Maine Department of Environmental Protection, Bureau of Air Quality, 17 State House Station, Augusta, ME 04333-0017.

(22) State of Maryland, Department of the Environment, 1800 Washington Boulevard, Suite 705, Baltimore, Maryland 21230.

(23) Commonwealth of Massachusetts, Massachusetts Department of Environmental Protection, Division of Air and Climate Programs, One Winter Street, Boston, MA 02108.

(24) State of Michigan: Michigan Department of Natural Resources and Environment, Air Quality Division, P.O. Box 30028, Lansing, Michigan 48909.

(25) State of Minnesota: Minnesota Pollution Control Agency, Division of Air Quality, 520 Lafayette Road North, St. Paul, Minnesota 55155.

(26) State of Mississippi: Hand Deliver or Courier: Mississippi Department of Environmental Quality, Office of Pollution Control, Air Division, 515 East Amite Street, Jackson, Mississippi 39201, Mailing Address: Mississippi Department of Environmental Quality, Office of Pollution Control, Air Division, P.O. Box 2261, Jackson, Mississippi 39225.

(27) State of Missouri: Missouri Department of Natural Resources, Division of Environmental Quality, P.O. Box 176, Jefferson City, MO 65102.

(28) State of Montana, Department of Environmental Quality, 1520 E. 6th Ave., PO Box 200901, Helena, MT 59620-0901.

Note: For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(29) State of Nebraska, Nebraska Department of Environmental Control, P.O. Box 94877, State House Station, Lincoln, NE 68509.

Lincoln-Lancaster County Health Department, Division of Environmental Health, 2200 St. Marys Avenue, Lincoln, NE 68502

(30) Nevada:

Nevada Division of Environmental Protection, 901 South Stewart Street, Suite 4001, Carson City, NV 89701-5249.

Clark County Division of Air Quality, 500 S Grand Central Parkway, 1st Floor, P.O. Box 555210, Las Vegas, NV 89155-5210.

Northern Nevada Public Health, Air Quality Management Division, 1001 E 9th Street, Building B, Reno, NV 89512.

Note 7 to paragraph (b)(30): For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(31) State of New Hampshire, New Hampshire Department of Environmental Services, Air Resources Division, 29 Hazen Drive, P.O. Box 95, Concord, NH 03302-0095.

(32) State of New Jersey: New Jersey Department of Environmental Protection, Division of Environmental Quality, Enforcement Element, John Fitch Plaza, CN-027, Trenton, NJ 08625.

(1) The following table lists the specific source and pollutant categories that have been delegated to the states in Region II. The (X) symbol is used to indicate each category that has been delegated.

	Subpart	State			
		New Jersey	New York	Puerto Rico	Virgin Islands
D	Fossil-Fuel Fired Steam Generators for Which Construction Commenced After August 17, 1971 (Steam Generators and Lignite Fired Steam Generators)	X	X	X	X

	Subpart	State			
		New Jersey	New York	Puerto Rico	Virgin Islands
Da	Electric Utility Steam Generating Units for Which Construction Commenced After September 18, 1978	X		X	
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
E	Incinerators	X	X	X	X
F	Portland Cement Plants	X	X	X	X
G	Nitric Acid Plants	X	X	X	X
H	Sulfuric Acid Plants	X	X	X	X
I	Asphalt Concrete Plants	X	X	X	X
J	Petroleum Refineries—(All Categories)	X	X	X	X
K	Storage Vessels for Petroleum Liquids Constructed After June 11, 1973, and prior to May 19, 1978	X	X	X	X
Ka	Storage Vessels for Petroleum Liquids Constructed After May 18, 1978	X	X	X	
L	Secondary Lead Smelters	X	X	X	X
M	Secondary Brass and Bronze Ingot Production Plants	X	X	X	X
N	Iron and Steel Plants	X	X	X	X
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X	X	X	X
Q	Primary Zinc Smelters	X	X	X	X
R	Primary Lead Smelters	X	X	X	X
S	Primary Aluminum Reduction Plants	X	X	X	X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate	X	X	X	X
Y	Coal Preparation Plants	X	X	X	X
Z	Ferroally Production Facilities	X	X	X	X
AA	Steel Plants: Electric Arc Furnaces	X	X	X	X
AAa	Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels in Steel Plants	X	X	X	
BB	Kraft Pulp Mills	X	X	X	
CC	Glass Manufacturing Plants	X	X	X	
DD	Grain Elevators	X	X	X	
EE	Surface Coating of Metal Furniture	X	X	X	
GG	Stationary Gas Turbines	X	X	X	
HH	Lime Plants	X	X	X	
KK	Lead Acid Battery Manufacturing Plants	X	X		

	Subpart	State			
		New Jersey	New York	Puerto Rico	Virgin Islands
LL	Metallic Mineral Processing Plants	X	X	X	
MM	Automobile and Light-Duty Truck Surface Coating Operations	X	X		
NN	Phosphate Rock Plants	X	X		
PP	Ammonium Sulfate Manufacturing Plants	X	X		
QQ	Graphic Art Industry Publication Rotogravure Printing	X	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	X	
SS	Industrial Surface Coating: Large Appliances	X	X	X	
TT	Metal Coil Surface Coating	X	X	X	
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	
VV	Equipment Leaks of Volatile Organic Compounds in Synthetic Organic Chemical Manufacturing Industry	X		X	
WW	Beverage Can Surface Coating Industry	X	X	X	
XX	Bulk Gasoline Terminals	X	X	X	
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries	X		X	
HHH	Synthetic Fiber Production Facilities	X		X	
JJJ	Petroleum Dry Clearners	X	X	X	
KKK	Equipment Leaks of VOC from Onshore Natural Gas Processing Plants				
LLL	Onshore Natural Gas Processing Plants; SO_2 Emissions		X		
OOO	Nonmetallic Mineral Processing Plants		X	X	
PPP	Wool Fiberglass Insulation Manufacturing Plants		X	X	

(33) State of New Mexico: New Mexico Environment Department, P.O. Box 5469, Santa Fe, New Mexico 87502-5469. Note: For a list of delegated standards for New Mexico (excluding Bernalillo County and Indian country), see paragraph (e)(1) of this section.

(34) New York: New York State Department of Environmental Conservation, 50 Wolf Road Albany, New York 12233, attention: Division of Air Resources.

(35) State of North Carolina: North Carolina Department of Environmental Quality, Division of Air Quality, 1641 Mail Service Center, Raleigh, North Carolina 27699-1641 or local agencies, Forsyth County Office of Environmental Assistance and Protection, 201 North Chestnut Street, Winston-Salem, North Carolina 27101-4120; Mecklenburg County Land Use and Environmental Services Agency, Air Quality, 2145 Suttle Avenue, Charlotte, North Carolina 28208; Western North Carolina Regional Air Quality Agency, 125 S. Lexington Ave., Suite 101, Asheville, North Carolina 28801-3661.

(36) State of North Dakota, North Dakota Department of Environmental Quality, 918 East Divide Avenue, Bismarck, ND 58501-1947.

Note: For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(37) State of Ohio:

(i) Medina, Summit and Portage Counties; Director, Akron Regional Air Quality Management District, 146 South High Street, Room 904, Akron, OH 44308.

(ii) Stark County; Director, Canton City Health Department, Air Pollution Control Division, 420 Market Avenue North, Canton, Ohio 44702-1544.

(iii) Butler, Clermont, Hamilton, and Warren Counties; Director, Hamilton County Department of Environmental Services, 250 William Howard Taft Road, Cincinnati, Ohio 45219-2660.

(iv) Cuyahoga County; Commissioner, Cleveland Department of Public Health, Division of Air Quality, 75 Erieview Plaza 2nd Floor, Cleveland, Ohio 44114.

(v) Clark, Darke, Greene, Miami, Montgomery, and Preble Counties; Director, Regional Air Pollution Control Agency, 117 South Main Street, Dayton, Ohio 45422-1280.

(vi) Lucas County and the City of Rossford (in Wood County); Director, City of Toledo, Division of Environmental Services, 348 South Erie Street, Toledo, OH 43604.

(vii) Adams, Brown, Lawrence, and Scioto Counties; Portsmouth Local Air Agency, 605 Washington Street, Third Floor, Portsmouth, OH 45662.

(viii) Allen, Ashland, Auglaize, Crawford, Defiance, Erie, Fulton, Hancock, Hardin, Henry, Huron, Marion, Mercer, Ottawa, Paulding, Putnam, Richland, Sandusky, Seneca, Van Wert Williams, Wood (Except City of Rossford), and Wyandot Counties; Ohio Environmental Protection Agency, Northwest District Office, Air Pollution Control, 347 North Dunbridge Road, Bowling Green, Ohio 43402.

(ix) Ashtabula, Caroll, Colombiana, Holmes, Lorain, and Wayne Counties; Ohio Environmental Protection Agency, Northeast District Office, Air Pollution Unit, 2110 East Aurora Road, Twinsburg, OH 44087.

(x) Athens, Belmont, Coshocton, Gallia, Guemsey, Harrison, Hocking, Jackson, Jefferson, Meigs, Monroe, Morgan, Muskingum, Noble, Perry, Pike, Ross, Tuscarawas, Vinton, and Washington Counties; Ohio Environmental Protection Agency, Southeast District Office, Air Pollution Unit, 2195 Front Street, Logan, OH 43138.

(xi) Champaign, Clinton, Highland, Logan, and Shelby Counties; Ohio Environmental Protection Agency, Southwest District Office, Air Pollution Unit, 401 East Fifth Street, Dayton, Ohio 45402-2911.

(xii) Delaware, Fairfield, Fayette, Franklin, Knox, Licking, Madison, Morrow, Pickaway, and Union Counties; Ohio Environmental Protection Agency, Central District Office, Air Pollution control, 50 West Town Street, Suite 700, Columbus, Ohio 43215.

(xiii) Geauga and Lake Counties; Lake County General Health District, Air Pollution Control, 33 Mill Street, Painesville, OH 44077.

(xiv) Mahoning and Trumbull Counties; Mahoning-Trumbull Air Pollution Control Agency, 345 Oak Hill Avenue, Suite 200, Youngstown, OH 44502.

(38) State of Oklahoma, Oklahoma State Department of Health, Air Quality Service, P.O. Box 53551, Oklahoma City, OK 73152.

(i) Oklahoma City and County: Director, Oklahoma City-County Health Department, 921 Northeast 23rd Street, Oklahoma City, OK 73105.

(ii) Tulsa County: Tulsa City-County Health Department, 4616 East Fifteenth Street, Tulsa, OK 74112.

(39) State of Oregon.

(i) Oregon Department of Environmental Quality (ODEQ), 811 SW Sixth Avenue, Portland, OR 97204-1390, *http://www.deq.state.or.us*.

(ii) Lane Regional Air Pollution Authority (LRAPA), 1010 Main Street, Springfield, Oregon 97477, *http://www.lrapa.org*.

(40)

(i) City of Philadelphia, Department of Public Health, Air Management Services, 321 University Avenue, Philadelphia, Pennsylvania 19104.

(ii) Commonwealth of Pennsylvania, Department of Environmental Protection, Bureau of Air Quality Control, P.O. Box 8468, 400 Market Street, Harrisburg, Pennsylvania 17105.

(iii) Allegheny County Health Department, Bureau of Environmental Quality, Division of Air Quality, 301 39th Street, Pittsburgh, Pennsylvania 15201.

(41) State of Rhode Island, Rhode Island Department of Environmental Management, Office of Air Resources, 235 Promenade Street, Providence, RI 02908.

(42) State of South Carolina: South Carolina Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201.

(43) State of South Dakota, Air Quality Program, Department of Agriculture and Natural Resources, Joe Foss Building, 523 East Capitol, Pierre, SD 57501-3181.

(44) State of Tennessee: Tennessee Department of Environment and Conservation, Division of Air Pollution Control, William R. Snodgrass Tennessee Tower, 312 Rosa L. Parks Avenue, 15th Floor, Nashville, Tennessee 37243, or local agencies, Knox County Air Quality Management—Department of Public Health, 140 Dameron Avenue, Knoxville, Tennessee 37917; Metro Public Health Department, Pollution Control Division, 2500 Charlotte Ave., Nashville, Tennessee 37209; Chattanooga-Hamilton County Air Pollution Control Bureau, 6125 Preservation Drive, Chattanooga, Tennessee 37416; Shelby County Health Department, Pollution Control Section, 814 Jefferson Avenue, Memphis, Tennessee 38105.

(45) State of Texas, Texas Air Control Board, 6330 Highway 290 East, Austin, TX 78723.

(46) State of Utah, Division of Air Quality, Department of Environmental Quality, P.O. Box 144820, Salt Lake City, UT 84114-4820.

> Note: For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(47) State of Vermont, Agency of Natural Resources, Department of Environmental Conservation, Air Quality and Climate Division, Davis 2, One National Life Drive, Montpelier, VT 05620-3802.

(48) Commonwealth of Virginia, Department of Environmental Quality, 629 East Main Street, Richmond, Virginia 23219.

(49) *State of Washington.*

(i) Washington State Department of Ecology (Ecology), P.O. Box 47600, Olympia, WA 98504-7600, *http://www.ecy.wa.gov/*

(ii) Benton Clean Air Authority (BCAA), 650 George Washington Way, Richland, WA 99352-4289, *http://www.bcaa.net/*

(iii) Northwest Air Pollution Control Authority (NWAPA), 1600 South Second St., Mount Vernon, WA 98273-5202, *http://www.nwair.org/*

(iv) Olympic Regional Clean Air Agency (ORCAA), 909 Sleater-Kinney Road S.E., Suite 1, Lacey, WA 98503-1128, *http://www.orcaa.org/*

(v) Puget Sound Clean Air Agency (PSCAA), 110 Union Street, Suite 500, Seattle, WA 98101-2038, *http://www.pscleanair.org/*

(vi) Spokane County Air Pollution Control Authority (SCAPCA), West 1101 College, Suite 403, Spokane, WA 99201, *http://www.scapca.org/*

(vii) Southwest Clean Air Agency (SWCAA), 1308 NE. 134th St., Vancouver, WA 98685-2747, *http://www.swcleanair.org/*

(viii) Yakima Regional Clean Air Authority (YRCAA), 6 South 2nd Street, Suite 1016, Yakima, WA 98901, *http://co.yakima.wa.us/cleanair/default.htm*

(ix) The following table lists the delegation status of the New Source Performance Standards for the State of Washington. An “X” indicates the subpart has been delegated, subject to all the conditions and limitations set forth in Federal law and the letters granting delegation. Some authorities cannot be delegated and are retained by EPA. Refer to the letters granting delegation for a discussion of these retained authorities. The dates noted at the end of the table indicate the effective dates of Federal rules that have been delegated. Authority for implementing and enforcing any amendments made to these rules after these effective dates are not delegated.

NSPS Subparts Delegated to Washington Air Agencies

Subpart[1]	Washington							
	Ecology[2]	BCAA[3]	NWAPA[4]	ORCAA[5]	PSCAA[6]	SCAPCA[7]	SWCAA[8]	YRCAA[9]
A General Provisions	X	X	X	X	X	X	X	X
B Adoption and Submittal of State Plans for Designated Facilities								
C Emission Guidelines and Compliance Times								
Cb Large Municipal Waste Combustors that are Constructed on or before September 20, 1994 (Emission Guidelines and Compliance Times)								
Cc Municipal Solid Waste Landfills (Emission Guidelines and Compliance Times)								
Cd Sulfuric Acid Production Units (Emission Guidelines and Compliance Times)								
Ce Hospital/Medical/Infectious Waste Incinerators (Emission Guidelines and Compliance Times)								
D Fossil-Fuel-Fired Steam Generators for which Construction is Commenced after August 17, 1971	X	X	X	X	X	X	X	X
Da Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978	X	X	X	X	X	X	X	X
Db Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X	X	X	X	X
Dc Small Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X	X	X	X	X
E Incinerators	X	X	X	X	X	X	X	X
Ea Municipal Waste Combustors for which Construction is Commenced after December 20, 1989 and on or before September 20, 1994	X	X	X	X	X	X	X	X
Eb—Large Municipal Waste Combustors		X		X	X	X		
Ec—Hospital/Medical/Infectious Waste Incinerators	X	X	X	X	X	X		
F Portland Cement Plants	X	X	X	X	X	X	X	X
G Nitric Acid Plants	X	X	X	X	X	X	X	X
H Sulfuric Acid Plants	X	X	X	X	X	X	X	X
I Hot Mix Asphalt Facilities	X	X	X	X	X	X	X	X
J Petroleum Refineries	X	X	X	X	X	X	X	X
K Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced after June 11, 1973 and prior to May 19, 1978	X	X	X	X	X	X	X	X
Ka Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced after May 18, 1978 and prior to July 23, 1984	X	X	X	X	X	X	X	X
Kb VOC Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced after July 23, 1984	X	X	X	X	X	X	X	X
L Secondary Lead Smelters	X	X	X	X	X	X	X	X
M Secondary Brass and Bronze Production Plants	X	X	X	X	X	X	X	X
N Primary Emissions from Basic Oxygen Process Furnaces for which Construction is Commenced after June 11, 1973	X	X	X	X	X	X	X	X

Subpart[1]	Washington							
	Ecology[2]	BCAA[3]	NWAPA[4]	ORCAA[5]	PSCAA[6]	SCAPCA[7]	SWCAA[8]	YRCAA[9]
Na Secondary Emissions from Basic Oxygen Process Steel-making Facilities for which Construction is Commenced after January 20, 1983	X	X	X	X	X	X	X	X
O Sewage Treatment Plants	X	X	X	X	X	X	X	X
P Primary Copper Smelters	X	X	X	X	X	X	X	X
Q Primary Zinc Smelters	X	X	X	X	X	X	X	X
R Primary Lead Smelters	X	X	X	X	X	X	X	X
S Primary Aluminum Reduction Plants[10]	X							
T Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	X	X	X	X	X
U Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	X	X	X	X	X
V Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	X	X	X	X	X
W Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	X	X	X	X	X
X Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X	X	X	X	X	X	X	X
Y Coal Preparation Plants	X	X	X	X	X	X	X	X
Z Ferroalloy Production Facilities	X	X	X	X	X	X	X	X
AA Steel Plants: Electric Arc Furnaces Constructed after October 21, 1974 and on or before August 17, 1983	X	X	X	X	X	X	X	X
AAa Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed after August 7, 1983	X	X	X	X	X	X	X	X
BB Kraft Pulp Mills[11]	X							
CC Glass Manufacturing Plants	X	X	X	X	X	X	X	X
DD Grain Elevators	X	X	X	X	X	X	X	X
EE Surface Coating of Metal Furniture	X	X	X	X	X	X	X	X
GG Stationary Gas Turbines	X	X	X	X	X	X	X	X
HH Lime Manufacturing Plants	X	X	X	X	X	X	X	X
KK Lead-Acid Battery Manufacturing Plants	X	X	X	X	X	X	X	X
LL Metallic Mineral Processing Plants	X	X	X	X	X	X	X	X
MM Automobile and Light Duty Truck Surface Coating Operations	X	X	X	X	X	X	X	X
NN Phosphate Rock Plants	X	X	X	X	X	X	X	X
PP Ammonium Sulfate Manufacture	X	X	X	X	X	X	X	X
QQ Graphic Arts Industry: Publication Rotogravure Printing	X	X	X	X	X	X	X	X
RR Pressure Sensitive Tape and Label Surface Coating Standards	X	X	X	X	X	X	X	X
SS Industrial Surface Coating: Large Appliances	X	X	X	X	X	X	X	X
TT Metal Coil Surface Coating	X	X	X	X	X	X	X	X
UU Asphalt Processing and Asphalt Roof Manufacture	X	X	X	X	X	X	X	X

Subpart[1]	Washington							
	Ecology[2]	BCAA[3]	NWAPA[4]	ORCAA[5]	PSCAA[6]	SCAPCA[7]	SWCAA[8]	YRCAA[9]
VV Equipment Leaks of VOC in Synthetic Organic Chemical Manufacturing Industry	X	X	X	X	X	X	X	X
WW Beverage Can Surface Coating Industry	X	X	X	X	X	X	X	X
XX Bulk Gasoline Terminals	X	X	X	X	X	X	X	X
AAA New Residential Wood Heaters								
BBB Rubber Tire Manufacturing Industry	X	X	X	X	X	X	X	X
DDD VOC Emissions from Polymer Manufacturing Industry	X	X	X	X	X	X	X	X
FFF Flexible Vinyl and Urethane Coating and Printing	X	X	X	X	X	X	X	X
GGG Equipment Leaks of VOC in Petroleum Refineries	X	X	X	X	X	X	X	X
HHH Synthetic Fiber Production Facilities	X	X	X	X	X	X	X	X
III VOC Emissions from Synthetic Organic Chemical Manufacturing Industry Air Oxidation Unit Processes	X	X	X	X	X	X	X	X
JJJ Petroleum Dry Cleaners	X	X	X	X	X	X	X	X
KKK Equipment Leaks of VOC from Onshore Natural Gas Processing Plants	X	X	X	X	X	X	X	X
LLL Onshore Natural Gas Processing: SO_2 Emissions	X	X	X	X	X	X	X	X
NNN VOC Emissions from Synthetic Organic Chemical Manufacturing Industry Distillation Operations	X	X	X	X	X	X	X	X
OOO Nonmetallic Mineral Processing Plants			X		X		X	
PPP Wool Fiberglass Insulation Manufacturing Plants	X	X	X	X	X	X	X	X
QQQ VOC Emissions from Petroleum Refinery Wastewater Systems	X	X	X	X	X	X	X	X
RRR VOCs from Synthetic Organic Chemical Manufacturing Industry Reactor Processes	X	X	X	X	X	X	X	X
SSS Magnetic Tape Coating Facilities	X	X	X	X	X	X	X	X
TTT Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X	X	X	X	X	X
UUU Calciners and Dryers in Mineral Industries	X	X	X	X	X	X	X	X
VVV Polymeric Coating of Supporting Substrates Facilities	X	X	X	X	X	X	X	X
WWW Municipal Solid Waste Landfills	X	X	X	X	X	X	X	X
AAAA Small Municipal Waste Combustion Units for which Construction is Commenced after August 30, 1999 or for which Modification or Reconstruction is Commenced after June 6, 2001	X	X		X	X	X		X
BBBB Small Municipal Waste Combustion Units Constructed on or before August 30, 1999 (Emission Guidelines and Compliance Times)								
CCCC Commercial and Industrial Solid Waste Incineration Units for which Construction is Commenced after November, 30, 1999 or for which Modification or Reconstruction is Commenced on or after June 1, 2001	X	X		X	X	X		X
DDDD Commercial and Industrial Solid Waste Incineration Units that Commenced Construction on or before November 30, 1999 (Emission Guidelines and Compliance Times)								

[1] Any authority within any subpart of this part that is not delegable, is not delegated. Please refer to Attachment B to the delegation letters for a listing of the NSPS authorities excluded from delegation.

[2] Washington State Department of Ecology, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

[3] Benton Clean Air Authority, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

[4] Northwest Air Pollution Authority, for all NSPS delegated, as in effect on July 1, 2000.

[5] Olympic Regional Clean Air Authority, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

[6] Puget Sound Clean Air Authority, for all NSPS delegated, as in effect on July 1, 2002.

[7] Spokane County Air Pollution Control Authority, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

[8] Southwest Clean Air Agency, for all NSPS delegated, as in effect on July 1, 2000.

[9] Yakima Regional Clean Air Authority, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

[10] Subpart S of this part is not delegated to local agencies in Washington because the Washington State Department of Ecology retains sole authority to regulate Primary Aluminum Plants, pursuant to Washington Administrative Code 173-415-010.

[11] Subpart BB of this part is not delegated to local agencies in Washington because the Washington State Department of Ecology retains sole authority to regulate Kraft and Sulfite Pulping Mills, pursuant to Washington State Administrative Code 173-405-012 and 173-410-012.

(50) State of West Virginia, Department of Environmental Protection, Division of Air Quality, 601 57th Street, SE., Charleston, West Virginia 25304.

(51) State of Wisconsin: Wisconsin Department of Natural Resouces, 101 South Webster St., P.O. Box 7921, Madison, Wisconsin 53707-7921.

(52) State of Wyoming, Department of Environmental Quality, Air Quality Division, Herschler Building, 122 West 25th Street, Cheyenne, WY 82002.

> Note: For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(53) Territory of Guam: Guam Environmental Protection Agency, P.O. Box 22439 GMF, Barrigada, Guam 96921.

> Note: For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(54) Commonwealth of Puerto Rico: Commonwealth of Puerto Rico Environmental Quality Board, P.O. Box 11488, Santurce, PR 00910, Attention: Air Quality Area Director (see table under § 60.4(b)(FF)(1)).

(55) U.S. Virgin Islands: U.S. Virgin Islands Department of Conservation and Cultural Affairs, P.O. Box 578, Charlotte Amalie, St. Thomas, VI 00801.

(56) American Samoa: American Samoa Environmental Protection Agency, P.O. Box PPA, Pago Pago, American Samoa 96799.

> Note: For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(57) Commonwealth of the Northern Mariana Islands: CNMI Division of Environmental Quality, P.O. Box 501304, Saipan, MP 96950.

> Note: For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(c) The delegation status table for New Source Performance Standards for Region VIII can be found online at *http://www2.epa.gov/region8/air-program.*

(d) The following tables list the specific part 60 standards that have been delegated unchanged to the air pollution control agencies in Region IX. The (X) symbol is used to indicate each standard that has been delegated. The following provisions of this subpart are not delegated: §§ 60.4(b), 60.8(b), 60.9, 60.11(b), 60.11(e), 60.13(a), 60.13(d)(2), 60.13(g), 60.13(i).

(1) ***Arizona.*** The following table identifies delegations for Arizona:

Table 3 to Paragraph (d)(1)—Delegation Status for New Source Performance Standards for Arizona

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
A	General Provisions	X	X	X	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X	X	X	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
E	Incinerators	X	X	X	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X	X	X	X
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994	X	X	X	
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	X	X	X	
F	Portland Cement Plants	X		X	X
G	Nitric Acid Plants	X	X	X	X
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011		X	X	
H	Sulfuric Acid Plant	X	X	X	X
I	Hot Mix Asphalt Facilities	X	X	X	X
J	Petroleum Refineries	X		X	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007			X	
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X	X	X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X	X	X	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which	X	X	X	X

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
	Construction, Reconstruction, or Modification Commenced After July 23, 1984				
L	Secondary Lead Smelters	X		X	X
M	Secondary Brass and Bronze Production Plants	X	X	X	X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X	X	X	X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X	X	X	X
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X		X	X
Q	Primary Zinc Smelters	X		X	X
R	Primary Lead Smelters	X		X	X
S	Primary Aluminum Reduction Plants	X	X	X	X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X	X	X	X
Y	Coal Preparation and Processing Plants	X	X	X	X
Z	Ferroalloy Production Facilities	X	X	X	X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	X	X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X	X	X	X
BB	Kraft Pulp Mills	X	X	X	X
BBa	Kraft Pulp Mill Sources for which Construction, Reconstruction or Modification Commenced after May 23, 2013		X	X	
CC	Glass Manufacturing Plants	X	X	X	X
DD	Grain Elevators	X	X	X	X
EE	Surface Coating of Metal Furniture	X	X	X	X
FF	(Reserved)				
GG	Stationary Gas Turbines	X	X	X	X

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
HH	Lime Manufacturing Plants	X	X	X	X
KK	Lead-Acid Battery Manufacturing Plants	X	X	X	X
LL	Metallic Mineral Processing Plants	X	X	X	X
MM	Automobile and Light Duty Trucks Surface Coating Operations	X	X	X	X
NN	Phosphate Rock Plants	X	X	X	X
PP	Ammonium Sulfate Manufacture	X	X	X	X
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	X	X
SS	Industrial Surface Coating: Large Appliances	X	X	X	X
TT	Metal Coil Surface Coating	X	X	X	X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	X
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing	X	X	X	X
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006	X	X	X	
WW	Beverage Can Surface Coating Industry	X	X	X	X
XX	Bulk Gasoline Terminals	X	X	X	X
AAA	New Residential Wood Heaters	X	X	X	X
BBB	Rubber Tire Manufacturing Industry	X	X	X	X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X	X	X	X
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	X
GGG	Equipment Leaks of VOC in Petroleum Refineries	X		X	X
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	X		X	
HHH	Synthetic Fiber Production Facilities	X	X	X	X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X	X	X	X
JJJ	Petroleum Dry Cleaners	X	X	X	X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X	X	X	X
LLL	Onshore Natural Gas Processing: SO_2 Emissions	X	X	X	X

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X	X	X	X
OOO	Nonmetallic Mineral Processing Plants	X	X	X	X
PPP	Wool Fiberglass Insulation Manufacturing Plants	X	X	X	X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X		X	X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X	X	X	
SSS	Magnetic Tape Coating Facilities	X	X	X	X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X	X
UUU	Calciners and Dryers in Mineral Industries	X	X	X	
VVV	Polymeric Coating of Supporting Substrates Facilities	X	X	X	X
WWW	Municipal Solid Waste Landfills	X	X	X	
XXX	Municipal Solid Waste Landfills that Commenced Construction, Reconstruction, or Modification After July 17, 2014		X	X	
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commended After June 6, 2001	X	X	X	
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X	X	X	
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006	X	X	X	
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines	X	X	X	
JJJJ	Stationary Spark Ignition Internal Combustion Engines		X	X	
KKKK	Stationary Combustion Turbines	X	X	X	
LLLL	New Sewage Sludge Incineration Units			X	
MMMM	Emissions Guidelines and Compliance Times for Existing Sewage Sludge Incineration Units	X			

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution		X	X	
OOOOa	Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After September 18, 2015		X	X	
QQQQ	Standards of Performance for New Residential Hydronic Heaters and Forced-Air Furnaces		X	X	
TTTT	Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units		X	X	

(2) ***California.*** The following tables identify delegations for each of the local air pollution control agencies of California.

(i) Delegations for Amador County Air Pollution Control District, Antelope Valley Air Quality Management District, Bay Area Air Quality Management District, and Butte County Air Quality Management District are shown in the following table:

Table 4 to Paragraph (d)(2)(i)—Delegation Status for New Source Performance Standards for Amador County APCD, Antelope Valley AQMD, Bay Area AQMD, and Butte County AQMD

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
A	General Provisions		X		
Ba	Adoption and Submittal of State Plans for Designated Facilities		X		
Cf	Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills		X		
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971		X	X	
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978		X	X	
Db	Industrial-Commercial-Institutional Steam Generating Units		X	X	
Dc	Small Industrial-Commercial-Institutional Steam Generating Units		X	X	
E	Incinerators		X	X	
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994		X	X	

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994		X		
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996		X		
F	Portland Cement Plants		X	X	
G	Nitric Acid Plants		X	X	
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011		X		
H	Sulfuric Acid Plant		X	X	
I	Hot Mix Asphalt Facilities		X	X	
J	Petroleum Refineries		X	X	
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007		X		
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978		X	X	
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984		X	X	
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984		X	X	
L	Secondary Lead Smelters		X	X	
M	Secondary Brass and Bronze Production Plants		X	X	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973		X	X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983		X	X	
O	Sewage Treatment Plants		X	X	
P	Primary Copper Smelters		X	X	
Q	Primary Zinc Smelters		X	X	
R	Primary Lead Smelters		X	X	
S	Primary Aluminum Reduction Plants		X	X	

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X		
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X	X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X	X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X	X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities		X	X	
Y	Coal Preparation and Processing Plants		X	X	
Z	Ferroalloy Production Facilities		X	X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983		X	X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983		X	X	
BB	Kraft Pulp Mills		X	X	
BBa	Kraft Pulp Mill Sources for which Construction, Reconstruction or Modification Commenced after May 23, 2013		X		
CC	Glass Manufacturing Plants		X	X	
DD	Grain Elevators		X	X	
EE	Surface Coating of Metal Furniture		X	X	
FF	(Reserved)				
GG	Stationary Gas Turbines		X	X	
HH	Lime Manufacturing Plants		X	X	
KK	Lead-Acid Battery Manufacturing Plants		X	X	
LL	Metallic Mineral Processing Plants		X	X	
MM	Automobile and Light Duty Trucks Surface Coating Operations		X	X	
NN	Phosphate Rock Plants		X	X	
PP	Ammonium Sulfate Manufacture		X	X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing		X	X	
RR	Pressure Sensitive Tape and Label Surface Coating Operations		X	X	
SS	Industrial Surface Coating: Large Appliances		X	X	
TT	Metal Coil Surface Coating		X	X	
UU	Asphalt Processing and Asphalt Roofing Manufacture		X	X	

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing		X	X	
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006		X		
WW	Beverage Can Surface Coating Industry		X	X	
XX	Bulk Gasoline Terminals				
AAA	New Residential Wood Heaters		X	X	
BBB	Rubber Tire Manufacturing Industry		X	X	
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry		X	X	
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing		X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries		X	X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006		X		
HHH	Synthetic Fiber Production Facilities		X	X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes		X		
JJJ	Petroleum Dry Cleaners		X	X	
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants		X	X	
LLL	Onshore Natural Gas Processing: SO_2 Emissions		X		
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations		X	X	
OOO	Nonmetallic Mineral Processing Plants		X	X	
PPP	Wool Fiberglass Insulation Manufacturing Plants		X	X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems		X		
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes		X		
SSS	Magnetic Tape Coating Facilities		X	X	
TTT	Industrial Surface Coating: Surface Coating of Plastic		X	X	

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
	Parts for Business Machines				
UUU	Calciners and Dryers in Mineral Industries		X	X	
VVV	Polymeric Coating of Supporting Substrates Facilities		X	X	
WWW	Municipal Solid Waste Landfills		X		
XXX	Municipal Solid Waste Landfills that Commenced Construction, Reconstruction, or Modification After July 17, 2014		X		
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commended After June 6, 2001		X		
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001		X		
DDDD	Emissions Guidelines and Compliance Times for Commercial and Industrial Solid Waste Incineration Units		X		
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006		X		
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines		X		
JJJJ	Stationary Spark Ignition Internal Combustion Engines		X		
KKKK	Stationary Combustion Turbines		X		
LLLL	New Sewage Sludge Incineration Units		X		
MMMM	Emissions Guidelines and Compliance Times for Existing Sewage Sludge Incineration Units		X		
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution		X		
OOOOa	Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After September 18, 2015		X		
TTTT	Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units		X		
UUUUa	Emission Guidelines for Greenhouse Gas Emissions		X		

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
	From Existing Electric Utility Generating Units				

(ii) [Reserved]

(iii) Delegations for Glenn County Air Pollution Control District, Great Basin Unified Air Pollution Control District, Imperial County Air Pollution Control District, and Kern County Air Pollution Control District are shown in the following table:

Delegation Status for New Source Performance Standards for Glenn County APCD, Great Basin Unified APCD, Imperial County APCD, and Kern County APCD

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
A	General Provisions		X		X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971		X		X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978		X		X
Db	Industrial-Commercial-Institutional Steam Generating Units		X		X
Dc	Small Industrial Steam Generating Units		X		X
E	Incinerators		X		X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994		X		
Eb	Municipal Waste Combustors Constructed After September 20, 1994				
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996				
F	Portland Cement Plants		X		X
G	Nitric Acid Plants		X		X
H	Sulfuric Acid Plants		X		
I	Hot Mix Asphalt Facilities		X		X
J	Petroleum Refineries		X		X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification		X		X

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
	Commenced After June 11, 1973, and Prior to May 19, 1978				
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984		X		X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984		X		X
L	Secondary Lead Smelters		X		X
M	Secondary Brass and Bronze Production Plants		X		X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973		X		X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983		X		X
O	Sewage Treatment Plants		X		X
P	Primary Copper Smelters		X		X
Q	Primary Zinc Smelters		X		X
R	Primary Lead Smelters		X		X
S	Primary Aluminum Reduction Plants		X		X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X		X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X		X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X		X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X		X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities		X		X
Y	Coal Preparation Plants		X		X
Z	Ferroalloy Production Facilities		X		X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983		X		X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983		X		X

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
BB	Kraft pulp Mills		X		X
CC	Glass Manufacturing Plants		X		X
DD	Grain Elevators		X		X
EE	Surface Coating of Metal Furniture		X		X
FF	(Reserved)				
GG	Stationary Gas Turbines		X		X
HH	Lime Manufacturing Plants		X		X
KK	Lead-Acid Battery Manufacturing Plants		X		X
LL	Metallic Mineral Processing Plants		X		X
MM	Automobile and Light Duty Trucks Surface Coating Operations		X		X
NN	Phosphate Rock Plants		X		X
PP	Ammonium Sulfate Manufacture		X		X
QQ	Graphic Arts Industry: Publication Rotogravure Printing		X		X
RR	Pressure Sensitive Tape and Label Surface Coating Operations		X		X
SS	Industrial Surface Coating: Large Appliances		X		X
TT	Metal Coil Surface Coating		X		X
UU	Asphalt Processing and Asphalt Roofing Manufacture		X		X
VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry		X		X
WW	Beverage Can Surface Coating Industry		X		X
XX	Bulk Gasoline Terminals				
AAA	New Residential Wool Heaters		X		X
BBB	Rubber Tire Manufacturing Industry		X		X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry		X		X
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing		X		X
GGG	Equipment Leaks of VOC in Petroleum Refineries		X		X
HHH	Synthetic Fiber Production Facilities		X		X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes		X		X
JJJ	Petroleum Dry Cleaners		X		X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants		X		X

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
LLL	Onshore Natural Gas Processing: SO2 Emissions				X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations		X		X
OOO	Nonmetallic Mineral Processing Plants		X		X
PPP	Wool Fiberglass Insulation Manufacturing Plants		X		X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems		X		X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes				X
SSS	Magnetic Tape Coating Facilities		X		X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines		X	X	
UUU	Calciners and Dryers in Mineral Industries		X		X
VVV	Polymeric Coating of Supporting Substrates Facilities		X		X
WWW	Municipal Solid Waste Landfills				X

(iv) Delegations for Lake County Air Quality Management District, Lassen County Air Pollution Control District, Mariposa County Air Pollution Control District, and Mendocino County Air Pollution Control District are shown in the following table:

Delegation Status for New Source Performance Standards for Lake County Air Quality Management District, Lassen County Air Pollution Control District, Mariposa County Air Pollution Control District, and Mendocino County Air Pollution Control District

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
A	General Provisions	X			X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X			X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X			X
Db	Industrial-Commercial-Institutional Steam Generating Units	X			

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
Dc	Small Industrial Steam Generating Units	X			X
E	Incinerators	X			X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X			X
Eb	Municipal Waste Combustors Constructed After September 20, 1994				
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996				
F	Portland Cement Plants	X			X
G	Nitric Acid Plants	X			X
H	Sulfuric Acid Plants	X			X
I	Hot Mix Asphalt Facilities	X			X
J	Petroleum Refineries	X			X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X			X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X			X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X			X
L	Secondary Lead Smelters	X			X
M	Secondary Brass and Bronze Production Plants	X			X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X			X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X			X
O	Sewage Treatment Plants	X			X
P	Primary Copper Smelters	X			X
Q	Primary Zinc Smelters	X			X
R	Primary Lead Smelters	X			X
S	Primary Aluminum Reduction Plants	X			X

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X			X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X			X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X			X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X			X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X			X
Y	Coal Preparation Plants	X			X
Z	Ferroalloy Production Facilities	X			X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X			X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X			X
BB	Kraft Pulp Mills	X			X
CC	Glass Manufacturing Plants	X			X
DD	Grain Elevators	X			X
EE	Surface Coating of Metal Furniture	X			X
FF	(Reserved)				
GG	Stationary Gas Turbines	X			X
HH	Lime Manufacturing Plants	X			X
KK	Lead-Acid Battery Manufacturing Plants	X			X
LL	Metallic Mineral Processing Plants	X			X
MM	Automobile and Light Duty Trucks Surface Coating Operations	X			X
NN	Phosphate Rock Plants	X			X
PP	Ammonium Sulfate Manufacture	X			X
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X			X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X			X
SS	Industrial Surface Coating: Large Appliances	X			X
TT	Metal Coil Surface Coating	X			X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X			X
VV	Equipment Leaks of VOC in the Synthetic Organic	X			X

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
	Chemicals Manufacturing Industry				
WW	Beverage Can Surface Coating Industry	X			X
XX	Bulk Gasoline Terminals				
AAA	New Residential Wool Heaters	X			X
BBB	Rubber Tire Manufacturing Industry	X			X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X			X
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing	X			X
GGG	Equipment Leaks of VOC in Petroleum Refineries	X			X
HHH	Synthetic Fiber Production Facilities	X			X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X			X
JJJ	Petroleum Dry Cleaners	X			X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X			X
LLL	Onshore Natural Gas Processing: SO2 Emissions	X			X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X			X
OOO	Nonmetallic Mineral Processing Plants	X			X
PPP	Wool Fiberglass Insulation Manufacturing Plants	X			X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X			X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X			
SSS	Magnetic Tape Coating Facilities	X			X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines				
UUU	Calciners and Dryers in Mineral Industries	X			X
VVV	Polymeric Coating of Supporting Substrates Facilities	X			X
WWW	Municipal Solid Waste Landfills	X			

(v) Delegations for Modoc Air Pollution Control District, Mojave Desert Air Quality Management District, Monterey Bay Unified Air Pollution Control District and North Coast Unified Air Quality Management District are shown in the following table:

Table 7 to Paragraph (d)(2)(v)—Delegation Status for New Source Performance Standards for Modoc County APCD, Mojave Desert AQMD, Monterey Bay Unified APCD, and North Coast Unified AQMD

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
A	General Provisions	X	X	X	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X	X	X	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
Dc	Small Industrial-Commercial-Institutional Steam Generating Units		X	X	
E	Incinerators	X	X	X	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994		X		
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994		X		
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996		X		
F	Portland Cement Plants	X	X	X	X
G	Nitric Acid Plants	X	X	X	X
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011				
H	Sulfuric Acid Plant	X	X	X	X
I	Hot Mix Asphalt Facilities	X	X	X	X
J	Petroleum Refineries	X	X	X	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007		X		
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification	X	X	X	X

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
	Commenced After June 11, 1973, and Prior to May 19, 1978				
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X	X	X	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X	X	X	X
L	Secondary Lead Smelters	X	X	X	X
M	Secondary Brass and Bronze Production Plants	X	X	X	X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X	X	X	X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X	X	X	X
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X	X	X	X
Q	Primary Zinc Smelters	X	X	X	X
R	Primary Lead Smelters	X	X	X	X
S	Primary Aluminum Reduction Plants	X	X	X	X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X	X	X	X
Y	Coal Preparation and Processing Plants	X	X	X	X
Z	Ferroalloy Production Facilities	X	X	X	X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	X	X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X	X	X	X

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
BB	Kraft Pulp Mills	X	X	X	X
CC	Glass Manufacturing Plants	X	X	X	X
DD	Grain Elevators	X	X	X	X
EE	Surface Coating of Metal Furniture	X	X	X	X
FF	(Reserved)				
GG	Stationary Gas Turbines	X	X	X	X
HH	Lime Manufacturing Plants	X	X	X	X
KK	Lead-Acid Battery Manufacturing Plants	X	X	X	X
LL	Metallic Mineral Processing Plants	X	X	X	X
MM	Automobile and Light Duty Trucks Surface Coating Operations	X	X	X	X
NN	Phosphate Rock Plants	X	X	X	X
PP	Ammonium Sulfate Manufacture	X	X	X	X
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	X	X
SS	Industrial Surface Coating: Large Appliances	X	X	X	X
TT	Metal Coil Surface Coating	X	X	X	X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	X
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing	X	X	X	X
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006		X		
WW	Beverage Can Surface Coating Industry	X	X	X	X
XX	Bulk Gasoline Terminals				
AAA	New Residential Wood Heaters	X	X	X	X
BBB	Rubber Tire Manufacturing Industry	X	X	X	X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X	X	X	
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	X
GGG	Equipment Leaks of VOC in Petroleum Refineries	X	X	X	X
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006		X		

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
HHH	Synthetic Fiber Production Facilities	X	X	X	X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes		X		
JJJ	Petroleum Dry Cleaners	X	X	X	X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X	X	X	X
LLL	Onshore Natural Gas Processing: SO_2 Emissions	X	X	X	X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X	X	X	
OOO	Nonmetallic Mineral Processing Plants	X	X	X	X
PPP	Wool Fiberglass Insulation Manufacturing Plants	X	X	X	X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X	X	X	X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes		X		
SSS	Magnetic Tape Coating Facilities	X	X	X	X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X	X
UUU	Calciners and Dryers in Mineral Industries		X	X	
VVV	Polymeric Coating of Supporting Substrates Facilities		X	X	X
WWW	Municipal Solid Waste Landfills		X	X	
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commended After June 6, 2001		X		
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001		X		
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006		X		
GGGG	(Reserved)				
HHHH	(Reserved)				

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
IIII	Stationary Compression Ignition Internal Combustion Engines		X	X	
JJJJ	Stationary Spark Ignition Internal Combustion Engines		X	X	
KKKK	Stationary Combustion Turbines		X	X	
LLLL	New Sewage Sludge Incineration Units				
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution				

(vi) Delegations for Northern Sierra Air Quality Management District, Northern Sonoma County Air Pollution Control District, Placer County Air Pollution Control District, and Sacramento Metropolitan Air Quality Management District are shown in the following table:

Delegation Status for New Source Performance Standards for Northern Sierra Air Quality Management District, Northern Sonoma County Air Pollution Control District, Placer County Air Pollution Control District, and Sacramento Metropolitan Air Quality Management District

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	Northern Sonoma County APCD	Placer County APCD	Sacramento Metropolitan AQMD
A	General Provisions		X		X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971		X		X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978		X		X
Db	Industrial-Commercial-Institutional Steam Generating Units				X
Dc	Small Industrial Steam Generating Units				X
E	Incinerators		X		X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994				X
Eb	Municipal Waste Combustors Constructed After September 20, 1994				X
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996				X

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	Northern Sonoma County APCD	Placer County APCD	Sacramento Metropolitan AQMD
F	Portland Cement Plants		X		X
G	Nitric Acid Plants		X		X
H	Sulfuric Acid Plants		X		X
I	Hot Mix Asphalt Facilities		X		X
J	Petroleum Refineries		X		X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978		X		X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984		X		X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984				X
L	Secondary Lead Smelters		X		X
M	Secondary Brass and Bronze Production Plants		X		X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973		X		X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983				X
O	Sewage Treatment Plants		X		X
P	Primary Copper Smelters		X		X
Q	Primary Zinc Smelters		X		X
R	Primary Lead Smelters		X		X
S	Primary Aluminum Reduction Plants		X		X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X		X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X		X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X		X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X		X
X	Phosphate Fertilizer Industry: Granular Triple		X		X

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	Northern Sonoma County APCD	Placer County APCD	Sacramento Metropolitan AQMD
	Superphosphate Storage Facilities				
Y	Coal Preparation Plants		X		X
Z	Ferroalloy Production Facilities		X		X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983		X		X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983				X
BB	Kraft pulp Mills		X		X
CC	Glass Manufacturing Plants		X		X
DD	Grain Elevators		X		X
EE	Surface Coating of Metal Furniture				X
FF	(Reserved)				
GG	Stationary Gas Turbines		X		X
HH	Lime Manufacturing Plants		X		X
KK	Lead-Acid Battery Manufacturing Plants				X
LL	Metallic Mineral Processing Plants				X
MM	Automobile and Light Duty Trucks Surface Coating Operations		X		X
NN	Phosphate Rock Plants				X
PP	Ammonium Sulfate Manufacture		X		X
QQ	Graphic Arts Industry: Publication Rotogravure Printing				X
RR	Pressure Sensitive Tape and Label Surface Coating Operations				X
SS	Industrial Surface Coating: Large Appliances				X
TT	Metal Coil Surface Coating				X
UU	Asphalt Processing and Asphalt Roofing Manufacture				X
VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry				X
WW	Beverage Can Surface Coating Industry				X
XX	Bulk Gasoline Terminals				
AAA	New Residential Wool Heaters				X
BBB	Rubber Tire Manufacturing Industry				X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions				X

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	Northern Sonoma County APCD	Placer County APCD	Sacramento Metropolitan AQMD
	from the Polymer Manufacturing Industry				
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing				X
GGG	Equipment Leaks of VOC in Petroleum Refineries				X
HHH	Synthetic Fiber Production Facilities				X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes				X
JJJ	Petroleum Dry Cleaners				X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants				X
LLL	Onshore Natural Gas Processing: SO2 Emissions				X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations				X
OOO	Nonmetallic Mineral Processing Plants				X
PPP	Wool Fiberglass Insulation Manufacturing Plants				X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems				X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes				X
SSS	Magnetic Tape Coating Facilities				X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines				X
UUU	Calciners and Dryers in Mineral Industries				X
VVV	Polymeric Coating of Supporting Substrates Facilities				X
WWW	Municipal Solid Waste Landfills				X

(vii) Delegations for San Diego County Air Pollution Control District, San Joaquin Valley Unified Air Pollution Control District, San Luis Obispo County Air Pollution Control District, and Santa Barbara County Air Pollution Control District are shown in the following table:

Table 9 to Paragraph (d)(2)(vii)—Delegation Status for New Source Performance Standards for San Diego County APCD, San Joaquin Valley Unified APCD, San Luis Obispo County APCD, and Santa Barbara County APCD

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
A	General Provisions	X	X	X	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X	X	X	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
E	Incinerators	X	X	X	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X	X	X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994	X	X		X
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	X			X
F	Portland Cement Plants	X	X	X	
G	Nitric Acid Plants	X	X	X	
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011				
H	Sulfuric Acid Plant	X	X	X	
I	Hot Mix Asphalt Facilities	X	X	X	X
J	Petroleum Refineries	X	X	X	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007				X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X	X	X	X
Ka	Storage Vessels for Petroleum Liquids for Which	X	X	X	X

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
	Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984				
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X	X	X	X
L	Secondary Lead Smelters	X	X	X	X
M	Secondary Brass and Bronze Production Plants	X	X	X	X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X	X	X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X	X	X	
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X	X	X	
Q	Primary Zinc Smelters	X	X	X	
R	Primary Lead Smelters	X	X	X	
S	Primary Aluminum Reduction Plants	X	X	X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X	X	X	
Y	Coal Preparation and Processing Plants	X	X	X	
Z	Ferroalloy Production Facilities	X	X	X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X	X	X	
BB	Kraft Pulp Mills	X	X	X	
CC	Glass Manufacturing Plants	X	X	X	X

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
DD	Grain Elevators	X	X	X	X
EE	Surface Coating of Metal Furniture	X	X	X	
FF	(Reserved)				
GG	Stationary Gas Turbines	X	X	X	X
HH	Lime Manufacturing Plants	X	X	X	
KK	Lead-Acid Battery Manufacturing Plants	X	X	X	
LL	Metallic Mineral Processing Plants	X	X	X	
MM	Automobile and Light Duty Trucks Surface Coating Operations	X	X	X	
NN	Phosphate Rock Plants	X	X	X	
PP	Ammonium Sulfate Manufacture	X	X	X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X	X	X	
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	X	
SS	Industrial Surface Coating: Large Appliances	X	X	X	
TT	Metal Coil Surface Coating	X	X	X	
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing	X	X	X	
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006				X
WW	Beverage Can Surface Coating Industry	X	X	X	
XX	Bulk Gasoline Terminals				
AAA	New Residential Wood Heaters	X	X	X	X
BBB	Rubber Tire Manufacturing Industry	X	X	X	
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X	X		
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries	X	X	X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006				X
HHH	Synthetic Fiber Production Facilities	X	X	X	

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X	X		
JJJ	Petroleum Dry Cleaners	X	X	X	
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X	X	X	
LLL	Onshore Natural Gas Processing: SO_2 Emissions	X	X	X	
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X	X		
OOO	Nonmetallic Mineral Processing Plants	X	X	X	X
PPP	Wool Fiberglass Insulation Manufacturing Plants	X	X	X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X	X	X	
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X	X	X	
SSS	Magnetic Tape Coating Facilities	X	X	X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X	
UUU	Calciners and Dryers in Mineral Industries	X	X	X	X
VVV	Polymeric Coating of Supporting Substrates Facilities	X	X	X	X
WWW	Municipal Solid Waste Landfills	X	X	X	X
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commended After June 6, 2001	X			X
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X			X
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006	X			X
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion	X			X

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
	Engines				
JJJJ	Stationary Spark Ignition Internal Combustion Engines	X			X
KKKK	Stationary Combustion Turbines	X			X
LLLL	New Sewage Sludge Incineration Units				
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution				
QQQQ	Standards of Performance for New Residential Hydronic Heaters and Forced-Air Furnaces	X			
TTTT	Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units	X			

(viii) Delegations for Shasta County Air Quality Management District, Siskiyou County Air Pollution Control District, South Coast Air Quality Management District, and Tehama County Air Pollution Control District are shown in the following table:

Delegation Status for New Source Performance Standards for Shasta County AQMD, Siskiyou County APCD, South Coast AQMD, and Tehama County APCD

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
A	General Provisions	X	X	X	
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X		X	
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978			X	
Db	Industrial-Commercial-Institutional Steam Generating Units			X	
Dc	Small Industrial-Commercial-Institutional Steam Generating Units			X	
E	Incinerators	X		X	
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994			X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994			X	

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996			X	
F	Portland Cement Plants	X		X	
G	Nitric Acid Plants	X		X	
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011				
H	Sulfuric Acid Plant	X		X	
I	Hot Mix Asphalt Facilities	X		X	
J	Petroleum Refineries	X		X	
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007			X	
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X		X	
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984			X	
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984			X	
L	Secondary Lead Smelters	X		X	
M	Secondary Brass and Bronze Production Plants	X		X	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X		X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983			X	
O	Sewage Treatment Plants	X		X	
P	Primary Copper Smelters	X		X	
Q	Primary Zinc Smelters	X		X	
R	Primary Lead Smelters	X		X	
S	Primary Aluminum Reduction Plants	X		X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X		X	
U	Phosphate Fertilizer Industry: Superphosphoric Acid	X		X	

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
	Plants				
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X		X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X		X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X		X	
Y	Coal Preparation and Processing Plants	X		X	
Z	Ferroalloy Production Facilities	X		X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X		X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983			X	
BB	Kraft Pulp Mills	X		X	
CC	Glass Manufacturing Plants			X	
DD	Grain Elevators	X		X	
EE	Surface Coating of Metal Furniture			X	
FF	(Reserved)				
GG	Stationary Gas Turbines			X	
HH	Lime Manufacturing Plants	X		X	
KK	Lead-Acid Battery Manufacturing Plants			X	
LL	Metallic Mineral Processing Plants			X	
MM	Automobile and Light Duty Trucks Surface Coating Operations			X	
NN	Phosphate Rock Plants			X	
PP	Ammonium Sulfate Manufacture			X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing			X	
RR	Pressure Sensitive Tape and Label Surface Coating Operations			X	
SS	Industrial Surface Coating: Large Appliances			X	
TT	Metal Coil Surface Coating			X	
UU	Asphalt Processing and Asphalt Roofing Manufacture			X	
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing			X	
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006			X	

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
WW	Beverage Can Surface Coating Industry			X	
XX	Bulk Gasoline Terminals				
AAA	New Residential Wood Heaters		X	X	
BBB	Rubber Tire Manufacturing Industry		X	X	
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry			X	
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing			X	
GGG	Equipment Leaks of VOC in Petroleum Refineries			X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006			X	
HHH	Synthetic Fiber Production Facilities			X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes			X	
JJJ	Petroleum Dry Cleaners			X	
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants			X	
LLL	Onshore Natural Gas Processing: SO_2 Emissions			X	
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations			X	
OOO	Nonmetallic Mineral Processing Plants			X	
PPP	Wool Fiberglass Insulation Manufacturing Plants			X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems		X	X	
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes			X	
SSS	Magnetic Tape Coating Facilities		X	X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines		X	X	
UUU	Calciners and Dryers in Mineral Industries			X	
VVV	Polymeric Coating of Supporting Substrates Facilities			X	
WWW	Municipal Solid Waste Landfills			X	
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or	X	X	X	

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
	for Which Modification or Reconstruction is Commended After June 6, 2001				
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001			X	
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006			X	
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines			X	
JJJJ	Stationary Spark Ignition Internal Combustion Engines			X	
KKKK	Stationary Combustion Turbines			X	
LLLL	New Sewage Sludge Incineration Units				
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution				

(ix) Delegations for Tuolumne County Air Pollution Control District, Ventura County Air Pollution Control District, and Yolo-Solano Air Quality Management District are shown in the following table:

Table 11 to Paragraph (d)(2)(ix)—Delegation Status for New Source Performance Standards for Tuolumne County APCD, Ventura County APCD, and Yolo-Solano AQMD

	Subpart	Air pollution control agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
A	General Provisions		X	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971		X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978		X	
Db	Industrial-Commercial-Institutional Steam Generating Units		X	X
Dc	Small Industrial-Commercial-Institutional Steam Generating Units		X	

	Subpart	Air pollution control agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
E	Incinerators		X	
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994		X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994			
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996			
F	Portland Cement Plants		X	
G	Nitric Acid Plants		X	
H	Sulfuric Acid Plant		X	
I	Hot Mix Asphalt Facilities		X	X
J	Petroleum Refineries		X	X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978		X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984		X	
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984		X	
L	Secondary Lead Smelters		X	
M	Secondary Brass and Bronze Production Plants		X	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973		X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983		X	
O	Sewage Treatment Plants		X	
P	Primary Copper Smelters		X	
Q	Primary Zinc Smelters		X	
R	Primary Lead Smelters		X	
S	Primary Aluminum Reduction Plants		X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate		X	

	Subpart	Air pollution control agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
	Storage Facilities			
Y	Coal Preparation and Processing Plants		X	
Z	Ferroalloy Production Facilities		X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983		X	X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983		X	
BB	Kraft Pulp Mills		X	
CC	Glass Manufacturing Plants		X	
DD	Grain Elevators		X	
EE	Surface Coating of Metal Furniture		X	
FF	(Reserved)			
GG	Stationary Gas Turbines		X	
HH	Lime Manufacturing Plants		X	
KK	Lead-Acid Battery Manufacturing Plants		X	
LL	Metallic Mineral Processing Plants		X	
MM	Automobile and Light Duty Trucks Surface Coating Operations		X	
NN	Phosphate Rock Plants		X	
PP	Ammonium Sulfate Manufacture		X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing		X	
RR	Pressure Sensitive Tape and Label Surface Coating Operations		X	
SS	Industrial Surface Coating: Large Appliances		X	
TT	Metal Coil Surface Coating		X	
UU	Asphalt Processing and Asphalt Roofing Manufacture		X	
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing		X	
WW	Beverage Can Surface Coating Industry		X	
XX	Bulk Gasoline Terminals			
AAA	New Residential Wood Heaters		X	
BBB	Rubber Tire Manufacturing Industry		X	
CCC	(Reserved)			
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry		X	
EEE	(Reserved)			
FFF	Flexible Vinyl and Urethane Coating and Printing		X	
GGG	Equipment Leaks of VOC in Petroleum Refineries		X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced			

	Subpart	Air pollution control agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
	After November 7, 2006			
HHH	Synthetic Fiber Production Facilities		X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes		X	
JJJ	Petroleum Dry Cleaners		X	
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants		X	
LLL	Onshore Natural Gas Processing: SO_2 Emissions		X	
MMM	(Reserved)			
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations		X	
OOO	Nonmetallic Mineral Processing Plants		X	X
PPP	Wool Fiberglass Insulation Manufacturing Plants		X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems		X	
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes		X	
SSS	Magnetic Tape Coating Facilities		X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines		X	
UUU	Calciners and Dryers in Mineral Industries		X	
VVV	Polymeric Coating of Supporting Substrates Facilities		X	
WWW	Municipal Solid Waste Landfills	X	X	

(3) ***Hawaii.*** The following table identifies delegations for Hawaii:

Delegation Status for New Source Performance Standards for Hawaii:

Delegation Status for New Source Performance Standards for Hawaii

	Subpart	Hawaii
A	General Provisions	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X
Dc	Small Industrial Steam Generating Units	X
E	Incinerators	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X

	Subpart	Hawaii
Eb	Municipal Waste Combustors Constructed After September 20, 1994	X
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	X
F	Portland Cement Plants	X
G	Nitric Acid Plants	
H	Sulfuric Acid Plants	
I	Hot Mix Asphalt Facilities	X
J	Petroleum Refineries	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007	
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X
L	Secondary Lead Smelters	
M	Secondary Brass and Bronze Production Plants	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	
O	Sewage Treatment Plants	X
P	Primary Copper Smelters	
Q	Primary Zinc Smelters	
R	Primary Lead Smelters	
S	Primary Aluminum Reduction Plants	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	
Y	Coal Preparation Plants	X
Z	Ferroalloy Production Facilities	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X
BB	Kraft pulp Mills	
CC	Glass Manufacturing Plants	
DD	Grain Elevators	
EE	Surface Coating of Metal Furniture	

	Subpart	Hawaii
FF	(Reserved)	
GG	Stationary Gas Turbines	X
HH	Lime Manufacturing Plants	
KK	Lead-Acid Battery Manufacturing Plants	
LL	Metallic Mineral Processing Plants	
MM	Automobile and Light Duty Trucks Surface Coating Operations	
NN	Phosphate Rock Plants	
PP	Ammonium Sulfate Manufacture	
QQ	Graphic Arts Industry: Publication Rotogravure Printing	
RR	Pressure Sensitive Tape and Label Surface Coating Operations	
SS	Industrial Surface Coating: Large Appliances	
TT	Metal Coil Surface Coating	
UU	Asphalt Processing and Asphalt Roofing Manufacture	
VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry	X
VVa	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	
WW	Beverage Can Surface Coating Industry	X
XX	Bulk Gasoline Terminals	X
AAA	New Residential Wool Heaters	
BBB	Rubber Tire Manufacturing Industry	
CCC	(Reserved)	
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	
EEE	(Reserved)	
FFF	Flexible Vinyl and Urethane Coating and Printing	
GGG	Equipment Leaks of VOC in Petroleum Refineries	X
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	
HHH	Synthetic Fiber Production Facilities	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	
JJJ	Petroleum Dry Cleaners	X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	
LLL	Onshore Natural Gas Processing: SO2 Emissions	
MMM	(Reserved)	
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X
OOO	Nonmetallic Mineral Processing Plants	X
PPP	Wool Fiberglass Insulation Manufacturing Plants	
QQQ	VOC Emissions From Petroleum Refinery Wastewater	X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing	

	Subpart	Hawaii
	Industry (SOCMI) Reactor Processes	
SSS	Magnetic Tape Coating Facilities	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	
UUU	Calciners and Dryers in Mineral Industries	X
VVV	Polymeric Coating of Supporting Substrates Facilities	X
WWW	Municipal Solid Waste Landfills	X
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001	X
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006	
GGGG	(Reserved)	
IIII	Stationary Compression Ignition Internal Combustion Engines	
JJJJ	Stationary Spark Ignition Internal Combustion Engines	
KKKK	Stationary Combustion Turbines	

(4) ***Nevada.*** The following table identifies delegations for Nevada:

Table 12 to Paragraph (d)(4)—Delegation Status for New Source Performance Standards for Nevada

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
A	General Provisions	X	X	X
Cf	Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills	X		
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X	X	
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	X	X	
E	Incinerators	X	X	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X	X	
Eb	Large Municipal Waste Combustors Constructed After September 20,	X	X	

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
	1994			
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	X	X	
F	Portland Cement Plants	X	X	X
G	Nitric Acid Plants	X	X	
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011	X		
H	Sulfuric Acid Plant	X	X	
I	Hot Mix Asphalt Facilities	X	X	X
J	Petroleum Refineries	X	X	
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007	X		
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X	X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X	X	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X	X	
L	Secondary Lead Smelters	X	X	X
M	Secondary Brass and Bronze Production Plants	X	X	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X	X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X	X	
O	Sewage Treatment Plants	X	X	X
P	Primary Copper Smelters	X	X	X
Q	Primary Zinc Smelters	X	X	X
R	Primary Lead Smelters	X	X	X
S	Primary Aluminum Reduction Plants	X	X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities		X	
Y	Coal Preparation and Processing Plants	X	X	X

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
Z	Ferroalloy Production Facilities	X	X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X	X	
BB	Kraft Pulp Mills		X	
CC	Glass Manufacturing Plants	X	X	
DD	Grain Elevators	X	X	X
EE	Surface Coating of Metal Furniture	X	X	X
FF	(Reserved)			
GG	Stationary Gas Turbines	X	X	X
HH	Lime Manufacturing Plants	X	X	X
KK	Lead-Acid Battery Manufacturing Plants	X	X	X
LL	Metallic Mineral Processing Plants	X	X	X
MM	Automobile and Light Duty Trucks Surface Coating Operations	X	X	X
NN	Phosphate Rock Plants	X	X	X
PP	Ammonium Sulfate Manufacture	X	X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	
SS	Industrial Surface Coating: Large Appliances	X	X	X
TT	Metal Coil Surface Coating	X	X	X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing	X	X	X
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006	X	X	
WW	Beverage Can Surface Coating Industry	X	X	
XX	Bulk Gasoline Terminals	X	X	
AAA	New Residential Wood Heaters		X	
BBB	Rubber Tire Manufacturing Industry	X	X	
CCC	(Reserved)			
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X	X	
EEE	(Reserved)			
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries	X	X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After	X	X	

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
	November 7, 2006			
HHH	Synthetic Fiber Production Facilities	X	X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X	X	
JJJ	Petroleum Dry Cleaners	X	X	X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X	X	
LLL	Onshore Natural Gas Processing: SO_2 Emissions	X	X	
MMM	(Reserved)			
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X	X	
OOO	Nonmetallic Mineral Processing Plants	X	X	
PPP	Wool Fiberglass Insulation Manufacturing Plants	X	X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X	X	
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X	X	
SSS	Magnetic Tape Coating Facilities	X	X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X
UUU	Calciners and Dryers in Mineral Industries	X	X	X
VVV	Polymeric Coating of Supporting Substrates Facilities	X	X	X
WWW	Municipal Solid Waste Landfills	X	X	X
XXX	Municipal Solid Waste Landfills that Commenced Construction, Reconstruction, or Modification after July 17, 2014	X		
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commended After June 6, 2001	X	X	X
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X	X	X
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006	X	X	X
GGGG	(Reserved)			
HHHH	(Reserved)			
IIII	Stationary Compression Ignition Internal Combustion Engines	X	X	X
JJJJ	Stationary Spark Ignition Internal Combustion Engines	X	X	X
KKKK	Stationary Combustion Turbines	X	X	X

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
LLLL	New Sewage Sludge Incineration Units		X	
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution	X		

(5) ***Guam.*** The following table identifies delegations as of June 15, 2001:

Delegation Status for New Source Performance Standards for Guam

	Subpart	Guam
A	General Provisions	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	
Db	Industrial-Commercial-Institutional Steam Generating Units	
Dc	Small Industrial Steam Generating Units	
E	Incinerators	
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	
Eb	Municipal Waste Combustors Constructed After September 20, 1994	
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	
F	Portland Cement Plants	X
G	Nitric Acid Plants	
H	Sulfuric Acid Plants	
I	Hot Mix Asphalt Facilities	X
J	Petroleum Refineries	X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X

(e) The following lists the specific part 60 standards that have been delegated unchanged to the air pollution control agencies in Region 6.

(1) ***New Mexico.*** The New Mexico Environment Department has been delegated all part 60 standards promulgated by the EPA, except subpart AAA—Standards of Performance for New Residential Wood Heaters; and subpart QQQQ—Standards of Performance for New Residential Hydronic Heaters and Forced-Air Furnaces, as amended in the FEDERAL REGISTER through January 15, 2017.

(2) ***Louisiana.*** The Louisiana Department of Environmental Quality has been delegated all part 60 standards promulgated by EPA, except subpart AAA—Standards of Performance for New Residential Wood Heaters, as amended in the FEDERAL REGISTER through July 1, 2013.

Delegation Status for Part 60 Standards—State of Louisiana

[Excluding Indian Country]

Subpart	Source category	LDEQ[1]
A	General Provisions	Yes
Ce	Emission Guidelines and Compliance Times for Hospital/Medical/Infectious Waste Incinerators	Yes
D	Fossil Fueled Steam Generators (>250 MM BTU/hr)	Yes
Da	Electric Utility Steam Generating Units (>250 MM BTU/hr)	Yes
Db	Industrial-Commercial-Institutional Steam Generating Units (100 to 250 MM BTU/hr)	Yes
Dc	Industrial-Commercial-Institutional Small Steam Generating Units (10 to 100 MM BTU/hr)	Yes
E	Incinerators (>50 tons per day)	Yes
Ea	Municipal Waste Combustors	Yes
Eb	Large Municipal Waste Combustors	Yes
Ec	Hospital/Medical/Infectious Waste Incinerators	Yes
F	Portland Cement Plants	Yes
G	Nitric Acid Plants	Yes
Ga	Nitric Acid Plants (after October 14, 2011)	Yes
H	Sulfuric Acid Plants	Yes
I	Hot Mix Asphalt Facilities	Yes
J	Petroleum Refineries	Yes
Ja	Petroleum Refineries (After May 14, 2007)	Yes
K	Storage Vessels for Petroleum Liquids (After 6/11/73 & Before 5/19/78)	Yes
Ka	Storage Vessels for Petroleum Liquids (After 6/11/73 & Before 5/19/78)	Yes
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Stg/Vessels) After 7/23/84	Yes
L	Secondary Lead Smelters Yes	Yes
M	Secondary Brass and Bronze Production Plants	Yes
N	Primary Emissions from Basic Oxygen Process Furnaces (Construction Commenced After June 11, 1973)	Yes
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities Construction is Commenced After January 20, 1983	Yes
O	Sewage Treatment Plants	Yes
P	Primary Copper Smelters	Yes
Q	Primary Zinc Smelters	Yes
R	Primary Lead Smelters	Yes
S	Primary Aluminum Reduction Plants	Yes
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Plants	Yes
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	Yes
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	Yes
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	Yes
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	Yes

Subpart	Source category	LDEQ[1]
Y	Coal Preparation Plants	Yes
Z	Ferroalloy Production Facilities	Yes
AA	Steel Plants: Electric Arc Furnaces After 10/21/74 & On or Before 8/17/83	Yes
AAa	Steel Plants: Electric Arc Furnaces & Argon-Oxygen Decarburization Vessels After 8/07/83	Yes
BB	Kraft Pulp Mills	Yes
CC	Glass Manufacturing Plants	Yes
DD	Grain Elevators	Yes
EE	Surface Coating of Metal Furniture	Yes
GG	Stationary Gas Turbines	Yes
HH	Lime Manufacturing Plants	Yes
KK	Lead-Acid Battery Manufacturing Plants	Yes
LL	Metallic Mineral Processing Plants	Yes
MM	Automobile & Light Duty Truck Surface Coating Operations	Yes
NN	Phosphate Manufacturing Plants	Yes
PP	Ammonium Sulfate Manufacture	Yes
QQ	Graphic Arts Industry: Publication Rotogravure Printing	Yes
RR	Pressure Sensitive Tape and Label Surface Coating Operations	Yes
SS	Industrial Surface Coating: Large Appliances	Yes
TT	Metal Coil Surface Coating	Yes
UU	Asphalt Processing and Asphalt Roofing Manufacture	Yes
VV	VOC Equipment Leaks in the SOCMI Industry	Yes
VVa	VOC Equipment Leaks in the SOCMI Industry (After November 7, 2006)	Yes
XX	Bulk Gasoline Terminals	Yes
AAA	New Residential Wood Heaters	No
BBB	Rubber Tire Manufacturing Industry	Yes
DDD	Volatile Organic Compound (VOC) Emissions from the Polymer Manufacturing Industry	Yes
FFF	Flexible Vinyl and Urethane Coating and Printing	Yes
GGG	VOC Equipment Leaks in Petroleum Refineries	Yes
HHH	Synthetic Fiber Production	Yes
III	VOC Emissions from the SOCMI Air Oxidation Unit Processes	Yes
JJJ	Petroleum Dry Cleaners	Yes
KKK	VOC Equipment Leaks From Onshore Natural Gas Processing Plants	Yes
LLL	Onshore Natural Gas Processing: SO_2 Emissions	Yes
NNN	VOC Emissions from SOCMI Distillation Operations	Yes
OOO	Nonmetallic Mineral Processing Plants	Yes
PPP	Wool Fiberglass Insulation Manufacturing Plants	Yes
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	Yes
RRR	VOC Emissions from SOCMI Reactor Processes	Yes
SSS	Magnetic Tape Coating Operations	Yes

Subpart	Source category	LDEQ[1]
TTT	Industrial Surface Coating: Plastic Parts for Business Machines	Yes
UUU	Calciners and Dryers in Mineral Industries	Yes
VVV	Polymeric Coating of Supporting Substrates Facilities	Yes
WWW	Municipal Solid Waste Landfills	Yes
AAAA	Small Municipal Waste Combustion Units (Construction is Commenced After 8/30/99 or Modification/Reconstruction is Commenced After 6/06/2001)	Yes
CCCC	Commercial & Industrial Solid Waste Incineration Units (Construction is Commenced After 11/30/1999 or Modification/Reconstruction is Commenced on or After 6/01/2001)	Yes
DDDD	Emission Guidelines & Compliance Times for Commercial & Industrial Solid Waste Incineration Units (Commenced Construction On or Before 11/30/1999)	Yes
EEEE	Other Solid Waste Incineration Units (Constructed after 12/09/2004 or Modification/Reconstruction is commenced on or after 06/16/2004)	Yes
IIII	Stationary Compression Ignition Internal Combustion Engines	Yes
JJJJ	Stationary Spark Ignition Internal Combustion Engines	Yes
KKKK	Stationary Combustion Turbines (Construction Commenced After 02/18/2005)	Yes
LLLL	New Sewage Sludge Incineration Units	Yes
MMMM	Emission Guidelines and Compliance Times for Existing Sewage Sludge Incineration Units	Yes
OOOO	Crude Oil and Natural Gas Production, Transmission and Distribution	Yes

[1] The Louisiana Department of Environmental Quality (LDEQ) has been delegated all Part 60 standards promulgated by EPA, except subpart AAA—Standards of Performance for New Residential Wood Heaters—as amended in the FEDERAL REGISTER through July 1, 2013.

(3) ***Albuquerque-Bernalillo County Air Quality Control Board.*** The Albuquerque-Bernalillo County Air Quality Control Board has been delegated all part 60 standards promulgated by the EPA, except subpart AAA of this part and subpart QQQQ of this part as amended through January 23, 2017.

[40 FR 18169, Apr. 25, 1975]

Editorial Note: For FEDERAL REGISTER citations affecting § 60.4, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at *www.govinfo.gov*.

§ 60.5 Determination of construction or modification.

(a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.

(b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

[40 FR 58418, Dec. 16, 1975]

§ 60.6 Review of plans.

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.

(b)

(1) A separate request shall be submitted for each construction or modification project.

(2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any equipment to be used for measurement or control of emissions.

(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall

(1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or

(2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 9314, Mar. 8, 1974]

§ 60.7 Notification and record keeping.

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

(1) A notification of the date construction (or reconstruction as defined under § 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

(2) [Reserved]

(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in § 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with § 60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

(6) A notification of the anticipated date for conducting the opacity observations required by § 60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7) A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by § 60.8 in lieu of Method 9 observation data as allowed by § 60.11(e)(5) of this part. This notification shall be postmarked not less than 30 days prior to the date of the performance test.

(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with § 60.13(h), 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.

(2) 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.

(3) The date and time 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.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(d) The summary report form shall contain the information and be in the format shown in figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in § 60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in § 60.7(c) shall both be submitted.

Figure 1—Summary Report—Gaseous and Opacity Excess Emission and Monitoring System Performance

Pollutant (Circle One—SO_2/NO_X/TRS/H_2S/CO/Opacity)

Reporting period dates: From ____________ to ____________

Company:

Emission Limitation ____________________

Address:

Monitor Manufacturer and Model No. ________________

Date of Latest CMS Certification or Audit ________________

Process Unit(s) Description:

Total source operating time in reporting period[1] ______________

Emission data summary[1]		CMS performance summary[1]	
1. Duration of excess emissions in reporting period due to:		1. CMS downtime in reporting period due to:	
a. Startup/shutdown		a. Monitor equipment malfunctions	
b. Control equipment problems		b. Non-Monitor equipment malfunctions	
c. Process problems		c. Quality assurance calibration	
d. Other known causes		d. Other known causes	
e. Unknown causes		e. Unknown causes	
2. Total duration of excess emission		2. Total CMS Downtime	
3. Total duration of excess emissions × (100) [Total source operating time]	%[2]	3. [Total CMS Downtime] × (100) [Total source operating time]	%[2]

[1] For opacity, record all times in minutes. For gases, record all times in hours.

[2] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in § 60.7(c) shall be submitted.

On a separate page, describe any changes since last quarter in CMS, process or controls. I certify that the information contained in this report is true, accurate, and complete.

____

Name

Signature

Title

Date

(e)

(1) Notwithstanding the frequency of reporting requirements specified in paragraph (c) of this section, an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the applicable standard; and

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in paragraph (e)(2) of this section.

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in paragraphs (e)(1) and (e)(2) of this section.

(f) Any owner or operator subject to the provisions of this part shall 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 part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:

(1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

(2) This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.

(3) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph (f) of this section, if the Administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.

(g) If notification substantially similar to that in paragraph (a) of this section is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section.

(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

[36 FR 24877, Dec. 28, 1971, as amended at 40 FR 46254, Oct. 6, 1975; 40 FR 58418, Dec. 16, 1975; 45 FR 5617, Jan. 23, 1980; 48 FR 48335, Oct. 18, 1983; 50 FR 53113, Dec. 27, 1985; 52 FR 9781, Mar. 26, 1987; 55 FR 51382, Dec. 13, 1990; 59 FR 12428, Mar. 16, 1994; 59 FR 47265, Sep. 15, 1994; 64 FR 7463, Feb. 12, 1999]

§ 60.8 Performance tests.

(a) Except as specified in paragraphs (a)(1),(a)(2), (a)(3), and (a)(4) of this section, within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by this part, and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(1) If a force majeure is about to occur, occurs, or has occurred for which the affected owner or operator intends to assert a claim of force majeure, the owner or operator shall notify the Administrator, in writing as soon as practicable following the date the owner or operator first knew, or through due diligence should have known that the event may cause or caused a delay in testing beyond the regulatory deadline, but the notification must occur before the performance test deadline unless the initial force majeure or a subsequent force majeure event delays the notice, and in such cases, the notification shall occur as soon as practicable.

(2) The owner or operator shall provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in testing beyond the regulatory deadline to the force majeure; describe the measures taken or to be taken to minimize the delay; and identify a date by which the owner or operator proposes to conduct the performance test. The performance test shall be conducted as soon as practicable after the force majeure occurs.

(3) The decision as to whether or not to grant an extension to the performance test deadline is solely within the discretion of the Administrator. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an extension as soon as practicable.

(4) Until an extension of the performance test deadline has been approved by the Administrator under paragraphs (a)(1), (2), and (3) of this section, the owner or operator of the affected facility remains strictly subject to the requirements of this part.

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator

(1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology,

(2) approves the use of an equivalent method,

(3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance,

(4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or

(5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the Administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes

(i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and

(ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).

(4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method.

(1) Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

(2) Contents of report (electronic or paper submitted copy). Unless otherwise specified in a relevant standard or test method, or as otherwise approved by the Administrator in writing, the report for a performance test shall include the elements identified in paragraphs (f)(2)(i) through (vi) of this section.

(i) General identification information for the facility including a mailing address, the physical address, the owner or operator or responsible official (where applicable) and his/her email address, and the appropriate Federal Registry System (FRS) number for the facility.

(ii) Purpose of the test including the applicable regulation(s) requiring the test, the pollutant(s) and other parameters being measured, the applicable emission standard and any process parameter component, and a brief process description.

(iii) Description of the emission unit tested including fuel burned, control devices, and vent characteristics; the appropriate source classification code (SCC); the permitted maximum process rate (where applicable); and the sampling location.

(iv) Description of sampling and analysis procedures used and any modifications to standard procedures, quality assurance procedures and results, record of process operating conditions that demonstrate the applicable test conditions are met, and values for any operating parameters for which limits were being set during the test.

(v) Where a test method requires you record or report, the following shall be included: Record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, chain-of-custody documentation, and example calculations for reported results.

(vi) Identification of the company conducting the performance test including the primary office address, telephone number, and the contact for this test program including his/her email address.

(g) The performance testing shall include a test method performance audit (PA) during the performance test. The PAs consist of blind audit samples supplied by an accredited audit sample provider and analyzed during the performance test in order to provide a measure of test data bias. Gaseous audit samples are designed to audit the performance of the sampling system as well as the analytical system and must be collected by the sampling system during the compliance test just as the compliance samples are collected. If a liquid or solid audit sample is designed to audit the sampling system, it must also be collected by the sampling system during the compliance test. If multiple sampling systems or sampling trains are used during the compliance test for any of the test methods, the tester is only required to use one of the sampling systems per method to collect the audit sample. The audit sample must be analyzed by the same analyst using the same analytical reagents and analytical system and at the same time as the compliance samples. Retests are required when there is a failure to produce acceptable results for an audit sample. However, if the audit results do not affect the compliance or noncompliance status of the affected facility, the compliance authority may waive the reanalysis requirement, further audits, or retests and accept the results of the compliance test. Acceptance of the test results shall constitute a waiver of the reanalysis requirement, further audits, or retests. The compliance authority may also use the audit sample failure and the compliance test results as evidence to determine the compliance or noncompliance status of the affected facility. A blind audit sample is a sample whose value is known only to the sample provider and is not revealed to the tested facility until after they report the measured value of the audit sample. For pollutants that exist in the gas phase at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in air or nitrogen that can be introduced into the sampling system of the test method at or near the same entry point as a sample from the emission source. If no gas phase audit samples are available, an acceptable alternative is a sample of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. For samples that exist only in a liquid or solid form at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. An accredited audit sample provider (AASP) is an organization that has been accredited to prepare audit samples by an independent, third party accrediting body.

(1) The source owner, operator, or representative of the tested facility shall obtain an audit sample, if commercially available, from an AASP for each test method used for regulatory compliance purposes. No audit samples are required for the following test methods: Methods 3A and 3C of appendix A-3 of part 60, Methods 6C, 7E, 9, and 10 of appendix A-4 of part 60, Methods 18 and 19 of appendix A-6 of part 60, Methods 20, 22, and 25A of appendix A-7 of part 60, Methods 30A and 30B of appendix A-8 of part 60, and Methods 303, 318, 320, and 321 of appendix A of part 63 of this chapter. If multiple sources at a single facility are tested during a compliance test event, only one audit sample is required for each method used during a compliance test. The compliance authority responsible for the compliance test may waive the requirement to include an audit sample if they believe that an audit sample is not necessary. "Commercially available" means that two or more independent AASPs have blind audit samples available for purchase. If the source owner, operator, or

representative cannot find an audit sample for a specific method, the owner, operator, or representative shall consult the EPA Web site at the following URL, *www.epa.gov/ttn/emc,* to confirm whether there is a source that can supply an audit sample for that method. If the EPA Web site does not list an available audit sample at least 60 days prior to the beginning of the compliance test, the source owner, operator, or representative shall not be required to include an audit sample as part of the quality assurance program for the compliance test. When ordering an audit sample, the source owner, operator, or representative shall give the sample provider an estimate for the concentration of each pollutant that is emitted by the source or the estimated concentration of each pollutant based on the permitted level and the name, address, and phone number of the compliance authority. The source owner, operator, or representative shall report the results for the audit sample along with a summary of the emission test results for the audited pollutant to the compliance authority and shall report the results of the audit sample to the AASP. The source owner, operator, or representative shall make both reports at the same time and in the same manner or shall report to the compliance authority first and then report to the AASP. If the method being audited is a method that allows the samples to be analyzed in the field and the tester plans to analyze the samples in the field, the tester may analyze the audit samples prior to collecting the emission samples provided a representative of the compliance authority is present at the testing site. The tester may request and the compliance authority may grant a waiver to the requirement that a representative of the compliance authority must be present at the testing site during the field analysis of an audit sample. The source owner, operator, or representative may report the results of the audit sample to the compliance authority and report the results of the audit sample to the AASP prior to collecting any emission samples. The test protocol and final test report shall document whether an audit sample was ordered and utilized and the pass/fail results as applicable.

(2) An AASP shall have and shall prepare, analyze, and report the true value of audit samples in accordance with a written technical criteria document that describes how audit samples will be prepared and distributed in a manner that will ensure the integrity of the audit sample program. An acceptable technical criteria document shall contain standard operating procedures for all of the following operations:

(i) Preparing the sample;

(ii) Confirming the true concentration of the sample;

(iii) Defining the acceptance limits for the results from a well qualified tester. This procedure must use well established statistical methods to analyze historical results from well qualified testers. The acceptance limits shall be set so that there is 95 percent confidence that 90 percent of well qualified labs will produce future results that are within the acceptance limit range.

(iv) Providing the opportunity for the compliance authority to comment on the selected concentration level for an audit sample;

(v) Distributing the sample to the user in a manner that guarantees that the true value of the sample is unknown to the user;

(vi) Recording the measured concentration reported by the user and determining if the measured value is within acceptable limits;

(vii) The AASP shall report the results from each audit sample in a timely manner to the compliance authority and then to the source owner, operator, or representative. The AASP shall make both reports at the same time and in the same manner or shall report to the compliance authority first and then report to the source owner, operator, or representative. The results shall include the name of the facility tested, the date on which the compliance test was conducted, the name of the company performing the sample collection, the name of the company that analyzed the compliance samples including the audit sample, the measured result for the audit sample, and whether the testing company passed or failed the audit. The AASP shall report the true value of the audit sample to the compliance authority. The AASP may report the true value to the source owner, operator, or representative if the AASP's operating plan ensures that no laboratory will receive the same audit sample twice.

(viii) Evaluating the acceptance limits of samples at least once every two years to determine in cooperation with the voluntary consensus standard body if they should be changed;

(ix) Maintaining a database, accessible to the compliance authorities, of results from the audit that shall include the name of the facility tested, the date on which the compliance test was conducted, the name of the company performing the sample collection, the name of the company that analyzed the compliance samples including the audit sample, the measured result for the audit sample, the true value of the audit sample, the acceptance range for the measured value, and whether the testing company passed or failed the audit.

(3) The accrediting body shall have a written technical criteria document that describes how it will ensure that the AASP is operating in accordance with the AASP technical criteria document that describes how audit samples are to be prepared and distributed. This document shall contain standard operating procedures for all of the following operations:

(i) Checking audit samples to confirm their true value as reported by the AASP;

(ii) Performing technical systems audits of the AASP's facilities and operating procedures at least once every two years;

(iii) Providing standards for use by the voluntary consensus standard body to approve the accrediting body that will accredit the audit sample providers.

(4) The technical criteria documents for the accredited sample providers and the accrediting body shall be developed through a public process guided by a voluntary consensus standards body (VCSB). The VCSB shall operate in accordance with the procedures and requirements in the Office of Management and Budget Circular A-119. A copy of Circular A-119 is available upon request by writing the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, by calling (202) 395-6880 or downloading online at *http://standards.gov/standards__gov/a119.cfm.* The VCSB shall approve all accrediting bodies. The Administrator will review all technical criteria documents. If the technical criteria documents do not meet the minimum technical requirements in paragraphs (g)(2) through (4)of this section, the technical criteria documents are not acceptable and the proposed audit sample program is not capable of producing audit samples of sufficient quality to be used in a compliance test. All acceptable technical criteria documents shall be posted on the EPA Web site at the following URL, *http://www.epa.gov/ttn/emc*.

(h) Unless otherwise specified in the applicable subpart, each test location must be verified to be free of cyclonic flow and evaluated for the existence of emission gas stratification and the required number of sampling traverse points. If other procedures are not specified in the applicable subpart to the regulations, use the appropriate procedures in Method 1 to check for cyclonic flow and Method 7E to evaluate emission gas stratification and selection of sampling points.

(i) Whenever the use of multiple calibration gases is required by a test method, performance specification, or quality assurance procedure in a part 60 standard or appendix, Method 205 of 40 CFR part 51, appendix M of this chapter, "Verification of Gas Dilution Systems for Field Instrument Calibrations," may be used.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 9314, Mar. 8, 1974; 42 FR 57126, Nov. 1, 1977; 44 FR 33612, June 11, 1979; 54 FR 6662, Feb. 14, 1989; 54 FR 21344, May 17, 1989; 64 FR 7463, Feb. 12, 1999; 72 FR 27442, May 16, 2007; 75 FR 55646, Sept. 13, 2010; 79 FR 11241, Feb. 27, 2014; 81 FR 59809, Aug. 30, 2016]

§ 60.9 Availability of information.

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§ 60.5 and 60.6 is governed by §§ 2.201 through 2.213 of this chapter and not by § 2.301 of this chapter.)

§ 60.10 State authority.

The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from:

(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

§ 60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined in accordance with performance tests established by § 60.8, unless otherwise specified in the applicable standard.

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in paragraph (e)(5) of this section. For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).

(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating 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, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(e)

(1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in § 60.8 unless one of the following conditions apply. If no performance test under § 60.8 is required, then opacity observations shall be

conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under § 60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in § 60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under § 60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determing compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in paragraph (e)(5) of this section, the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of this part, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in paragraph (e)(3) of this section, the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with paragraph (b) of this section, shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under § 60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected facility shall be included in the notification required in § 60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of paragraph (e)(1) of this section shall apply.

(4) An owner or operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the initial performance test required by § 60.8 and shall furnish the Administrator a written report of the monitoring results along with Method 9 and § 60.8 performance test results.

(5) An owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under § 60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the

Administrator of that decision, in writing, at least 30 days before any performance test required under § 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under § 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under § 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under § 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in § 60.13(c) of this part, that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine compliance with the opacity standard.

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by § 60.8, the opacity observation results and observer certification required by § 60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by § 60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with § 60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, he shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the FEDERAL REGISTER.

(f) Special provisions set forth under an applicable subpart shall supersede any conflicting provisions in paragraphs (a) through (e) of this section.

(g) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[38 FR 28565, Oct. 15, 1973, as amended at 39 FR 39873, Nov. 12, 1974; 43 FR 8800, Mar. 3, 1978; 45 FR 23379, Apr. 4, 1980; 48 FR 48335, Oct. 18, 1983; 50 FR 53113, Dec. 27, 1985; 51 FR 1790, Jan. 15, 1986; 52 FR 9781, Mar. 26, 1987; 62 FR 8328, Feb. 24, 1997; 65 FR 61749, Oct. 17, 2000]

§ 60.12 Circumvention.

No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

[39 FR 9314, Mar. 8, 1974]

§ 60.13 Monitoring requirements.

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B to this part and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to this part, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under § 60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(c) If the owner or operator of an affected facility elects to submit continous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under § 60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, appendix B, of this part before the performance test required under § 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under § 60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of this part, The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under § 60.8 and as described in § 60.11(e)(5) shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in paragraph (c) of this section at least 10 days before the performance test required under § 60.8 is conducted.

(2) Except as provided in paragraph (c)(1) of this section, the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.

(d)

(1) Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once each operating day in accordance with a written procedure. The zero and span must, at a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification in appendix B of this part. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. Owners and operators of a COMS installed in accordance with the provisions of this part must 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 defined in the applicable version of PS-1 in appendix B of this part. For a COMS, the optical surfaces, exposed to the effluent gases, must be cleaned before performing the zero and upscale drift adjustments, except for systems using automatic zero adjustments. The optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures must be followed for a COMS. Minimum procedures must include an automated method for producing a simulated zero opacity condition and an upscale opacity condition using a certified neutral density filter or other related technique to produce a known obstruction of the light beam. Such procedures must provide a system check of all active analyzer internal optics with power or curvature, all active electronic circuitry including the light source and photodetector assembly, and electronic or electro-mechanical systems and hardware and or software used during normal measurement operation.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under paragraph (d) of this section, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by paragraph (c) of this section for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by paragraph (c) of this section for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of this part shall be used.

(g) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.

(h)

(1) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in § 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period.

(2) For continuous monitoring systems other than opacity, 1-hour averages shall be computed as follows, except that the provisions pertaining to the validation of partial operating hours are only applicable for affected facilities that are required by the applicable subpart to include partial hours in the emission calculations:

(i) Except as provided under paragraph (h)(2)(iii) of this section, for a full operating hour (any clock hour with 60 minutes of unit operation), at least four valid data points are required to calculate the hourly average, *i.e.*, one data point in each of the 15-minute quadrants of the hour.

(ii) Except as provided under paragraph (h)(2)(iii) of this section, for a partial operating hour (any clock hour with less than 60 minutes of unit operation), at least one valid data point in each 15-minute quadrant of the hour in which the unit operates is required to calculate the hourly average.

(iii) For any operating hour in which required maintenance or quality-assurance activities are performed:

(A) If the unit operates in two or more quadrants of the hour, a minimum of two valid data points, separated by at least 15 minutes, is required to calculate the hourly average; or

(B) If the unit operates in only one quadrant of the hour, at least one valid data point is required to calculate the hourly average.

(iv) If a daily calibration error check is failed during any operating hour, all data for that hour shall be invalidated, unless a subsequent calibration error test is passed in the same hour and the requirements of paragraph (h)(2)(iii) of this section are met, based solely on valid data recorded after the successful calibration.

(v) For each full or partial operating hour, all valid data points shall be used to calculate the hourly average.

(vi) Except as provided under paragraph (h)(2)(vii) of this section, data recorded during periods of continuous monitoring system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph.

(vii) Owners and operators complying with the requirements of § 60.7(f)(1) or (2) must include any data recorded during periods of monitor breakdown or malfunction in the data averages.

(viii) When specified in an applicable subpart, hourly averages for certain partial operating hours shall not be computed or included in the emission averages (e.g., hours with < 30 minutes of unit operation under § 60.47b(d)).

(ix) Either arithmetic or integrated averaging of all data may be used to calculate the hourly averages. The data may be recorded in reduced or nonreduced form (e.g., ppm pollutant and percent O_2 or ng/J of pollutant).

(3) All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the applicable subpart. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit.

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

(1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases.

(2) Alternative monitoring requirements when the affected facility is infrequently operated.

(3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(5) Alternative methods of converting pollutant concentration measurements to units of the standards.

(6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

(8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities is released to the atmosphere through more than one point.

(j) An alternative to the relative accuracy (RA) test specified in Performance Specification 2 of appendix B may be requested as follows:

(1) An alternative to the reference method tests for determining RA is available for sources with emission rates demonstrated to be less than 50 percent of the applicable standard. A source owner or operator may petition the Administrator to waive the RA test in Section 8.4 of Performance Specification 2 and substitute the procedures in Section 16.0 if the results of a performance test conducted according to the requirements in § 60.8 of this subpart or other tests performed following the criteria in § 60.8 demonstrate that the emission rate of the pollutant of interest in the units of the applicable standard is less than 50 percent of the applicable standard. For sources subject to standards expressed as control efficiency levels, a source owner or operator may petition the Administrator to waive the RA test and substitute the procedures in Section 16.0 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the continuous emission monitoring system is used to determine compliance continuously with the applicable

standard. The petition to waive the RA test shall include a detailed description of the procedures to be applied. Included shall be location and procedure for conducting the alternative, the concentration or response levels of the alternative RA materials, and the other equipment checks included in the alternative procedure. The Administrator will review the petition for completeness and applicability. The determination to grant a waiver will depend on the intended use of the CEMS data (e.g., data collection purposes other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).

(2) The waiver of a CEMS RA test will be reviewed and may be rescinded at such time, following successful completion of the alternative RA procedure, that the CEMS data indicate that the source emissions are approaching the level. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as specified by the applicable regulation(s). For sources subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., §§ 60.45(g) (2) and (3), 60.73(e), and 60.84(e)]. It is the responsibility of the source operator to maintain records and determine the level of emissions relative to the criterion on the waiver of RA testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a RA test of the CEMS as specified in Section 8.4 of Performance Specification 2.

[40 FR 46255, Oct. 6, 1975]

Editorial Note: For Federal Register citations affecting § 60.13, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at *www.govinfo.gov*.

§ 60.14 Modification.

(a) Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

(b) Emission rate shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of “Compilation of Air Pollutant Emission Factors,” EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrates that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in paragraph (b)(1) of this section does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational

change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in paragraph (b)(1) of this section. When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in appendix C of this part shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

(d) [Reserved]

(e) The following shall not, by themselves, be considered modifications under this part:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of paragraph (c) of this section and § 60.15.

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by § 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in paragraph (a) of this section, compliance with all applicable standards must be achieved.

(h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

(i) Repowering projects that are awarded funding from the Department of Energy as permanent clean coal technology demonstration projects (or similar projects funded by EPA) are exempt from the requirements of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the five years prior to the change.

(j)

(1) Repowering projects that qualify for an extension under section 409(b) of the Clean Air Act are exempt from the requirements of this section, provided that such change does not increase the actual hourly emissions of any pollutant regulated under this section above the actual hourly emissions achievable at that unit during the 5 years prior to the change.

(2) This exemption shall not apply to any new unit that:

(i) Is designated as a replacement for an existing unit;

(ii) Qualifies under section 409(b) of the Clean Air Act for an extension of an emission limitation compliance date under section 405 of the Clean Air Act; and

(iii) Is located at a different site than the existing unit.

(k) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project is exempt from the requirements of this section. A *temporary clean coal control technology demonstration project*, for the purposes of this section is a clean coal technology demonstration project that is operated for a period of 5 years or less, and which complies with the State implementation plan for the State in which the project is located and other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(l) The reactivation of a very clean coal-fired electric utility steam generating unit is exempt from the requirements of this section.

[40 FR 58419, Dec. 16, 1975, as amended at 43 FR 34347, Aug. 3, 1978; 45 FR 5617, Jan. 23, 1980; 57 FR 32339, July 21, 1992; 65 FR 61750, Oct. 17, 2000]

§ 60.15 Reconstruction.

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) “Reconstruction” means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) “Fixed capital cost” means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by paragraph (d) of this section and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under paragraph (e) shall be based on:

(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;

(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;

(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and

(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

[40 FR 58420, Dec. 16, 1975]

§ 60.16 Priority list.

Prioritized Major Source Categories

Priority Number [1]	*Source Category*
1.	Synthetic Organic Chemical Manufacturing Industry (SOCMI) and Volatile Organic Liquid Storage Vessels and Handling Equipment
	(a) SOCMI unit processes
	(b) Volatile organic liquid (VOL) storage vessels and handling equipment
	(c) SOCMI fugitive sources
	(d) SOCMI secondary sources

Priority Number [1]	*Source Category*
2.	Industrial Surface Coating: Cans
3.	Petroleum Refineries: Fugitive Sources
4.	Industrial Surface Coating: Paper
5.	Dry Cleaning
	(a) Perchloroethylene
	(b) Petroleum solvent
6.	Graphic Arts
7.	Polymers and Resins: Acrylic Resins
8.	Mineral Wool (Deleted)
9.	Stationary Internal Combustion Engines
10.	Industrial Surface Coating: Fabric
11.	Industrial-Commercial-Institutional Steam Generating Units.
12.	Incineration: Non-Municipal (Deleted)
13.	Non-Metallic Mineral Processing
14.	Metallic Mineral Processing
15.	Secondary Copper (Deleted)
16.	Phosphate Rock Preparation
17.	Foundries: Steel and Gray Iron
18.	Polymers and Resins: Polyethylene
19.	Charcoal Production
20.	Synthetic Rubber
	(a) Tire manufacture
	(b) SBR production
21.	Vegetable Oil
22.	Industrial Surface Coating: Metal Coil
23.	Petroleum Transportation and Marketing
24.	By-Product Coke Ovens
25.	Synthetic Fibers
26.	Plywood Manufacture
27.	Industrial Surface Coating: Automobiles
28.	Industrial Surface Coating: Large Appliances
29.	Crude Oil and Natural Gas Production
30.	Secondary Aluminum
31.	Potash (Deleted)
32.	Lightweight Aggregate Industry: Clay, Shale, and Slate[2]
33.	Glass
34.	Gypsum
35.	Sodium Carbonate
36.	Secondary Zinc (Deleted)

Priority Number [1]	*Source Category*
37.	Polymers and Resins: Phenolic
38.	Polymers and Resins: Urea-Melamine
39.	Ammonia (Deleted)
40.	Polymers and Resins: Polystyrene
41.	Polymers and Resins: ABS-SAN Resins
42.	Fiberglass
43.	Polymers and Resins: Polypropylene
44.	Textile Processing
45.	Asphalt Processing and Asphalt Roofing Manufacture
46.	Brick and Related Clay Products
47.	Ceramic Clay Manufacturing (Deleted)
48.	Ammonium Nitrate Fertilizer
49.	Castable Refractories (Deleted)
50.	Borax and Boric Acid (Deleted)
51.	Polymers and Resins: Polyester Resins
52.	Ammonium Sulfate
53.	Starch
54.	Perlite
55.	Phosphoric Acid: Thermal Process (Deleted)
56.	Uranium Refining
57.	Animal Feed Defluorination (Deleted)
58.	Urea (for fertilizer and polymers)
59.	Detergent (Deleted)
Other Source Categories	
Lead acid battery manufacture[3]	
Organic solvent cleaning[3]	
Industrial surface coating: metal furniture[3]	
Stationary gas turbines[4]	
Municipal solid waste landfills[4]	

[1] Low numbers have highest priority, e.g., No. 1 is high priority, No. 59 is low priority.

[2] Formerly titled “Sintering: Clay and Fly Ash”.

[3] Minor source category, but included on list since an NSPS is being developed for that source category.

[4] Not prioritized, since an NSPS for this major source category has already been promulgated.

[47 FR 951, Jan. 8, 1982, as amended at 47 FR 31876, July 23, 1982; 51 FR 42796, Nov. 25, 1986; 52 FR 11428, Apr. 8, 1987; 61 FR 9919, Mar. 12, 1996]

§ 60.17 Incorporations by reference.

Link to an amendment published at 89 FR 40027, May 9, 2024.

Link to an amendment published at 89 FR 43067, May 16, 2024.

(a) 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 EPA must publish notice of change 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, telephone: 202-566-1744. For information on the availability of this material at NARA, visit *www.archives.gov/federal-register/cfr/ibr-locations.html* or email *fr.inspection@nara.gov*. The material may be obtained from the sources in the following paragraphs of this section.

(b) American Gas Association, available through ILI Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:

(1) American Gas Association Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (1990), IBR approved for § 60.107a(d).

(2) American Gas Association Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 2: Specification and Installation Requirements (2000), IBR approved for § 60.107a(d).

(3) American Gas Association Report No. 11: Measurement of Natural Gas by Coriolis Meter (2003), IBR approved for § 60.107a(d).

(4) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Revised February 2006), IBR approved for § 60.107a(d).

(c) American Hospital Association (AHA) Service, Inc., Post Office Box 92683, Chicago, Illinois 60675-2683. You may inspect a copy at the EPA's Air and Radiation Docket and Information Center (Docket A-91-61, Item IV-J-124), Room M-1500, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

(1) An Ounce of Prevention: Waste Reduction Strategies for Health Care Facilities. American Society for Health Care Environmental Services of the American Hospital Association. Chicago, Illinois. 1993. AHA Catalog No. 057007. ISBN 0-87258-673-5. IBR approved for §§ 60.35e and 60.55c.

(2) [Reserved]

(d) The following material is available for purchase from the American National Standards Institute (ANSI), 25 W. 43rd Street, 4th Floor, New York, NY 10036, Telephone (212) 642-4980, and is also available at the following Web site: *http://www.ansi.org*.

(1) ANSI No. C12.20-2010 American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes (Approved August 31, 2010), IBR approved for § 60.5535(d).

(2) [Reserved]

(e) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005.

(1) API Publication 2517, Evaporation Loss from External Floating Roof Tanks, Second Edition, February 1980, IBR approved for §§ 60.111(i), 60.111a(f), and 60.116b(e).

(2) API Manual of Petroleum Measurement Standards, Chapter 14—Natural Gas Fluids Measurement, Section 1—Collecting and Handling of Natural Gas Samples for Custody Transfer, 7th Edition, May 2016, IBR approved for § 60.4415(a).

(3) API Manual of Petroleum Measurement Standards, Chapter 22—Testing Protocol, Section 2—Differential Pressure Flow Measurement Devices, First Edition, August 2005, IBR approved for § 60.107a(d).

(f) American Public Health Association, 1015 18th Street NW., Washington, DC 20036.

(1) "Standard Methods for the Examination of Water and Wastewater," 16th edition, 1985. Method 303F: "Determination of Mercury by the Cold Vapor Technique." Incorporated by reference for appendix A-8 to part 60, Method 29, §§ 9.2.3, 10.3, and 11.1.3.

(2) 2540 G. Total, Fixed, and Volatile Solids in Solid and Semisolid Samples, in Standard Methods for the Examination of Water and Wastewater, 20th Edition, 1998, IBR approved for § 60.154(b).

(g) 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) ASME Interim Supplement 19.5 on Instruments and Apparatus: Application, Part II of Fluid Meters, 6th Edition (1971), IBR approved for §§ 60.58a(h), 60.58b(i), 60.1320(a), and 60.1810(a).

(2) ASME MFC-3M-2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, IBR approved for § 60.107a(d).

(3) ASME/ANSI MFC-4M-1986 (Reaffirmed 2008), Measurement of Gas Flow by Turbine Meters, IBR approved for § 60.107a(d).

(4) ASME/ANSI MFC-5M-1985 (Reaffirmed 2006), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, IBR approved for § 60.107a(d).

(5) ASME MFC-6M-1998 (Reaffirmed 2005), Measurement of Fluid Flow in Pipes Using Vortex Flowmeters, IBR approved for § 60.107a(d).

(6) ASME/ANSI MFC-7M-1987 (Reaffirmed 2006), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles, IBR approved for § 60.107a(d).

(7) ASME/ANSI MFC-9M-1988 (Reaffirmed 2006), Measurement of Liquid Flow in Closed Conduits by Weighing Method, IBR approved for § 60.107a(d).

(8) ASME MFC-11M-2006, Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters, IBR approved for § 60.107a(d).

(9) ASME MFC-14M-2003, Measurement of Fluid Flow Using Small Bore Precision Orifice Meters, IBR approved for § 60.107a(d).

(10) ASME MFC-16-2007, Measurement of Liquid Flow in Closed Conduits with Electromagnetic Flowmeters, IBR approved for § 60.107a(d).

(11) ASME MFC-18M-2001, Measurement of Fluid Flow Using Variable Area Meters, IBR approved for § 60.107a(d).

(12) ASME MFC-22-2007, Measurement of Liquid by Turbine Flowmeters, IBR approved for § 60.107a(d).

(13) ASME PTC 4.1-1964 (Reaffirmed 1991), Power Test Codes: Test Code for Steam Generating Units (with 1968 and 1969 Addenda), IBR approved for §§ 60.46b, 60.58a(h), 60.58b(i), 60.1320(a), and 60.1810(a).

(14) ASME/ANSI PTC 19.10-1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], Issued August 31, 1981;, IBR approved for §§ 60.56c(b); 60.63(f); 60.106(e); 60.104a(d), (h), (i), and (j); 60.105a(b), (d), (f), and (g); 60.106a(a); 60.107a(a), (c), and (d); 60.275(e); 60.275a(e); 60.275b(e); tables 1 and 3 to subpart EEEE; tables 2 and 4 to subpart FFFF; table 2 to subpart JJJJ; §§ 60.285a(f); 60.396(a); 60.2145(s) and (t); 60.2710(s) and (t); 60.2730(q); 60.4415(a); 60.4900(b); 60.5220(b); tables 1 and 2 to subpart LLLL; tables 2 and 3 to subpart MMMM; §§ 60.5406(c); 60.5406a(c); 60.5406b(c); 60.5407a(g); 60.5407b(g); 60.5413(b); 60.5413a(b) and (d); 60.5413b(b) and (d); §§ 60.5413c(b) and (d).

(15) ASME PTC 22-2014, Gas Turbines: Performance Test Codes, (Issued December 31, 2014), IBR approved for § 60.5580.

(16) ASME PTC 46-1996, Performance Test Code on Overall Plant Performance, (Issued October 15, 1997), IBR approved for § 60.5580.

(17) ASME QRO-1-1994, Standard for the Qualification and Certification of Resource Recovery Facility Operators, IBR approved for §§ 60.54b(a) and (b), 60.56a, 60.1185(a) and (c), and 60.1675(a) and (c).

(h) ASTM International, 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-2959; phone: (800) 262-1373; website: *www.astm.org*.

(1) ASTM A99-76, Standard Specification for Ferromanganese, IBR approved for § 60.261.

(2) ASTM A99-82 (Reapproved 1987), Standard Specification for Ferromanganese, IBR approved for § 60.261.

(3) ASTM A100-69, Standard Specification for Ferrosilicon, IBR approved for § 60.261.

(4) ASTM A100-74, Standard Specification for Ferrosilicon, IBR approved for § 60.261.

(5) ASTM A100-93, Standard Specification for Ferrosilicon, IBR approved for § 60.261.

(6) ASTM A101-73, Standard Specification for Ferrochromium, IBR approved for § 60.261.

(7) ASTM A101-93, Standard Specification for Ferrochromium, IBR approved for § 60.261.

(8) ASTM A482-76, Standard Specification for Ferrochromesilicon, IBR approved for § 60.261.

(9) ASTM A482-93, Standard Specification for Ferrochromesilicon, IBR approved for § 60.261.

(10) ASTM A483-64, Standard Specification for Silicomanganese, IBR approved for § 60.261.

(11) ASTM A483-74 (Reapproved 1988), Standard Specification for Silicomanganese, IBR approved for § 60.261.

(12) ASTM A495-76, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved for § 60.261.

(13) ASTM A495-94, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved for § 60.261.

(14) ASTM D86-78, Distillation of Petroleum Products, IBR approved for §§ 60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).

(15) ASTM D86-82, Distillation of Petroleum Products, IBR approved for §§ 60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).

(16) ASTM D86-90, Distillation of Petroleum Products, IBR approved for §§ 60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).

(17) ASTM D86-93, Distillation of Petroleum Products, IBR approved for §§ 60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).

(18) ASTM D86-95, Distillation of Petroleum Products, IBR approved for §§ 60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).

(19) ASTM D86-96, Distillation of Petroleum Products, approved April 10, 1996; IBR approved for §§ 60.562-2(d). 60.593(d). 60.593a(d); 60.633(h); 60.5401(f); 60.5401a(f); 60.5402b(d); 60.5402c(d).

(20) ASTM D129-64, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§ 60.106(j) and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(21) ASTM D129-78, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§ 60.106(j) and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(22) ASTM D129-95, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§ 60.106(j) and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(23) ASTM D129-00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for § 60.335(b).

(24) ASTM D129-00 (Reapproved 2005), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for § 60.4415(a).

(25) ASTM D240-76, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §§ 60.46(c), 60.296(b), and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(26) ASTM D240-92, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §§ 60.46(c), 60.296(b), and appendix A-7: Method 19, Section 12.5.2.2.3.

(27) ASTM D240-02 (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, (Approved May 1, 2007), IBR approved for § 60.107a(d).

(28) ASTM D270-65, Standard Method of Sampling Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.1.

(29) ASTM D270-75, Standard Method of Sampling Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.1.

(30) ASTM D323-82, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved for §§ 60.111(l), 60.111a(g), 60.111b, and 60.116b(f).

(31) ASTM D323-94, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved for §§ 60.111(l), 60.111a(g), 60.111b, and 60.116b(f).

(32) ASTM D388-77, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(33) ASTM D388-90, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(34) ASTM D388-91, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(35) ASTM D388-95, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(36) ASTM D388-98a, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(37) ASTM D388-99 (Reapproved 2004) [1] Standard Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, 60.251, and 60.5580.

(38) ASTM D396-78, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).

(39) ASTM D396-89, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).

(40) ASTM D396-90, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).

(41) ASTM D396-92, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).

(42) ASTM D396-98, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), 60.111a(b), and 60.5580.

(43) ASTM D975-78, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.111(b) and 60.111a(b).

(44) ASTM D975-96, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.111(b) and 60.111a(b).

(45) ASTM D975-98a, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.111(b) and 60.111a(b).

(46) ASTM D975-08a, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.41b 60.41c, and 60.5580.

(47) ASTM D1072-80, Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.335(b).

(48) ASTM D1072-90 (Reapproved 1994), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.335(b).

(49) ASTM D1072-90 (Reapproved 1999), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.4415(a).

(50) ASTM D1137-53, Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved for § 60.45(f).

(51) ASTM D1137-75, Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved for § 60.45(f).

(52) ASTM D1193-77, Standard Specification for Reagent Water, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; appendix A-4 to part 60: Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; appendix A-5 to part 60: Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; appendix A-8 to part 60: Method 26, Section 7.1.2; Method 26A, Section 7.1.2; and Method 29, Section 7.2.2.

(53) ASTM D1193-91, Standard Specification for Reagent Water, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; appendix A-4 to part 60: Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; appendix A-5 to part 60: Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; appendix A-8 to part 60: Method 26, Section 7.1.2; Method 26A, Section 7.1.2; and Method 29, Section 7.2.2.

(54) ASTM D1266-87, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§ 60.106(j) and 60.335(b).

(55) ASTM D1266-91, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§ 60.106(j) and 60.335(b).

(56) ASTM D1266-98, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§ 60.106(j) and 60.335(b).

(57) ASTM D1266-98 (Reapproved 2003)$^{\varepsilon,1}$ Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for § 60.4415(a).

(58) ASTM D1475-60 (Reapproved 1980), Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for § 60.435(d), appendix A-7 to part 60: Method 24, Section 6.1; and Method 24A, Sections 6.5 and 7.1.

(59) ASTM D1475-90, Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for § 60.435(d), appendix A-7 to part 60: Method 24, Section 6.1; and Method 24A, §§ 6.5 and 7.1.

(60) ASTM D1475-13, Standard Test Method for Density of Liquid Coatings, Inks, and Related Products, Approved November 1, 2013; IBR approved for § 60.393a(f).

(61) ASTM D1552-83, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§ 60.106(j), 60.335(b), and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(62) ASTM D1552-95, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§ 60.106(j), 60.335(b), and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(63) ASTM D1552-01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§ 60.106(j), 60.335(b), and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(64) ASTM D1552-03, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for § 60.4415(a).

(65) ASTM D1826-77, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §§ 60.45(f), 60.46(c), 60.296(b), and appendix A-7 to part 60: Method 19, Section 12.3.2.4.

(66) ASTM D1826-94, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §§ 60.45(f), 60.46(c), 60.296(b), and appendix A-7 to part 60: Method 19, Section 12.3.2.4.

(67) ASTM D1826-94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, (Approved May 10, 2003), IBR approved for § 60.107a(d).

(68) ASTM D1835-87, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§ 60.41Da, 60.41b, and 60.41c.

(69) ASTM D1835-91, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§ 60.41Da, 60.41b, and 60.41c.

(70) ASTM D1835-97, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§ 60.41Da, 60.41b, and 60.41c.

(71) ASTM D1835-03a, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§ 60.41Da, 60.41b, and 60.41c.

(72) ASTM D1945-64, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 60.45(f).

(73) ASTM D1945-76, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 60.45(f).

(74) ASTM D1945-91, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 60.45(f).

(75) ASTM D1945-96, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 60.45(f).

(76) ASTM D1945-03 (Reapproved 2010), Standard Method for Analysis of Natural Gas by Gas Chromatography, approved January 1, 2010; IBR approved for §§ 60.107a(d); 60.5413(d); 60.5413a(d); 60.5413b(d); 60.5413c(d).

(77) ASTM D1945-14 (Reapproved 2019), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, approved December 1, 2019; IBR approved for §§ 60.5417b(d); 60.5417c(d).

(78) ASTM D1946-77, Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§ 60.18(f), 60.45(f), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).

(79) ASTM D1946-90 (Reapproved 1994), Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§ 60.18(f), 60.45(f), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).

(80) ASTM D1946-90 (Reapproved 2006), Standard Method for Analysis of Reformed Gas by Gas Chromatography, (Approved June 1, 2006), IBR approved for § 60.107a(d).

(81) ASTM D2013-72, Standard Method of Preparing Coal Samples for Analysis, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(82) ASTM D2013-86, Standard Method of Preparing Coal Samples for Analysis, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(83) ASTM D2015-77 (Reapproved 1978), Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved for §§ 60.45(f), 60.46(c), and appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(84) ASTM D2015-96, Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved for §§ 60.45(f), 60.46(c), and appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(85) ASTM D2016-74, Standard Test Methods for Moisture Content of Wood, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.

(86) ASTM D2016-83, Standard Test Methods for Moisture Content of Wood, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.

(87) ASTM D2234-76, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.1.

(88) ASTM D2234-96, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.1.

(89) ASTM D2234-97b, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.1.

(90) ASTM D2234-98, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.1.

(91) ASTM D2369-81, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.

(92) ASTM D2369-87, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.

(93) ASTM D2369-90, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.

(94) ASTM D2369-92, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.

(95) ASTM D2369-93, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.

(96) ASTM D2369-95, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.

(97) ASTM D2369-10 (Reapproved 2015)e1, Standard Test Method for Volatile Content of Coatings, (Approved June 1, 2015); IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.

(98) ASTM D2369-20, Standard Test Method for Volatile Content of Coatings, Approved June 1, 2020; IBR approved for §§ 60.393a(f); 60.723(b); 60.724(a); 60.725(b); 60.723a(b); 60.724a(a); 60.725a(b).

(99) ASTM D2382-76, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§ 60.18(f), 60.485(g), 60.485a(g), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).

(100) ASTM D2382-88, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§ 60.18(f), 60.485(g), 60.485a(g), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).

(101) ASTM D2504-67, Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§ 60.485(g) and 60.485a(g).

(102) ASTM D2504-77, Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§ 60.485(g) and 60.485a(g).

(103) ASTM D2504-88 (Reapproved 1993), Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§ 60.485(g) and 60.485a(g).

(104) ASTM D2584-68(Reapproved 1985), Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for § 60.685(c).

(105) ASTM D2584-94, Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for § 60.685(c).

(106) ASTM D2597-94 (Reapproved 1999), Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, IBR approved for § 60.335(b).

(107) ASTM D2622-87, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§ 60.106(j) and 60.335(b).

(108) ASTM D2622-94, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§ 60.106(j) and 60.335(b).

(109) ASTM D2622-98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§ 60.106(j) and 60.335(b).

(110) ASTM D2622-05, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.4415(a).

(111) ASTM D2697-22, Standard Test Method for Volume Nonvolatile Matter in Clear or Pigmented Coatings, Approved July 1, 2022; IBR approved for §§ 60.393a(g); 60.723(b); 60.724(a); 60.725(b); 60.723a(b); 60.724a(a); 60.725a(b).

(112) ASTM D2879-83, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, approved 1983; IBR approved for §§ 60.111b(f); 60.116b(e) and (f); 60.485(e); 60.485a(e); 60.5403b(d); 60.5406c(d).

(113) ASTM D2879-96, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, approved 1996; IBR approved for §§ 60.111b(f); 60.116b(e) and (f); 60.485(e); 60.485a(e); 60.5403b(d); 60.5406c(d).

(114) ASTM D2879-97, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, approved 1997; IBR approved for §§ 60.111b(f); 60.116b(e) and (f); 60.485(e); 60.485a(e); 60.5403b(d); 60.5406c(d).

(115) ASTM D2880-78, Standard Specification for Gas Turbine Fuel Oils, IBR approved for §§ 60.111(b), 60.111a(b), and 60.335(d).

(116) ASTM D2880-96, Standard Specification for Gas Turbine Fuel Oils, IBR approved for §§ 60.111(b), 60.111a(b), and 60.335(d).

(117) ASTM D2908-74, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for § 60.564(j).

(118) ASTM D2908-91, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for § 60.564(j).

(119) ASTM D2986-71, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.1; appendix A-5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(120) ASTM D2986-78, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.1; appendix A-5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(121) ASTM D2986-95a, Standard Method for Evaluation of Air, AssaMedia by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.1; appendix A-5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(122) ASTM D3173-73, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(123) ASTM D3173-87, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(124) ASTM D3176-74, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved for § 60.45(f)(5)(i) and appendix A-7 to part 60: Method 19, Section 12.3.2.3.

(125) ASTM D3176-89, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved for § 60.45(f)(5)(i) and appendix A-7 to part 60: Method 19, Section 12.3.2.3.

(126) ASTM D3177-75, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(127) ASTM D3177-89, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(128) ASTM D3178-73 (Reapproved 1979), Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for § 60.45(f).

(129) ASTM D3178-89, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for § 60.45(f).

(130) ASTM D3246-81, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.335(b).

(131) ASTM D3246-92, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.335(b).

(132) ASTM D3246-96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.335(b).

(133) ASTM D3246-05, Standard Test Method for Sulfur in Petrolum Gas by Oxidative Microcoulometry, IBR approved for § 60.4415(a)(1).

(134) ASTM D3270-73T, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A-5 to part 60: Method 13A, Section 16.1.

(135) ASTM D3270-80, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A-5 to part 60: Method 13A, Section 16.1.

(136) ASTM D3270-91, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A-5 to part 60: Method 13A, Section 16.1.

(137) ASTM D3270-95, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A-5 to part 60: Method 13A, Section 16.1.

(138) ASTM D3286-85, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(139) ASTM D3286-96, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(140) ASTM D3370-76, Standard Practices for Sampling Water, IBR approved for § 60.564(j).

(141) ASTM D3370-95a, Standard Practices for Sampling Water, IBR approved for § 60.564(j).

(142) ASTM D3588-98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, approved May 10, 2003; IBR approved for §§ 60.107a(d); 60.5413(d); 60.5413a(d); 60.5413b(d); 60.5413c(d).

(143) ASTM D3699-08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1, 2008), IBR approved for §§ 60.41b, 60.41c, and 60.5580.

(144) ASTM D3792-79, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for appendix A-7 to part 60: Method 24, Section 6.3.

(145) ASTM D3792-91, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for appendix A-7 to part 60: Method 24, Section 6.3.

(146) ASTM D4017-81, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A-7 to part 60: Method 24, Section 6.4.

(147) ASTM D4017-90, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A-7 to part 60: Method 24, Section 6.4.

(148) ASTM D4017-96a, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A-7 to part 60: Method 24, Section 6.4.

(149) ASTM D4057-81, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(150) ASTM D4057-95, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(151) ASTM D4057-95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for § 60.4415(a).

(152) ASTM D4084-82, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for § 60.334(h).

(153) ASTM D4084-94, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for § 60.334(h).

(154) ASTM D4084-05, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §§ 60.4360 and 60.4415(a).

(155) ASTM D4177-95, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.1.

(156) ASTM D4177-95 (Reapproved 2000), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for § 60.4415(a).

(157) ASTM D4239-85, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(158) ASTM D4239-94, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(159) ASTM D4239-97, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(160) ASTM D4294-02, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.335(b).

(161) ASTM D4294-03, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.4415(a).

(162) ASTM D4442-84, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.

(163) ASTM D4442-92, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.

(164) ASTM D4444-92, Standard Test Methods for Use and Calibration of Hand-Held Moisture Meters, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.

(165) ASTM D4457-85 (Reapproved 1991), Test Method for Determination of Dichloromethane and 1,1,1-Trichloroethane in Paints and Coatings by Direct Injection into a Gas Chromatograph, IBR approved for appendix A-7 to part 60: Method 24, Section 6.5.

(166) ASTM D4468-85 (Reapproved 2000), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, IBR approved for §§ 60.335(b) and 60.4415(a).

(167) ASTM D4468-85 (Reapproved 2006), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, (Approved June 1, 2006), IBR approved for § 60.107a(e).

(168) ASTM D4629-02, Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection, IBR approved for §§ 60.49b(e) and 60.335(b).

(169) ASTM D4809-95, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for §§ 60.18(f), 60.485(g), 60.485a(g), 60.564(f), 60.614(d), 60.664(e), and 60.704(d).

(170) ASTM D4809-06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), (Approved December 1, 2006), IBR approved for § 60.107a(d).

(171) ASTM D4810-88 (Reapproved 1999), Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length of Stain Detector Tubes, IBR approved for §§ 60.4360 and 60.4415(a).

(172) ASTM D4840-99(2018)e1 Standard Guide for Sample Chain-of-Custody Procedures, approved August 2018; IBR approved for Appendix A-7: Method 23.

(173) ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, approved June 1, 2006; IBR approved for §§ 60.107a(d); 60.5413(d); 60.5413a(d); 60.5413b(d); 60.5413c(d).

(174) ASTM D5066-91, Standard Test Method for Determination of the Transfer Efficiency Under Production Conditions for Spray Application of Automotive Paints—Weight Basis, Approved June 1, 2017; IBR approved for § 60.393a(h).

(175) ASTM D5087-02 (Reapproved 2021), Standard Test Method for Determining Amount of Volatile Organic Compound (VOC) Released from Solventborne Automotive Coatings and Available for Removal in a VOC Control Device (Abatement), Approved February 1, 2021; IBR approved for § 60.397a(e); appendix A to subpart MMa.

(176) ASTM D5287-97 (Reapproved 2002), Standard Practice for Automatic Sampling of Gaseous Fuels, IBR approved for § 60.4415(a).

(177) ASTM D5403-93, Standard Test Methods for Volatile Content of Radiation Curable Materials, IBR approved for appendix A-7 to part 60: Method 24, Section 6.6.

(178) ASTM D5453-00, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for § 60.335(b).

(179) ASTM D5453-05, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for § 60.4415(a).

(180) ASTM D5504-01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, IBR approved for §§ 60.334(h) and 60.4360.

(181) ASTM D5504-08, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, (Approved June 15, 2008), IBR approved for §§ 60.107a(e) and 60.5413(d).

(182) ASTM D5623-19, Standard Test Method for Sulfur Compounds in Light Petroleum Liquids by Gas Chromatography and Sulfur Selective Detection, (Approved July 1, 2019); IBR approved for § 60.4415(a).

(183) ASTM D5762-02, Standard Test Method for Nitrogen in Petroleum and Petroleum Products by Boat-Inlet Chemiluminescence, IBR approved for § 60.335(b).

(184) ASTM D5865-98, Standard Test Method for Gross Calorific Value of Coal and Coke, IBR approved for §§ 60.45(f) and 60.46(c), and appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(185) ASTM D5865-10, Standard Test Method for Gross Calorific Value of Coal and Coke, (Approved January 1, 2010), IBR approved for §§ 60.45(f), 60.46(c), and appendix A-7 to part 60: Method 19, section 12.5.2.1.3.

(186) ASTM D5965-02 (Reapproved 2013), Standard Test Methods for Specific Gravity of Coating Powders, Approved June 1, 2013; IBR approved for § 60.393a(f).

(187) ASTM D6093-97 (Reapproved 2016), Standard Test Method for Percent Volume Nonvolatile Matter in Clear or Pigmented Coatings Using a Helium Gas Pycnometer, Approved December 1, 2016; IBR approved for §§ 60.393a(g); 60.723(b); 60.724(a); 60.725(b); 60.723a(b); 60.724a(a); 60.725a(b).

(188) ASTM D6216-20, Standard Practice for Opacity Monitor Manufacturers to Certify Conformance with Design and Performance Specifications, approved September 1, 2020; IBR approved for appendix B to part 60.

(189) ASTM D6228-98, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for § 60.334(h).

(190) ASTM D6228-98 (Reapproved 2003), Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for §§ 60.4360 and 60.4415.

(191) ASTM D6266-00a (Reapproved 2017), Standard Test Method for Determining the Amount of Volatile Organic Compound (VOC) Released From Waterborne Automotive Coatings and Available for Removal in a VOC Control Device (Abatement), Approved July 1, 2017; IBR approved for § 60.397a(e).

(192) ASTM D6348-03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, (Approved October 1, 2003), IBR approved for § 60.73a(b), table 7 to subpart IIII, table 2 to subpart JJJJ, and § 60.4245(d).

(193) ASTM D6348-12e1, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, approved February 1, 2012; IBR approved for § 60.5413c(b).

(194) ASTM D6366-99, Standard Test Method for Total Trace Nitrogen and Its Derivatives in Liquid Aromatic Hydrocarbons by Oxidative Combustion and Electrochemical Detection, IBR approved for § 60.335(b)(9).

(195) ASTM D6420-99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, (Approved October 1, 2004), IBR approved for § 60.107a(d) and table 2 to subpart JJJJ.

(196) ASTM D6522-00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for § 60.335(a).

(197) ASTM D6522-00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, (Approved October 1, 2005), IBR approved for table 2 to subpart JJJJ, §§ 60.5413(b) and (d), and 60.5413a(b).

(198) ASTM D6522-11 Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers (Approved December 1, 2011), IBR approved for § 60.37f(a), 60.766(a).

(199) ASTM D6522-20, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, approved June 1, 2020; IBR approved for §§ 60.5413b(b); 60.5413c(b).

(200) ASTM D6667-01, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for § 60.335(b).

(201) ASTM D6667-04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for § 60.4415(a).

(202) ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, (Approved July 15, 2011), IBR approved for §§ 60.41b, 60.41c, and 60.5580.

(203) ASTM D6784-02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), IBR approved for § 60.56c(b) and appendix B to part 60: Performance Specification 12A, Section 8.6.2.

(204) ASTM D6784-02 (Reapproved 2008), Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), approved April 1, 2008; IBR approved for § 60.56c(b).

(205) 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 appendix B to part 60.

(206) ASTM D6911-15 Standard Guide for Packaging and Shipping Environmental Samples for Laboratory Analysis, approved January 15, 2015; IBR approved for Appendix A-7: Method 23; Appendix A-8: Method 30B.

(207) ASTM D7039-15a, Standard Test Method for Sulfur in Gasoline, Diesel Fuel, Jet Fuel, Kerosine, Boideisel, Biodiesel Blends, and Gasoline-Ethanol Blends by Monochromatic Wavelength Dispersive X-ray Fluorescence Spectrometry, (Approved July 1, 2015); IBR approved for § 60.4415(a).

(208) ASTM D7467-10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, (Approved August 1, 2010), IBR approved for §§ 60.41b, 60.41c, and 60.5580.

(209) 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 §§ 60.123(c)(6); 60.123(c)(6)(i); 60.123(c)(6)(ii); 60.123(c)(6)(v); 60.123a(c)(6)(ii); 60.123a(c)(6)(ii)(A); 60.123a(c)(6)(ii)(B); 60.123a(c)(6)(ii)(E); 60.271(k); 60.272(a) and (b); 60.273(c) and (d); 60.274(h); 60.275(e); 60.276(c); 60.271a; 60.272a(a) and (b); 60.273a(c) and (d); 60.274a(h); 60.275a(e); 60.276a(f); 60.271b; 60.272b(a) and (b); 60.273b(c) and (d); 60.274b(h); 60.275b(e); 60.276b(f); 60.374a(d).

(210) ASTM E168-67, General Techniques of Infrared Quantitative Analysis, IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(211) ASTM E168-77, General Techniques of Infrared Quantitative Analysis, IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(212) ASTM E168-92, General Techniques of Infrared Quantitative Analysis, IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400, 60.5400a(f).

(213) ASTM E168-16, (Reapproved 2023), Standard Practices for General Techniques of Infrared Quantitative Analysis, approved January 1, 2023; IBR approved for §§ 60.5400b(a); 60.5400c(a); 60.5401b(a); 60.5401c(a).

(214) ASTM E169-63, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), and 60.632(f) .

(215) ASTM E169-77, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§ 60.485a(d), 60.593(b), and 60.593a(b), 60.632(f).

(216) ASTM E169-93, General Techniques of Ultraviolet Quantitative Analysis, (Approved May 15, 1993), IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400(f), and 60.5400a(f).

(217) ASTM E169-16 (Reapproved 2022), Standard Practices for General Techniques of Ultraviolet-Visible Quantitative Analysis, approved November 1, 2022; IBR approved for §§ 60.5400b(a); 60.5400c; 60.5401b(a); 60.5401c(a).

(218) ASTM E260-73, General Gas Chromatography Procedures, IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(219) ASTM E260-91, General Gas Chromatography Procedures, (IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(220) ASTM E260-96, General Gas Chromatography Procedures, approved April 10, 1996; IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400(f), 60.5400a(f), 60.5406(b), 60.5406a(b)(3), 60.5400b(a)(2), 60.5401b(a)(2), 60.5406b(b)(3), 60.5400c(a), and 60.5401c(a).

(221) ASTM E617-13, Standard Specification for Laboratory Weights and Precision Mass Standards, approved May 1, 2013, IBR approved for appendix A-3: Methods 4, 5, 5H, 5I, and appendix A-8: Method 29.

(222) ASTM E871-82 (Reapproved 2013), Standard Test Method for Moisture Analysis of Particulate Wood Fuels, (Approved August 15, 2013), IBR approved for appendix A-8: method 28R.

(223) ASTM E1584-11, Standard Test Method for Assay of Nitric Acid, (Approved August 1, 2011), IBR approved for § 60.73a(c).

(224) ASTM E2515-11, Standard Test Method for Determination of Particulate Matter Emissions Collected by a Dilution Tunnel, (Approved November 1, 2011), IBR approved for § 60.534 and § 60.5476.

(225) ASTM E2618-13 Standard Test Method for Measurement of Particulate Matter Emissions and Heating Efficiency of Outdoor Solid Fuel-Fired Hydronic Heating Appliances, (Approved September 1, 2013), IBR approved for § 60.5476.

(226) ASTM E2779-10, Standard Test Method for Determining Particulate Matter Emissions from Pellet Heaters, (Approved October 1, 2010), IBR approved for § 60.534.

(227) ASTM E2780-10, Standard Test Method for Determining Particulate Matter Emissions from Wood Heaters, (Approved October 1, 2010), IBR approved for appendix A: method 28R.

(228) ASTM UOP539-97, Refinery Gas Analysis by Gas Chromatography, (Copyright 1997), IBR approved for § 60.107a(d).

(i) Association of Official Analytical Chemists, 1111 North 19th Street, Suite 210, Arlington, VA 22209.

(1) AOAC Method 9, Official Methods of Analysis of the Association of Official Analytical Chemists (AOAC), 11th edition, 1970, pp. 11-12, IBR approved for §§ 60.204(b), 60.214(b), 60.224(b), and 60.234(b).

(2) [Reserved]

(j) U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue NW, Washington, DC 20460; phone: (202) 272-0167; website: *www.epa.gov*.

(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 Operations, September 2008, Office of Air Quality Planning and Standards (OAQPS); IBR approved for §§ 60.393a(e) and (h); 60.395a(k); 60.397a(e); appendix A to subpart MMa.

(2) EPA-454/B-08-002, Quality Assurance Handbook for Air Pollution Measurement Systems; Volume IV: Meteorological Measurements, Version 2.0 (Final), March 2008; IBR approved for Appendix K to this part.

(3) EPA-454/R-98-015, Office of Air Quality Planning and Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance, September 1997, *https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=2000D5T6.PDF;* IBR approved for §§ 60.124(f); 60.124a(f); 60.273(e); 60.273a(e); 60.273b(e); 60.373a(b); 60.2145(r); 60.2710(r); 60.4905(b); 60.5225(b).

(4) EPA-600/R-12/531, EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards, Issued May 2012; IBR approved for §§ 60.5413(d); 60.5413a(d); 60.5413b(d); 60.5413c(d).

(5) SW-846-6010D, Inductively Coupled Plasma-Optical Emission Spectrometry, Revision 5, July 2018, in EPA Publication No. SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for appendix A-5 to part 60: Method 12.

(6) SW-846-6020B, Inductively Coupled Plasma-Mass Spectrometry, Revision 2, July 2014, in EPA Publication No. SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for appendix A-5 to part 60: Method 12.

(k) GPA Midstream Association (formerly known as Gas Processors Association), Sixty Sixty American Plaza, Suite 700, Tulsa, OK 74135.

Note 1 to paragraph (k): Material in this paragraph that is no longer available from GPA may be available through the reseller HIS Markit, 15 Inverness Way East, P.O. Box 1154, Englewood, CO 80150-1154, *https://global.ihs.com/*. For material that is out-of-print, contact EPA's Air and Radiation Docket and Information Center, Room 3334, 1301 Constitution Ave. NW, Washington, DC 20460 or *a-and-rdocket@epa.gov*.

(1) GPA Midstream Standard 2140-17 (GPA 2140-17), Liquefied Petroleum Gas Specifications and Test Methods, (Revised 2017), IBR approved for § 60.4415(a).

(2) GPA Midstream Standard 2166-17 (GPA 2166-17), Obtaining Natural Gas Samples for Analysis by Gas Chromatography, (Reaffirmed 2017), IBR approved for § 60.4415(a).

(3) Gas Processors Association Standard 2172-09, Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (2009), IBR approved for § 60.107a(d).

(4) GPA Standard 2174-14 (GPA 2174-14), Obtaining Liquid Hydrocarbon Samples for Analysis by Gas Chromatography, (Revised 2014), IBR approved for § 60.4415(a).

(5) GPA Standard 2261-19 (GPA 2261-19), Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, (Revised 2019), IBR approved for § 60.4415(a).

(6) Gas Processors Association Standard 2377-86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, 1986 Revision, IBR approved for §§ 60.105(b), 60.107a(b), 60.334(h), 60.4360, and 60.4415(a).

(l) International Organization for Standardization (ISO) available through IHS Inc., 15 Inverness Way East, Englewood, CO 80112.

(1) ISO 8178-4: 1996(E), Reciprocating Internal Combustion Engines—Exhaust Emission Measurement—part 4: Test Cycles for Different Engine Applications, IBR approved for § 60.4241(b).

(2) ISO 10715:1997(E), Natural gas—Sampling guidelines, (First Edition, June 1, 1997), IBR approved for § 60.4415(a)

(m) International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, + 41 22 749 01 11, *http://www.iso.org/iso/home.htm*.

(1) ISO 2314:2009(E), Gas turbines-Acceptance tests, Third edition (December 15, 2009), IBR approved for § 60.5580.

(2) ISO 8316: Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank (1987-10-01)—First Edition, IBR approved for § 60.107a(d).

(n) This material is available for purchase from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, Virginia 22161. You may inspect a copy at the EPA's Air and Radiation Docket and Information Center (Docket A-91-61, Item IV-J-125), Room M-1500, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

(1) OMB Bulletin No. 93-17: Revised Statistical Definitions for Metropolitan Areas. Office of Management and Budget, June 30, 1993. NTIS No. PB 93-192-664. IBR approved for § 60.31e.

(2) [Reserved]

(o) North American Electric Reliability Corporation, 1325 G Street NW., Suite 600, Washington, DC 20005-3801, *http://www.nerc.com*.

(1) North American Electric Reliability Corporation Reliability Standard EOP-002-3, Capacity and Energy Emergencies, updated November 19, 2012, IBR approved for §§ 60.4211(f) and 60.4243(d). Also available online: *http://www.nerc.com/files/EOP-002-3__1.pdf*.

(2) [Reserved]

(p) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Suite 115, Peachtree Corners, GA 30092, Telephone (800) 332-8686, and is also available at the following Web site: *http://www.tappi.org*.

(1) TAPPI Method T 624 cm-11, (Copyright 2011), IBR approved, for §§ 60.285(d) and 60.285a(d).

(2) [Reserved]

(q) Underwriter's Laboratories, Inc. (UL), 333 Pfingsten Road, Northbrook, IL 60062.

(1) UL 103, Sixth Edition revised as of September 3, 1986, Standard for Chimneys, Factory-built, Residential Type and Building Heating Appliance, IBR approved for appendix A-8 to part 60.

(2) [Reserved]

(r) Water Pollution Control Federation (WPCF), 2626 Pennsylvania Avenue NW., Washington, DC 20037.

(1) Method 209A, Total Residue Dried at 103-105 °C, in Standard Methods for the Examination of Water and Wastewater, 15th Edition, 1980, IBR approved for § 60.683(b).

(2) [Reserved]

(s) West Coast Lumber Inspection Bureau, 6980 SW. Barnes Road, Portland, OR 97223.

(1) West Coast Lumber Standard Grading Rules No. 16, pages 5-21, 90 and 91, September 3, 1970, revised 1984, IBR approved for appendix A-8 to part 60.

(2) [Reserved]

(t) This material is available for purchase from the Canadian Standards Association (CSA), 5060 Spectrum Way, Suite 100, Mississauga, Ontario, Canada L4W 5N6, Telephone: 800-463-6727.

(1) CSA B415.1-10, Performance Testing of Solid-fuel-burning Heating Appliances, (March 2010), IBR approved for § 60.534 and § 60.5476. (The standard is also available at *http://shop.csa.ca/en/canada/fuel-burning-equipment/b4151-10/invt/27013322010*)

(2) [Reserved]

(u) This European National (EN) standards material is available for purchase at European Committee for Standardization, Management Centre, Avenue Marnix 17, B-1000 Brussels, Belgium, Telephone: + 32 2 550 08 11.

(1) DIN EN 303-5:2012E (EN 303-5), Heating boilers—Part 5: Heating boilers for solid fuels, manually and automatically stoked, nominal heat output of up to 500 kW—Terminology, requirements, testing and marking, (October 2012), IBR approved for § 60.5476. (The standard is also available at *http://www.en-standard.eu/csn-en-303-5-heating-boilers-part-5-heating-boilers-for-solid-fuels-manually-and-automatically-stoked-nominal-heat-output-of-up-to-500-kw-terminology-requirements-testing-and-marking/?gclid=CJXI2P__97MMCFdccgQodan8ATA*)

(2) [Reserved]

[79 FR 11242, Feb. 27, 2014]

Editorial Note: For FEDERAL REGISTER citations affecting § 60.17, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at www.govinfo.gov.

§ 60.18 General control device and work practice requirements.

(a) ***Introduction.***

(1) This section contains requirements for control devices used to comply with applicable subparts of 40 CFR parts 60 and 61. The requirements are placed here for administrative convenience and apply only to facilities covered by subparts referring to this section.

(2) This section also contains requirements for an alternative work practice used to identify leaking equipment. This alternative work practice is placed here for administrative convenience and is available to all subparts in 40 CFR parts 60, 61, 63, and 65 that require monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(b) ***Flares.*** Paragraphs (c) through (f) apply to flares.

(c)

(1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

(2) Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).

(3) An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

(i)

(A) Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity, V_{max}, as determined by the following equation:

$$V_{max} = (X_{H2} - K_1) * K_2$$

Where:

V_{max} = Maximum permitted velocity, m/sec.

K_1 = Constant, 6.0 volume-percent hydrogen.

K_2 = Constant, 3.9(m/sec)/volume-percent hydrogen.

X_{H2} = The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in § 60.17).

(B) The actual exit velocity of a flare shall be determined by the method specified in paragraph (f)(4) of this section.

(ii) Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

(4)

(i) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (c)(4) (ii) and (iii) of this section.

(ii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).

(iii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed.

(5) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(6).

(6) Flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted.

(d) Owners or operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices.

(e) Flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(f)

(1) Method 22 of appendix A to this part shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours and shall be used according to Method 22.

(2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

(3) The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

where:

H_T = Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C;

$$K = \text{Constant, } 1.740 \times 10^{-7} \left(\frac{1}{\text{ppm}}\right) \left(\frac{\text{g mole}}{\text{scm}}\right) \left(\frac{\text{MJ}}{\text{kcal}}\right)$$

where the standard temperature for $\left(\frac{\text{g mole}}{\text{scm}}\right)$ is 20°C;

C_i = Concentration of sample component i in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (Incorporated by reference as specified in § 60.17); and

H_i = Net heat of combustion of sample component i, kcal/g mole at 25 °C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 or 88 or D4809-95 (incorporated by reference as specified in § 60.17) if published values are not available or cannot be calculated.

(4) The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.

(5) The maximum permitted velocity, V_{max}, for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation.

$\text{Log}_{10} (V_{max}) = (H_T + 28.8)/31.7$

V_{max} = Maximum permitted velocity, M/sec

28.8 = Constant

31.7 = Constant

H_T = The net heating value as determined in paragraph (f)(3).

(6) The maximum permitted velocity, V_{max}, for air-assisted flares shall be determined by the following equation.

$V_{max} = 8.706 + 0.7084 (H_T)$

V_{max} = Maximum permitted velocity, m/sec

8.706 = Constant

0.7084 = Constant

H_T = The net heating value as determined in paragraph (f)(3).

(g) ***Alternative work practice for monitoring equipment for leaks.*** Paragraphs (g), (h), and (i) of this section apply to all equipment for which the applicable subpart requires monitoring with a 40 CFR part 60, appendix A-7, Method 21 monitor, except for closed vent systems, equipment designated as leakless, and equipment identified in the applicable subpart as having no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background. An owner or operator may use an optical gas imaging instrument instead of a 40 CFR part 60, appendix A-7, Method 21 monitor. Requirements in the existing subparts that are specific to the Method 21 instrument do not apply under this section. All other requirements in the applicable subpart that are not addressed in paragraphs (g), (h), and (i) of this section apply to this standard. For example, equipment specification requirements, and non-Method 21 instrument recordkeeping and reporting requirements in the applicable subpart continue to apply. The terms defined in paragraphs (g)(1) through (5) of this section have meanings that are specific to the alternative work practice standard in paragraphs (g), (h), and (i) of this section.

(1) ***Applicable subpart*** means the subpart in 40 CFR parts 60, 61, 63, or 65 that requires monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(2) ***Equipment*** means pumps, valves, pressure relief valves, compressors, open-ended lines, flanges, connectors, and other equipment covered by the applicable subpart that require monitoring with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(3) ***Imaging*** means making visible emissions that may otherwise be invisible to the naked eye.

(4) ***Optical gas imaging instrument*** means an instrument that makes visible emissions that may otherwise be invisible to the naked eye.

(5) ***Repair*** means that equipment is adjusted, or otherwise altered, in order to eliminate a leak.

(6) ***Leak*** means:

(i) Any emissions imaged by the optical gas instrument;

(ii) Indications of liquids dripping;

(iii) Indications by a sensor that a seal or barrier fluid system has failed; or

(iv) Screening results using a 40 CFR part 60, appendix A-7, Method 21 monitor that exceed the leak definition in the applicable subpart to which the equipment is subject.

(h) The alternative work practice standard for monitoring equipment for leaks is available to all subparts in 40 CFR parts 60, 61, 63, and 65 that require monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(1) An owner or operator of an affected source subject to CFR parts 60, 61, 63, or 65 can choose to comply with the alternative work practice requirements in paragraph (i) of this section instead of using the 40 CFR part 60, appendix A-7, Method 21 monitor to identify leaking equipment. The owner or operator must document the equipment, process units, and facilities for which the alternative work practice will be used to identify leaks.

(2) Any leak detected when following the leak survey procedure in paragraph (i)(3) of this section must be identified for repair as required in the applicable subpart.

(3) If the alternative work practice is used to identify leaks, re-screening after an attempted repair of leaking equipment must be conducted using either the alternative work practice or the 40 CFR part 60, appendix A-7, Method 21 monitor at the leak definition required in the applicable subpart to which the equipment is subject.

(4) The schedule for repair is as required in the applicable subpart.

(5) When this alternative work practice is used for detecting leaking equipment, choose one of the monitoring frequencies listed in Table 1 to subpart A of this part in lieu of the monitoring frequency specified for regulated equipment in the applicable subpart. Reduced monitoring frequencies for good performance are not applicable when using the alternative work practice.

(6) When this alternative work practice is used for detecting leaking equipment the following are not applicable for the equipment being monitored:

(i) Skip period leak detection and repair;

(ii) Quality improvement plans; or

(iii) Complying with standards for allowable percentage of valves and pumps to leak.

(7) When the alternative work practice is used to detect leaking equipment, the regulated equipment in paragraph (h)(1)(i) of this section must also be monitored annually using a 40 CFR part 60, appendix A-7, Method 21 monitor at the leak definition required in the applicable subpart. The owner or operator may choose the specific monitoring period (for example, first quarter) to conduct the annual monitoring. Subsequent monitoring must be conducted every 12 months from the initial period. Owners or operators must keep records of the annual Method 21 screening results, as specified in paragraph (i)(4)(vii) of this section.

(i) An owner or operator of an affected source who chooses to use the alternative work practice must comply with the requirements of paragraphs (i)(1) through (i)(5) of this section.

(1) Instrument Specifications. The optical gas imaging instrument must comply with the requirements in (i)(1)(i) and (i)(1)(ii) of this section.

(i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument check described in paragraph (i)(2) of this section. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.

(ii) Provide a date and time stamp for video records of every monitoring event.

(2) Daily Instrument Check. On a daily basis, and prior to beginning any leak monitoring work, test the optical gas imaging instrument at the mass flow rate determined in paragraph (i)(2)(i) of this section in accordance with the procedure specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each camera configuration used during monitoring (for example, different lenses used), unless an alternative method to demonstrate daily instrument checks has been approved in accordance with paragraph (i)(2)(v) of this section.

(i) Calculate the mass flow rate to be used in the daily instrument check by following the procedures in paragraphs (i)(2)(i)(A) and (i)(2)(i)(B) of this section.

(A) For a specified population of equipment to be imaged by the instrument, determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, within the distance to be used in paragraph (i)(2)(iv)(B) of this section, at or below the standard detection sensitivity level.

(B) Multiply the standard detection sensitivity level, corresponding to the selected monitoring frequency in Table 1 of subpart A of this part, by the mass fraction of detectable chemicals from the stream identified in paragraph (i)(2)(i)(A) of this section to determine the mass flow rate to be used in the daily instrument check, using the following equation.

$$E_{dic} = (E_{sds}) \sum_{i=1}^{k} x_i$$

Where:

E_{dic} = Mass flow rate for the daily instrument check, grams per hour

x_i = Mass fraction of detectable chemical(s) i seen by the optical gas imaging instrument, within the distance to be used in paragraph (i)(2)(iv)(B) of this section, at or below the standard detection sensitivity level, E_{sds}.

E_{sds} = Standard detection sensitivity level from Table 1 to subpart A, grams per hour

k = Total number of detectable chemicals emitted from the leaking equipment and seen by the optical gas imaging instrument.

(ii) Start the optical gas imaging instrument according to the manufacturer's instructions, ensuring that all appropriate settings conform to the manufacturer's instructions.

(iii) Use any gas chosen by the user that can be viewed by the optical gas imaging instrument and that has a purity of no less than 98 percent.

(iv) Establish a mass flow rate by using the following procedures:

(A) Provide a source of gas where it will be in the field of view of the optical gas imaging instrument.

(B) Set up the optical gas imaging instrument at a recorded distance from the outlet or leak orifice of the flow meter that will not be exceeded in the actual performance of the leak survey. Do not exceed the operating parameters of the flow meter.

(C) Open the valve on the flow meter to set a flow rate that will create a mass emission rate equal to the mass rate specified in paragraph (i)(2)(i) of this section while observing the gas flow through the optical gas imaging instrument viewfinder. When an image of the gas emission is seen through the viewfinder at the required emission rate, make a record of the reading on the flow meter.

(v) Repeat the procedures specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each configuration of the optical gas imaging instrument used during the leak survey.

(vi) To use an alternative method to demonstrate daily instrument checks, apply to the Administrator for approval of the alternative under § 60.13(i).

(3) Leak Survey Procedure. Operate the optical gas imaging instrument to image every regulated piece of equipment selected for this work practice in accordance with the instrument manufacturer's operating parameters. All emissions imaged by the optical gas imaging instrument are considered to be leaks and are subject to repair. All emissions visible to the naked eye are also considered to be leaks and are subject to repair.

(4) Recordkeeping. You must keep the records described in paragraphs (i)(4)(i) through (i)(4)(vii) of this section:

(i) The equipment, processes, and facilities for which the owner or operator chooses to use the alternative work practice.

(ii) The detection sensitivity level selected from Table 1 to subpart A of this part for the optical gas imaging instrument.

(iii) The analysis to determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, as specified in paragraph (i)(2)(i)(A) of this section.

(iv) The technical basis for the mass fraction of detectable chemicals used in the equation in paragraph (i)(2)(i)(B) of this section.

(v) The daily instrument check. Record the distance, per paragraph (i)(2)(iv)(B) of this section, and the flow meter reading, per paragraph (i)(2)(iv)(C) of this section, at which the leak was imaged. Keep a video record of the daily instrument check for each configuration of the optical gas imaging instrument used during the leak survey (for example, the daily instrument check must be conducted for each lens used). The video record must include a time and date stamp for each daily instrument check. The video record must be kept for 5 years.

(vi) Recordkeeping requirements in the applicable subpart. A video record must be used to document the leak survey results. The video record must include a time and date stamp for each monitoring event. A video record can be used to meet the recordkeeping requirements of the applicable subparts if each piece of regulated equipment selected for this work practice can be identified in the video record. The video record must be kept for 5 years.

(vii) The results of the annual Method 21 screening required in paragraph (h)(7) of this section. Records must be kept for all regulated equipment specified in paragraph (h)(1) of this section. Records must identify the equipment screened, the screening value measured by Method 21, the time and date of the screening, and calibration information required in the existing applicable subpart.

(5) Reporting. Submit the reports required in the applicable subpart. Submit the records of the annual Method 21 screening required in paragraph (h)(7) of this section to the Administrator via e-mail to *CCG-AWP@EPA.GOV*.

[51 FR 2701, Jan. 21, 1986, as amended at 63 FR 24444, May 4, 1998; 65 FR 61752, Oct. 17, 2000; 73 FR 78209, Dec. 22, 2008]

§ 60.19 General notification and reporting requirements.

(a) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word "calendar" is absent, unless otherwise specified in an applicable requirement.

(b) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be postmarked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the postmark provided by the U.S. Postal Service, or alternative means of delivery, including the use of electronic media, agreed to by the permitting authority, is acceptable.

(c) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under this part, the owner or operator may change the dates by which periodic reports under this part shall be submitted (without changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in this part. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) If an owner or operator supervises one or more stationary sources affected by standards set under this part and standards set under part 61, part 63, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State with an approved permit program) a common schedule on which periodic reports required by each applicable standard shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the stationary source is required to be in compliance with the applicable subpart in this part, or 1 year after the stationary source is required to be in compliance with the applicable 40 CFR part 61 or part 63 of this chapter standard, whichever is latest. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(f)

(1)

(i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of this part.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

[59 FR 12428, Mar. 16, 1994, as amended at 64 FR 7463, Feb. 12, 1998]

Table 1 to Subpart A of Part 60—Detection Sensitivity Levels (grams per hour)

Monitoring frequency per subpart[a]	Detection sensitivity level
Bi-Monthly	60
Semi-Quarterly	85
Monthly	100

[a] When this alternative work practice is used to identify leaking equipment, the owner or operator must choose one of the monitoring frequencies listed in this table in lieu of the monitoring frequency specified in the applicable subpart. Bi-monthly means every other month. Semi-quarterly means twice per quarter. Monthly means once per month.

[73 FR 78211, Dec. 22, 2008]

2008); IBR approved for §§ 60.41b; 60.41c; 60.5580; 60.5580a.

* * * * *

(206) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, (Approved July 15, 2011), IBR approved for §§ 60.41b, 60.41c, 60.5580, and 60.5580a.

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(212) ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, (Approved August 1, 2010), IBR approved for §§ 60.41b, 60.41c, 60.5580, and 60.5580a.

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(i) Association of Official Analytical Chemists, 1111 North 19th Street, Suite 210, Arlington, VA 22209; phone: (301) 927–7077; website: *https://www.aoac.org/*.

* * * * *

(j) CSA Group (CSA) (formerly Canadian Standards Association), 178 Rexdale Boulevard, Toronto, Ontario, Canada; phone: (800) 463–6727; website: *https://shop.csa.ca*.

(1) CSA B415.1–10, Performance Testing of Solid-fuel-burning Heating Appliances, (March 2010), IBR approved for §§ 60.534; 60.5476.

(2) [Reserved]

* * * * *

(l) European Standards (EN), European Committee for Standardization, Management Centre, Avenue Marnix 17, B–1000 Brussels, Belgium; phone: + 32 2 550 08 11; website: *https://www.en-standard.eu*.

(1) DIN EN 303–5:2012E (EN 303–5), Heating boilers—Part 5: Heating boilers for solid fuels, manually and automatically stoked, nominal heat output of up to 500 kW—Terminology, requirements, testing and marking, (October 2012), IBR approved for § 60.5476.

(2) [Reserved]

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(m) GPA Midstream Association, 6060 American Plaza, Suite 700, Tulsa, OK 74135; phone: (918) 493–3872; website: *www.gpamidstream.org*.

* * * * *

(n) International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland; phone: + 41 22 749 01 11; website: *www.iso.org*.

(1) ISO 8178–4: 1996(E), Reciprocating Internal Combustion Engines—Exhaust Emission Measurement—part 4: Test Cycles for Different Engine Applications, IBR approved for § 60.4241(b).

(2) ISO 2314:2009(E), Gas turbines–Acceptance tests, Third edition (December 15, 2009), IBR approved for §§ 60.5580; 60.5580a.

(3) ISO 8316: Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank (1987–10–01)—First Edition, IBR approved for § 60.107a(d).

(4) ISO 10715:1997(E), Natural gas—Sampling guidelines, (First Edition, June 1, 1997), IBR approved for § 60.4415(a).

(o) National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, Virginia 22161.

* * * * *

(q) Pacific Lumber Inspection Bureau (formerly West Coast Lumber Inspection Bureau), 1010 South 336th Street #210, Federal Way, WA 98003; phone: (253) 835.3344; website: *www.plib.org*.

* * * * *

(r) Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Suite 115, Peachtree Corners, GA 30092; phone (800) 332–8686; website: *www.tappi.org*.

* * * * *

Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

■ 3. Section 60.5508 is revised to read as follows:

§ 60.5508 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit or an integrated gasification combined cycle (IGCC) facility that commences construction after January 8, 2014, commences reconstruction after June 18, 2014, or commences modification after January 8, 2014, but on or before May 23, 2023. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction after January 8, 2014, but on or before May 23, 2023, or commences reconstruction after June 18, 2014, but on or before May 23, 2023. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

■ 4. Section 60.5509 is revised to read as follows:

§ 60.5509 What are my general requirements for complying with this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit or IGCC that commenced construction after January 8, 2014, or commenced modification or reconstruction after June 18, 2014, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any stationary combustion turbine that commenced construction after January 8, 2014, but on or before May 23, 2023, or commenced reconstruction after June 18, 2014, but on or before May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (10) of this section.

(1) Your EGU is a steam generating unit or IGCC whose annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating

of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this paragraph (b)(7) continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU is a stationary combustion turbine that is not capable of combusting natural gas (*e.g.,* not connected to a natural gas pipeline).

(9) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

(10) Your EGU is subject to subpart TTTTa of this part.

■ 5. Section 60.5520 is revised to read as follows:

§ 60.5520 What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in table 1 or 2 to this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross or net energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross or net energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term ''gross or net energy output'' is used, the term that applies to you is ''gross energy output.''

(c) As an alternate to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term ''gross or net energy output'' is used, the term that applies to you is ''net energy output.'' Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in table 2 to this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in table 2 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less (*e.g.,* non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

■ 6. Section 60.5525 is revised to read as follows:

§ 60.5525 What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See table 1 or 2 to this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas ($HTIP_{ng}$) and the total heat input from all other fuels combined ($HTIP_o$) using one of the methods under § 60.5535(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

Equation 1 to Paragraph (a)(2)

$$CO_2 \text{ emissions standard } = \frac{(50 \text{ x } HTIP_{ng}) + (69 \text{ x } HTIP_O)}{HTIP_{ng} + HTIP_O}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

$HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas.

$HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu).

69 = allowable emission rate in kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu).

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.,* no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in table 1 or 2 to this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in 40 CFR 72.2) on or after October 23, 2015, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555(c)(3)(ii)(A), for units that are not in the Acid Rain Program.

(2) For an affected EGU that has commenced commercial operation (as defined in 40 CFR 72.2) prior to October 23, 2015:

(i) If the date on which emissions reporting is required to begin under 40 CFR 75.64(a) has passed prior to October 23, 2015, emissions reporting shall begin according to § 60.5555(c)(3)(i) (for Acid Rain program units), or according to § 60.5555(c)(3)(ii)(B) (for units that are not subject to the Acid Rain Program). The first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which the rule becomes effective; or

(ii) If the date on which emissions reporting is required to begin under 40 CFR 75.64(a) occurs on or after October 23, 2015, then the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under § 60.5555(c)(3)(ii)(A).

(3) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under § 60.5555(c)(3)(iii).

(4) Electric sales by your affected facility generated when it operated during a system emergency as defined in § 60.5580 are excluded for applicability with the base load standard if you can sufficiently provide the documentation listed in § 60.5560(i).

■ 7. Section 60.5535 is amended by revising paragraphs (a), (b), (c)(3), (d)(1), (e), and (f) to read as follows:

§ 60.5535 How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under § 60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555(d) and (e)).

(b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected EGU that combusts coal you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.,* carbon capture and storage), you may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, you may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part 75.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR part 75 to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with 40 CFR part 75. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for ‘‘valid operating hours’’, as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from equation F–11 in appendix F to 40

CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to part 75 (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 907.2 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(c) * * *

(3) For each ''valid operating hour'' (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Then, multiply the result by 907.2 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

* * * * *

(d) * * *

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.,* lb of CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20–2010 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.,* hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

* * * * *

(e) Consistent with § 60.5520, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross energy output. The Administrator may approve such alternate methods for apportioning the gross energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§ 60.13(g) and 60.5520, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in table 1 or 2 to this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as ''stack operating hours'' (as defined in 40 CFR 72.2). If you attain compliance with the applicable emissions standard in § 60.5520 at the common stack, each affected EGU sharing the stack is in compliance.

(2) As an alternative, or if the EGUs are subject to different emission standards in table 1 or 2 to this subpart, you must either:

(i) Monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or

(ii) Apportion the CO_2 mass emissions based on the unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

* * * * *

■ 8. Section 60.5540 is revised to read as follows:

§ 60.5540 How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in table 1 or 2 to this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (8) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.,* either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under § 60.5535(b) or (c), as applicable, and either the generating load data from § 60.5535(d)(1) for output-based calculations or the heat input data from § 60.5535(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.,* blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only ''valid operating hours'' in the compliance period, *i.e.,* operating hours for which:

(i) ''Valid data'' (as defined in § 60.5580) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (*Note:* For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of 40 CFR 75 are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535 for all of the valid operating hours in the compliance period.

(5) For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(5)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with § 60.5520) value reported under 40 CFR part 75 to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to paragraph (a)(5)(i)

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW} - (Pe)_{A}}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}] \quad \text{(Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

Equation 2 to Paragraph (a)(5)(ii)

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \quad \text{(Eq. 3)}$$

Where:

Q_m = Measured useful thermal output flow in kg (lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) Sources complying with energy output-based standards must calculate the basis (*i.e.,* denominator) of their actual 12-operating month emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual 12-operating month emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520 if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section.

Round off the result to two significant figures.

(b) In accordance with § 60.5520, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (8) of this section and must be less than or equal to the applicable CO_2 emissions standard in table 1 or 2 to this subpart, or the emissions standard calculated in accordance with § 60.5525(a)(2).

■ 9. Section 60.5555 is amended by revising paragraphs (a)(2)(iv) and (v), (f), and (g) to read as follows.

§ 60.5555 What reports must I submit and when?

(a) * * *

(2) * * *

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1) of this section (*i.e.,* the total number of valid operating hours (as defined in § 60.5540(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520, the CO_2 emissions standard (as identified in table 1 or 2 to this subpart) with which your affected EGU must comply; and

* * * * *

(f) If your affected EGU captures CO_2 to meet the applicable emissions standard, you must report in accordance with the requirements of 40 CFR part 98, subpart PP, and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

■ 10. Section 60.5560 is amended by adding paragraphs (h) and (i) to read as follows:

§ 60.5560 What records must I maintain?

* * * * *

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

(i) You must keep the records listed in paragraphs (i)(1) through (3) of this section to demonstrate that your affected facility operated during a system emergency.

(1) Documentation that the system emergency to which the affected EGU was responding was in effect from the entity issuing the alert, and documentation of the exact duration of the event;

(2) Documentation from the entity issuing the alert that the system emergency included the affected source/region where the affected facility was located, and

(3) Documentation that the affected facility was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/Regional Transmission Organization.

■ 11. Section 60.5580 is amended by:

■ a. Revising the definitions for ''Annual capacity factor'', and ''Base load rating'';

■ b. Revising and republishing the definition for ''Coal''; and

■ c. Revising the definitions for ''Combined cycle unit'', ''Combined head and power unit or CHP unit'', ''Design efficiency'', ''Distillate oil'', ''ISO conditions'', ''Net electric sales'', and ''System emergency''.

The revisions and republications read as follows:

§ 60.5580 What definitions apply to this subpart?

* * * * *

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.,* solar thermal) are not included when calculating the annual capacity factor.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.,* solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM International in ASTM D388–99R04 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as ''cogeneration'') means an electric generating unit that simultaneously produces both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22–2014, ASME PTC 46–1996, ISO 2314:2009(E) (all incorporated by reference, see § 60.17), or an alternative approved by the Administrator.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined in ASTM D396–98 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined in ASTM D975–08a (incorporated by reference, see § 60.17); kerosene, as defined in ASTM D3699–08 (incorporated by reference, see § 60.17); biodiesel as defined in ASTM D6751–11b (incorporated by reference, see § 60.17); or biodiesel blends as defined in ASTM D7467–10 (incorporated by reference, see § 60.17).

* * * * *

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

* * * * *

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating month basis, the gross electric sales to the utility power distribution system minus purchased power of the thermal host facility or facilities.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales during a system emergency are not included when calculating net-electric sales.

* * * * *

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP–011–2 or its successor.

* * * * *

■ 12. Table 1 to subpart TTTT is revised to read as follows:

Table 1 to Subpart TTTT of Part 60—CO_2 Emission Standards for Affected Steam Generating Units and Integrated Gasification Combined Cycle Facilities That Commenced Construction After January 8, 2014, and Reconstruction or Modification After June 18, 2014

[*Note:* Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed steam generating unit or integrated gasification combined cycle (IGCC).	640 kg CO_2/MWh of gross energy output (1,400 lb CO_2/MWh-gross).
Reconstructed steam generating unit or IGCC that has base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less.	910 kg CO_2/MWh of gross energy output (2,000 lb CO_2/MWh-gross).
Reconstructed steam generating unit or IGCC that has a base load rating greater than 2,100 GJ/h (2,000 MMBtu/h).	820 kg CO_2/MWh of gross energy output (1,800 lb CO_2/MWh-gross).
Modified steam generating unit or IGCC	A unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no lower than: (1) 820 kg CO_2/MWh of gross energy output (1,800 lb CO_2/MWh-gross) for units with a base load rating greater than 2,100 GJ/h (2,000 MMBtu/h); or (2) 910 kg CO_2/MWh of gross energy output (2,000 lb CO_2/MWh-gross) for units with a base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less.

■ 13. Table 2 to subpart TTTT is revised to read as follows:

Table 2 to Subpart TTTT of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction After January 8, 2014, and Reconstruction After June 18, 2014 (Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[*Note:* Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that supplies more than its design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis.	450 kg CO_2/MWh (1,000 lb CO_2/MWh) of gross energy output; or 470 kg CO_2/MWh (1,030 lb CO_2/MWh) of net energy output.

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis].	50 kg CO_2/GJ (120 lb CO_2/MMBtu) of heat input.
Newly constructed and reconstructed stationary combustion turbine that combusts 90% or less natural gas on a heat input basis on a 12-operating-month rolling average basis.	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525.

■ 14. Table 3 to subpart TTTT is revised to read as follows:

Table 3 to Subpart TTTT of Part 60—Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTT

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification.	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	No.	
§ 60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods
§ 60.8(c)–(f)	Conducting performance tests	No.	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13 (a)–(h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§ 60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements
§ 60.14	Modification	Yes (steam generating units and IGCC facilities). No (stationary combustion turbines).	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements.	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.

■ 15. Add subpart TTTTa to read as follows:

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Applicability

§ 60.5508a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a coal-fired steam generating unit or integrated gasification combined cycle facility (IGCC) that commences modification after May 23, 2023. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction or reconstruction after May 23, 2023. An affected coal-fired steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

§ 60.5509a Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit or IGCC that combusts coal and that commences modification after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (8) of this section.

(1) Your EGU is a steam generating unit or IGCC whose annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

Emission Standards

§ 60.5515a Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) PSD and Title V thresholds for greenhouse gases.

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the ‘‘pollutant that is subject to the standard promulgated under section 111 of the Act’’ shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the ‘‘pollutant that is subject to the standard promulgated under section 111 of the Act’’ shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the ‘‘pollutant that is subject to any standard promulgated under section 111 of the Act’’ shall be considered to be the pollutant that otherwise is ‘‘subject to regulation’’ as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the ‘‘pollutant that is subject to any standard promulgated under section 111 of the Act’’ shall be considered to be the pollutant that otherwise is ‘‘subject to regulation’’ as defined in 40 CFR 71.2.

§ 60.5520a What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in table 1 to this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross or net energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross or net energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term ''gross or net energy output'' is used, the term that applies to you is ''gross energy output.''

(c) As an alternative to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term ''gross or net energy output'' is used, the term that applies to you is ''net energy output.'' Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in table 1 to this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in table 1 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel, kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less (*e.g.,* non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

§ 60.5525a What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See table 1 to this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520a(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas (HTIPng) and the total heat input from all other fuels combined (HTIPo) using one of the methods under § 60.5535a(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

Equation 1 to Paragraph (a)(2)

$$CO_2\ emissions\ standard\ = \frac{\left(50\ \mathrm{x}\ HTIP_{ng}\right) + (69\ \mathrm{x}\ HTIP_O)}{HTIP_{ng} + HTIP_O}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

$HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas.

$HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in lb kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu).

69 = allowable emission rate in lb kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu).

(3) Owners/operators of a base load combustion turbine with a base load rating of less than 2,110 GJ/h (2,000 MMBtu/h) and/or an intermediate or base load combustion turbine burning fuels other than natural gas may elect to determine a site-specific emissions rate using one of the following equations. Combustion turbines co-firing hydrogen are not required to use the fuel adjustment parameter.

(i) For base load combustion turbines:

Equation 2 to Paragraph (a)(3)(i)

$$CO_2\ emissions\ standard\ = \left[BLER_L + \frac{BLER_S - BLER_L}{\mathrm{BLR}_L - \mathrm{BLR}_S} * (\mathrm{BLR}_L - BLR_A)\right] * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

$BLER_L$ = Base load emissions standard for natural gas-fired combustion turbines with base load ratings greater than 2,110 GJ/h (2,000 MMBtu/h). 360 kg CO_2/MWh-gross (800 lb CO_2/MWh-gross) or 370 kg CO_2/MWh-net (820 lb CO_2/MWh-net); 43 kg CO_2/MWh-gross (100 lb CO_2/MWh-gross) or 42 kg CO_2/MWh-net (97 lb CO_2/MWh-net); as applicable

$BLER_S$ = Base load emissions standard for natural gas-fired combustion turbines with a base load rating of 260 GJ/h (250 MMBtu/h). 410 kg CO_2/MWh-gross (900 lb CO_2/MWh-gross) or 420 kg CO_2/MWh-net (920 lb CO_2/MWh-net); 49 kg CO_2/MWh-gross (108 lb CO_2/MWh-gross) or 50 kg CO_2/MWh-net (110 lb CO_2/MWh-net); as applicable

BLR_L = Minimum base load rating of large combustion turbines 2,110 GJ/h (2,000 MMBtu/h)

BLR_S = Base load rating of smallest combustion turbine 260 GJ/h (250 MMBtu/h)

BLR_A = Base load rating of the actual combustion turbine in GJ/h (or MMBtu/h)

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(ii) For intermediate load combustion turbines:

Equation 3 to Paragraph (a)(3)(ii)

$$CO_2\ emissions\ standard\ = \mathrm{ILER} * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

ILER = Intermediate load emissions rate for natural gas-fired combustion turbines. 520 kg/MWh-gross (1,150 lb CO_2/MWh-gross) or 530 kg CO_2/MWh-net (1,160 lb CO_2/MWh-net) or 450 kg/MWh-gross (1,100 lb CO_2/MWh-gross) or 460 kg CO_2/MWh-net (1,110 lb CO_2/MWh-net) as applicable

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.,* no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in table 1 to this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in 40 CFR 72.2), the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555a(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555a(c)(3)(ii), for units that are not in the Acid Rain Program.

(2) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under § 60.5555a(c)(3)(iii).

(3) Emissions of CO_2 emitted by your affected facility and the output of the affected facility generated when it operated during a system emergency as defined in § 60.5580a are excluded for both applicability and compliance with the relevant standards of performance if you can sufficiently provide the documentation listed in § 60.5560a(i). The relevant standard of performance for affected EGUs that operate during a system emergency depends on the subcategory, as described in paragraphs (c)(3)(i) and (ii) of this section.

(i) For intermediate and base load combustion turbines that operate during a system emergency, you comply with the standard for low load combustion turbines specified in table 1 to this subpart.

(ii) For modified steam generating units, you must not discharge from the affected EGU any gases that contain CO_2 in excess of 230 lb CO_2/MMBtu.

Monitoring and Compliance Determination Procedures

§ 60.5535a How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520a(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555a(d) and (e)).

(b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected EGU that combusts coal you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.,* carbon capture and storage), you may use data from a certified oxygen

(O2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, you may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part 75.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR part 75 to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with 40 CFR part 75. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for ''valid operating hours'', as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F–11 in appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 907.2 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in § 60.5520a(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to 40 CFR part 75 to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G–4 in appendix G to 40 CFR part 75 to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (Fc) using Equation F–7b in section 3.3.6 of appendix F to 40 CFR part 75, and you may use these Fc values in the emissions calculations instead of using the default Fc values in the Equation G–4 nomenclature.

(3) For each ''valid operating hour'' (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Then, multiply the result by 907.2 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under § 60.107a(d) and convert this heat input to CO_2 emissions using Equation G–4 in appendix G to 40 CFR part 75.

(ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under 40 CFR 98.33(a)(3).

(d) Consistent with § 60.5520a, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.,* lb CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20–2010 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580a, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.,* hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.,* lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under § 60.5520a(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to 40 CFR part 75;

(ii) The procedures for monitoring heat input under § 60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under 40 CFR 98.33(a)(3), you may convert your CO_2 emissions to heat input using the appropriate emission factor in table C–1 of 40 CFR part 98. If your fuel is not listed in table C–1, you must determine a fuel-specific carbon-based F-factor (Fc) in accordance with section 12.3.2 of EPA Method 19 of appendix A–7 to this part, and you must convert your CO_2 emissions to heat input using Equation G–4 in appendix G to 40 CFR part 75.

(e) Consistent with § 60.5520a, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross or net energy output. The Administrator may approve such alternate methods for apportioning the gross or net energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§ 60.13(g) and 60.5520a, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in table 1 to this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as ''stack operating hours'' (as defined in 40 CFR 72.2). If you attain compliance with the applicable emissions standard in § 60.5520a at the common stack, each affected EGU sharing the stack is in compliance; or

(2) As an alternative to the requirements in paragraph (f)(1) of this section, or if the EGUs are subject to different emission standards in table 1 to this subpart, you must either:

(i) Monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or

(ii) Apportion the CO_2 mass emissions based on the unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(g) In accordance with §§ 60.13(g) and 60.5520a if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the ''stack operating time'' (as defined in 40 CFR 72.2) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in table 1 or 2 to this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§ 60.5540a How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520a, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520a(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in table 1 to this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (8) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.,* either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under § 60.5535a(b) or (c), as applicable, and either the generating load data from § 60.5535a(d)(1) for output-based calculations or the heat input data from § 60.5535a(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.,* blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only ''valid operating hours'' in the compliance period, *i.e.,* operating hours for which:

(i) ''Valid data'' (as defined in § 60.5580a) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (Note: For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535a for all of the valid operating hours in the compliance period.

(5) For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(5)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with § 60.5520a) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to Paragraph (a)(5)(i)

Equation 1 to Paragraph (a)(5)(i)

$$P_{gross/net} = \frac{(Pe)_{ST}+(Pe)_{CT}+(Pe)_{IE}-(Pe)_{FW}-(Pe)_{A}}{TDF} + [\ (Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}\ ] \text{ (Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520a, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540a(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate (Pt)PS using the following equation:

Equation 2 to Paragraph (a)(5)(ii)

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \text{ (Eq. 3)}$$

Where:

Q_m = Measured useful thermal output flow in kg (lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) Sources complying with energy output-based standards must calculate the basis (*i.e.,* denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520a if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(8) You may exclude CO_2 mass emissions and output generated from your affected EGU from your calculations for hours during which the affected EGU operated during a system emergency, as defined in § 60.5580a, if you can provide the information listed in § 60.5560a(i). While operating during a system emergency, your compliance determination depends on your subcategory or unit type, as listed in paragraphs (a)(8)(i) through (ii) of this section.

(i) For affected EGUs in the intermediate or base load subcategory, your CO_2 emission standard while operating during a system emergency is the applicable emission standard for low load combustion turbines.

(ii) For affected modified steam generating units, your CO_2 emission standard while operating during a system emergency is 230 lb CO_2/MMBtu.

(b) In accordance with § 60.5520a, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (8) of this section and must be less than or equal to the applicable CO_2 emissions standard in table 1 to this subpart, or the emissions standard calculated in accordance with § 60.5525a(a)(2).

(c) If you are the owner or operator of a new or reconstructed stationary combustion turbine operating in the base load subcategory, are installing add-on controls, and are unable to comply with the applicable Phase 2 CO_2 emission standard specified in table 1 to this subpart due to circumstances beyond your control, you may request a compliance date extension of no longer than one year beyond the effective date of January 1, 2032, and may only receive an extension once. The extension request must contain a demonstration of necessity that includes the following:

(1) A demonstration that your affected EGU cannot meet its compliance date due to circumstances beyond your control and you have taken all steps reasonably possible to install the controls necessary for compliance by the effective date up to the point of the delay. The demonstration shall:

(i) Identify each affected unit for which you are seeking the compliance extension;

(ii) Identify and describe the controls to be installed at each affected unit to comply with the applicable CO_2 emission standard in table 1 to this subpart;

(iii) Describe and demonstrate all progress towards installing the controls and that you have acted consistently with achieving timely compliance, including;

(A) Any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable;

(B) Any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permit authority identifying its anticipated timeframe for issuance of such permit(s).

(iv) Identify the circumstances that are entirely beyond your control and that necessitate additional time to install the identified controls. This may include:

(A) Information gathered from control technology vendors or engineering firms demonstrating that the necessary controls cannot be installed or started up by the applicable compliance date listed in table 1 to this subpart;

(B) Documentation of any permit delays; or

(C) Documentation of delays in construction or permitting of infrastructure (*e.g.,* CO_2 pipelines) that is necessary for implementation of the control technology;

(v) Identify a proposed compliance date no later than one year after the applicable compliance date listed in table 1 to this subpart.

(2) The Administrator is charged with approving or disapproving a compliance date extension request based on his or her written determination that your affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation according to paragraph (c)(1) of this section. The following must be included:

(i) All documentation required as part of this extension must be submitted by you to the Administrator no later than 6 months prior to the applicable effective date for your affected EGU.

(ii) You must notify the Administrator of the compliance date extension request at the time of the submission of the request.

Notification, Reports, and Records

§ 60.5550a What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see table 3 to this subpart).

(b) You must prepare and submit notifications specified in 40 CFR 75.61, as applicable, to your affected EGUs.

§ 60.5555a What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by § 60.5525a to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in § 60.5540a. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1) of this section (*i.e.,* the total number of valid operating hours (as defined in § 60.5540a(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520a, the CO_2 emissions standard (as identified in table 1 or 2 to this subpart) with which your affected EGU must comply; and

(vi) Consistent with § 60.5520a, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with § 60.5520a, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit

reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with 40 CFR 75.64(a), *i.e.,* beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in 40 CFR 75.20(a)(3); or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in 40 CFR 72.2).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after the date on which reporting is required to begin under 40 CFR 75.64(a), if that date occurs on or after May 23, 2023.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with 40 CFR 75.4(j), 40 CFR 75.37(b), or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not ''valid operating hours'' (as defined in § 60.5540(a)(1)), and shall not be used in the compliance determinations under § 60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under 40 CFR 72.20; or

(2) The person appointed as the Alternate Designated Representative (ADR) under 40 CFR 72.22; or

(3) A person (or persons) authorized by the DR or ADR under 40 CFR 72.26 to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission standard, you must report in accordance with the requirements of 40 CFR part 98, subpart PP, and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured CO_2 to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§ 60.5560a What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in § 60.7(b) and (f).

(b)(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under 40 CFR 75.53(g) and (h);

(ii) Operating parameter records under 40 CFR 75.57(b)(1) through (4);

(iii) The records under 40 CFR 75.57(c)(2), for stack gas volumetric flow rate;

(iv) The records under 40 CFR 75.57(c)(3) for continuous moisture monitoring systems;

(v) The records under 40 CFR 75.57(e)(1), except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O2 monitors used to calculate CO_2 concentration;

(vi) The records under 40 CFR 75.58(c)(1), specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under 40 CFR 75.58(c)(4), specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under 40 CFR 75.59(e).

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with § 60.5520a, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in table 1 or 2 to this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

(i) You must keep the records listed in paragraphs (i)(1) through (3) of this section to demonstrate that your affected facility operated during a system emergency.

(1) Documentation that the system emergency to which the affected EGU was responding was in effect from the entity issuing the alert and documentation of the exact duration of the system emergency;

(2) Documentation from the entity issuing the alert that the system emergency included the affected source/region where the affected facility was located; and

(3) Documentation that the affected facility was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/Regional Transmission Organization.

§ 60.5565a In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 5 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

Other Requirements and Information

§ 60.5570a What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§ 60.1 through 60.19, listed in table 3 to this subpart, do not apply to your affected EGU.

§ 60.5575a Who implements and enforces this subpart?

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

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or Tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or Tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

§ 60.5580a What definitions apply to this subpart?

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

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.,* solar thermal) are not included when calculating the annual capacity factor.

Base load combustion turbine means a stationary combustion turbine that supplies more than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.,* solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite in ASTM D388–99R04 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired Electric Generating Unit means a steam generating unit or integrated gasification combined cycle unit that combusts coal on or after the date of modification or at any point after December 31, 2029.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as ''cogeneration'') means an electric generating unit that simultaneously produces both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a higher heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22–2014, ASME PTC 46–1996, ISO 2314:2009 (E) (all incorporated by reference, see § 60.17), or an alternative approved by the Administrator. When determining the design efficiency, the output of integrated equipment and energy storage are included.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined in ASTM D396–98 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined in ASTM D975–08a (incorporated by reference, see § 60.17); kerosene, as defined in ASTM D3699–08 (incorporated by reference, see § 60.17); biodiesel as defined in ASTM D6751–11b (incorporated by reference, see § 60.17); or biodiesel blends as defined in ASTM D7467–10 (incorporated by reference, see § 60.17).

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (*i.e.,* meets the applicability criteria).

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas, plus any integrated equipment that provides electricity or useful thermal output to the affected EGU or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

Intermediate load combustion turbine means a stationary combustion turbine that supplies more than 20 percent but less than or equal to 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Low load combustion turbine means a stationary combustion turbine that supplies 20 percent or less of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating month basis, the gross electric sales to the utility power distribution system minus the applicable percentage of purchased power of the thermal host facility or facilities. The applicable percentage of purchase power for CHP facilities is determined based on the percentage of the total thermal load of the host facility supplied to the host facility by the CHP facility. For example, if a CHP facility serves 50 percent of a thermal host's thermal demand, the owner/operator of the CHP facility would subtract 50 percent of the thermal host's electric purchased power when calculating net-electric sales.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales during a system emergency are not included when calculating net-electric sales.

Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means the base load rating design efficiency at the maximum electric production rate (*e.g.,* CHP units with condensing steam turbines will operate at maximum electric production) multiplied by the base load rating (expressed in MMBtu/

h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.,* a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, (*e.g.,* onsite photovoltaics), integrated energy storage (*e.g.,* onsite batteries), heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment.

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP–011–2 or its successor.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in 40 CFR 75.20 and appendix A to 40 CFR part 75 must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to 40 CFR part 75 must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to 40 CFR part 75. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to 40 CFR part 75 must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to 40 CFR part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to 40 CFR part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in table 1 to this subpart.

TABLE 1 TO SUBPART TTTTA OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STATIONARY COMBUSTION TURBINES THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 23, 2023 (GROSS OR NET ENERGY OUTPUT-BASED STANDARDS APPLICABLE AS APPROVED BY THE ADMINISTRATOR)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU category	CO_2 emission standard
Base load combustion turbines	For 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a. For 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Intermediate load combustion turbines	530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 700 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Low load combustion turbines	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525a.

TABLE 2 TO SUBPART TTTTA OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STEAM GENERATING UNITS OR IGCC THAT COMMENCED MODIFICATION AFTER MAY 23, 2023

Affected EGU	CO_2 Emission standard
Modified coal-fired steam generating unit.	A unit-specific emissions standard determined by an 88.4 percent reduction in the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification).

TABLE 3 TO SUBPART TTTTA OF PART 60—APPLICABILITY OF SUBPART A OF PART 60 (GENERAL PROVISIONS) TO SUBPART TTTTA

General provisions citation	Subject of citation	Applies to subpart TTTTa	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580a.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification.	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping.	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	No..	
§ 60.8(b)	Performance test method alternatives.	Yes	Administrator can approve alternate methods.
§ 60.8(c)–(f)	Conducting performance tests.	No..	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No..	
§ 60.12	Circumvention	Yes.	
§ 60.13 (a)–(h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§ 60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements.
§ 60.14	Modification	Yes (steam generating units and IGCC facilities) No (stationary combustion turbines)..	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No..	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements.	No..	
§ 60.19	General notification and reporting requirements.	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.

Appendix B to Part 60 – Performance Specifications

PS-19 Appendix B Preparation and Certification of Ethylene Oxide Gas Standards

1.0 Scope and Application

1.1 This appendix (appendix PS-19B) to Performance Specification 19 (PS-19) describes the procedure and performance criteria for the preparation and certification of EtO Gas Manufacturer Primary Standards (GMPS) and Gas Manufacturer Alternative Certified Standards (GMACS). These procedures are not specific to ethylene oxide and could be transferable to the preparation of gas standards for other pollutants regulated under 40 CFR parts 59, 60, 61, 63, and 65.

2.0 Summary of the Appendix

EPA requires the use of EPA Protocol gas standards for emissions monitoring. These gases are established following the EPA Traceability Protocol for Assay and Certification of Gaseous Standards, May 2012 (EPA 600/R-12/531) otherwise referred in this appendix PS-19B as the EPA Traceability Protocol. The EPA Traceability Protocol requires the use of certified reference gas standards directly traceable to National Institute of Standards and Technology (NIST) or other recognized national metrology institute (NMI) reference gas standards. A NIST certified value is a value for which NIST has the highest confidence in that all known or suspected sources of bias and imprecision have been accounted for. Without NIST or other NMI reference gas standards, the necessary EPA Protocol gas standards cannot be prepared. An alternative approach is needed to establish a gas standard functionally equivalent to the EPA Protocol gas standard when NIST or NMI reference gas standard are not available. This appendix PS-19B is intended to provide procedures and performance criteria for the establishment of Gas Manufacturer Alternative Certified Standards (GMACS), the functional equivalent of EPA Protocol gas standards. GMACS and Gas Manufacturer Primary Standards (GMPS), the functional equivalent of the NIST or NMI reference gas standards. The GMPS are the reference gases used to establish the certified concentrations of the GMACs. The GMPS are established using a dual certification approach where the gravimetrically prepared reference value is confirmed using an independent measurement approach traceable to the International System of Units (SI) and references materials or devices.

2.1 This appendix PS-19B is intended to be performance-based and allow specialty gas manufacturers (SGM) flexibility in the preparation and certification of GMPS and GMACS.

2.2 This appendix PS-19B is not intended to be a replacement for the EPA Protocol gases established according to the EPA Traceability Protocol when calibration gases that meet EPA Traceability Protocol requirements are available. When NIST or other recognized NMI reference gas standards are manufactured and readily available, those gases must be used.

2.3 This appendix PS-19B is reliant on the procedures included the EPA Traceability Protocol for Assay and Certification of Gaseous Standards, May 2012 (EPA 600/R-12/531). Users of this appendix PS-19B for the preparation of GMPS and GMACS must be proficient with the preparation protocol cylinders using this standard.

Note:

This appendix PS-19B does not require the user to participate in any protocol gas verification program.

2.4 Any alternatives to the procedures in this appendix PS-19B are subject to Administrator review under the alternative test method the authority to approve alternatives or changes to test methods specified in the General Provisions to 40 CFR parts 60, 61, and 63 (§§ 60.8(b)(2), 61.13(h)(1)(ii), and 63.7(e)(2)(ii)). Requests for alternative to the procedures must be submitted to the agency according to Guideline Document 22 (*https://www.epa.gov/system/files/documents/2022-09/gd-022r5.pdf*).

3.0 Definitions

3.1 *Certification* means a set of procedures and performance criteria used by a SGM to prepare and certify a GMPS and/or GMACS for commercial sale.

3.2 *Certified Reference Material or CRM* means a material that has been certified or verified by either NIST or other NMI (*e.g.,* VSL, NPL) and may be used for traceability purposes.

3.3 *Dual Method Certification* means a process in which the gravimetric value is independently confirmed by a measured value.

3.4 *EPA Protocol Gas means* a calibration or reference gas required for emissions monitoring directly traceable to NIST or other accepted NMI reference gas standards, prepared following the EPA Traceability Protocol

3.5 *EPA Traceable Protocol for Assay and Calibration Gas Standards or commonly referred to as the "EPA Traceability Protocol"* means the document The protocol allows producers of these standards, users of gaseous standards, and other analytical laboratories to establish traceability of EPA Protocol Gases to gaseous reference standards produced by the National Institute of Standards and Technology (NIST).

3.6 *Gas Calibration Cylinder means* a refillable cylinder that meets the applicable DOT/TC specifications for high pressure cylinders. The cylinders shall be permanently stamped with a unique value.

3.7 *Gas Manufacturer Alternative Certified Standards or GMACS* means a gas that has been prepared according to this procedure and serves as a functional substitute for an EPA Protocol Gas where EPA Protocol gases are not available.

3.8 *Gas Manufacturer Intermediate Standard* means a gas reference standard made by a gas supplier and certified according to the U.S. EPA protocol rules for GMISs. For the purpose of this Appendix, GMISs may be assayed against a GMPS.

3.9 *Gas Manufacturer Primary Standards or GMPS* means a reference gas standard prepared and certified by the SGM that serves as a functional substitute for the reference gas standards established by, but not yet available from NIST or other accepted NMI and required by the EPA Traceability Protocol to produce EPA Protocol gases.

3.10 *Gravimetry* means the quantitative measurement of an analyte by weight.

3.11 *NIST* means the National Institute of Standards and Technology, located in Gaithersburg, Maryland.

3.12 *NIST Traceable Reference Material or NTRM* means is a reference material produced by a commercial supplier with a well-defined traceability linkage to NIST and named by NIST procedures, on a batch rather than individual basis. This linkage is established via criteria and protocols defined by NIST that are tailored to meet the needs of the metrological community to be served.

3.13 *Primary Reference Materials or PRM* means a mixture composition is verified against VSL's own primary standard gas mixtures to confirm the assigned value.

3.14 *Protocol Gas* means a calibration or reference gas required for emissions monitoring traceable to NIST or other accepted NMI, prepared following the EPA Traceability Protocol.

3.15 *Research Gas Mixture or RGMs* means a reference material produced by a commercial supplier certified by NIST on an individual basis, often using non routine procedures, are called Research Gas Mixtures (RGMs), and may be used for traceability purposes.

3.16 *Specialty Gas Manufacturer or SGM* means an organization that prepares and certified gas calibration gas mixtures.

3.17 *International System of Units or SI* means the standards for international measurement and are comprised of length (meter), time (second), amount of substance (mole), electric current (ampere), temperature (kelvin), luminous intensity (candela), and mass (kilogram).

3.18 *Standard Reference Material or SRM* means a material or substance issued by NIST that meets NIST-specific certification criteria and is issues with that with a certificate or certificate of analysis that reports the results of its characterizations and provides information regarding the appropriate use(s) of the material.

3.19 *Uncertainty* means the expression of the statistical dispersion of the values attributed to a measured quantity. For the purpose of this appendix, uncertainty is calculated using the root sum square of all uncertainty budget items associated with each procedure at k=2 (*i.e.,* approximately 95 confidence).

3.20 VSL means Van Swinden National Lab, located in Delft, Netherlands.

4.0 Interferences—Reserved

5.0 Safety

The procedures required under this appendix may involve hazardous materials, operations, and equipment. This procedure may not address all of the safety problems associated with these procedures. You as the facility or operator must establish appropriate safety and health practices and determine the applicable regulatory limitations prior to performing these procedures. You should consult instrument operation manuals, material safety data sheets, compressed gas safety requirements, and other Occupational Safety and Health Administration regulations for specific precautions to be taken.

6.0 Equipment and Supplies

This procedure is not prescriptive on the type of equipment or the supplies necessary for the preparation of GMPS and GMACS gaseous cylinder standards, however SGM must use the appropriate equipment and supplies necessary to meet the uncertainty requirements in this appendix.

7.0 Reagents and Standards—Reserved

8.0 Procedures.

The exact procedures used will depend on the gas manufacturer and the physical characteristics of the compound being prepared as a gaseous calibration standard. Any procedure is deemed appropriate so long as the criteria in section 8.1 for GMPS and section 8.2 for GMACS are met.

8.1 *Preparation and Certification of the GMPS.*

The GMPS certified value is established using the dual certification approach. A candidate GMPS cylinder is prepared gravimetrically, and its established reference value is confirmed by an independent measurement traceable to SI units as well as other appropriate reference materials. The level of agreement between the gravimetric reference value and the SI-based independent measurements along with the average value and associated, combined, expanded uncertainties serve to establish the certified reference value. If high purity reference material is not readily available for a gravimetric preparation, a user may petition the Administrator for an alternative method for preparation of a GMPS.

The procedures for the gravimetric preparation, stability evaluation, and independent verification of GMPS must meet the criteria in this section following the procedures in 8.1*(a)* through *(g)*.

(a) Raw Materials

(b) GMPS Cylinder Preparation/Creation

(c) GMPS Cylinder Independent Verification

(d) GMPS Cylinder Certification

(e) GMPS Cylinder Stability

(f) GMPS Cylinder Expiration Period

(g) GMPS Documentation

8.1.1 Raw Materials. Raw materials used in the production of GMPS must be of high quality (*e.g.,* 99+% purity recommended). Additionally, because raw material purity is the largest component of uncertainty in gas gravimetry, SGMs must substantiate the purity of the raw material prior to use, either via (1) a validated certificate of analysis for the actual lot number purchased provided by the raw material vendor, or (2) a purity assay conducted by the SGM on the actual raw material to be used. The uncertainty of the raw material (U_r) assay must be included as one of the components of the total combined uncertainty for the mixture.

8.1.2 GMPS Gravimetric Cylinder Preparation/Creation. The GMPS standards shall be based on a gravimetric preparation. The gravimetric preparation shall yield an expected concentration for the target component, and with the required statistical controls in place to calculate the uncertainty of that concentration.

8.1.2.1 The scale used to generate the gravimetric reference standard must be independently calibrated over the range of target masses with ASTM E617-13 Class-1 weights on no less than a yearly basis. For such certifications, a high accuracy mass comparator (electronic or pendulum-type scale) is employed as the "scale." The resolution of the scale should be sufficient to be able to calculate the overall uncertainty of any concentration derived from these steps.

8.1.2.1.1 The scale used for the gravimetric operation must be independently calibrated and traceable to NIST standards with a defined uncertainty (u_t).

8.1.2.1.2 The scale calibration must be checked before the start of each new weighing operation (*i.e.,* the day of) with a weight in the appropriate range that also meets ASTM E617-13 Class-1 requirements.

8.1.2.1.3 All material and equipment associated with the gravimetric analysis shall have or apply a procedure to estimate the uncertainty of the measurement, including but not limited to the balance(s) used (u_{ca}) standard weight (u_w).

8.1.2.1.4 The assay purity and associated material uncertainty (u_r) of the assay for each component raw material and the balance gas must be known. This purity deviation is factored into the uncertainty of the mass of each material blended into the mixture.

8.1.2.1.5 The procedures below are minimum requirements and do not speak to all of the details an SRM would do to ensure the preparation of a high-accuracy gravimetric candidate GMPS, (*e.g.,* controls for external factors that would influence scale reading accuracy buoyancy effects, moisture/dust adsorption on the cylinder surface, and errors caused by the location of the cylinder on the scale). The SGM should develop and follow and internal standard operation procedures (SOP) for the preparation of the candidate GMPS.

8.1.2.1.6 Record the Target cylinder identification number, blend date, and balance gas on the appropriate form (see figure B-1). Additionally, record the intended component(s) to be used in the preparation for this candidate GMPS, identifying the standard type, material name (*e.g.,* Ethylene Oxide), MW (g/mol), and purity (wt%).

8.1.2.1.7 Add the components to the candidate GMPS, recording the weight of each component added.

8.1.2.1.8 GMPS Gravimetric Uncertainty. Calculate and document the gravimetric concentration (GMPS-C_g) for each component of the candidate GMPS. You must also document the combined uncertainty, expressed as the root sum of the uncertainty budget items identified, for the candidate GMPS value (GMPS-C_{gu}). Gravimetric preparation uncertainty budget items include:

(a) The purity of the raw material and the balance gas;

(b) The measured accuracy of the (electronic) balance including consideration the uncertainty of the calibration weights, the calibration uncertainty, and its linearity;

(c) The repeatability of the balance readings including errors caused by the location of the cylinder on the balance;

(d) Balance Buoyancy effects;

(e) Effects of moisture adsorption and dust on the outer surface of the cylinder;

(f) Cylinder dilutions, if any, used to prepare target concentrations, including propagated uncertainties.

8.1.3 *GMPS Independent Verification.* The certification of the candidate GMPS is based on independent measurements verifying the reference concentration of the gravimetrically prepared GMPS candidate. The independent verification must be based on a measurement approach traceable to the SI and may include the use of intrinsic NIST or accepted NMI reference materials to establish said traceability. Candidate independent verification measurement approaches include classical chemistry, spectroscopic approaches, as well as other instrumental approaches as long as adequate and appropriate SI traceability can be incorporated. The approach must be performed using NIST (or equivalent) traceable calibrations materials and using procedures that would allow the user to determine the overall uncertainty of the measurement. In some instances, a component may not be suitable to analysis using a classical approach, in those instances alternative approaches may be used do long as they (1) yield a concentration for the target com, (2) have a calculated uncertainty, (3) have traceability to the SI, and (4) documented conformity to the general metrological principles for primary methods outlined above.

8.1.3.1 *GMPS Independent Verification Measurement Uncertainty.* The cumulative uncertainty of the GMPS independent verification measurement approach is integral to the ability to assess the overall quality of the independent verification measurement. You must also document the combined uncertainty, expressed as the root sum of the uncertainty budget items identified.

Ensure that all known or suspected sources of bias and imprecision have been accounted for. The following elements are examples of sources of measurement error that must be included in the overall uncertainty calculation for the GMPS independent verification measurement:

(a) The uncertainty of the certified reference solution (the traceability source);

(b) Any propagated uncertainties through serial dilutions;

(c) The errors in volumetric sampling of the candidate GMPS mixture;

(d) The uncertainty of the instrument calibration curve (least squares fit and residual);

(e) The bias or error associated with any measurement interferences;

(f) The repeatability of replicate aliquot injections from the same sample;

(g) The repeatability of replicate samples of the mixture;

(h) Any external factors influencing sampling or instrument accuracy;

(i) The uncertainty of measured volumetric gas flows;

(j) The bias or uncertainty associated with quantitative gas flow delivery;

(k) The error associated with instrumental measurement analyzers;

(l) Replicate measurement instrument error and precision.

8.1.4 GMPS Certification. The candidate GMPS certified value is based on three factors:

(a) The relative agreement between the gravimetric reference value and the independent, measured value of the gravimetrically-prepared GMPS candidate;

(b) The combined, expanded uncertainty (k=2) of the gravimetric value and independently measured concentrations values;

(c) The average of the independently measured concentrations values.

8.1.4.1 GMPS Relative Agreement. Calculate the relative agreement according to equation B-1, expressed as Relative Percent Difference (RPD) between the gravimetric concentration (GMPS-C_g) the independently measured concentrations (GMPS-C_a). The results of these two analyses must agree within 4.0 percent (%).

$$RPD = \frac{\text{GMPS-C}_g - \text{GMPS-C}_a}{\left(\frac{\text{GMPS-C}_g + \text{GMPS-C}_a}{2}\right)} \qquad \text{Eq. B1}$$

8.1.4.2 GMPS Combined, Expanded Uncertainty. Determine the individual uncertainties for the gravimetric approach (GMPS-C_{ug}) and the independent measurement verification approach (GMPS-C_{ua}) according to equation B-2. Establish the GMPS combined, expanded uncertainty (GMPS-C_{uc}) as the root sum of the two individual uncertainties with a coverage factor k=2. The combined uncertainty must ≤5.0 percent (%). If these objectives are not met, the candidate GMPS is not acceptable, and must not be used.

$$\text{GMPS-C}_{ug} \text{ or } \text{GMPS-C}_{ua} = \sqrt{u_1^2 + u_2^2 + \cdots + u_i^2} \qquad \text{Eq. B2}$$

8.1.4.3 GMPS Certified Concentration Value. If the GMPS meets the Relative Agreement criteria in section 8.1.5.3 and the combined, expanded uncertainty criteria in section 8.1.5.4, the GMPS is valid. The GMPS certified value (GMPS-C_C) is based on the independently measurement concentration (GMPS-C_a). The certification date is the date of the last confirmatory measurement.

8.1.4.4 An SGMs may propose to Administrator an alternative acceptance values for section 8.1.5.1 or 8.1.5.2 for those components that are unable to meet the documented criteria. These proposals must include sufficient documentation that the objectives are unreasonable for a given component and concentrations.

8.1.5 GMPS Stability Testing. The SGM must test and document mixture stability of the GMPS to assure that the mixture stays within claimed accuracy bounds for the entire claimed expiration period. Alternatively, once a preparation process has been developed, the SGM can perform a stability study consisting not less than three cylinders prepared using the defined process and at the concentration(s) defined by the process. Once the stability study cylinders have demonstrated acceptable stability for the minimum expiration period (6-months), additional GMPS cylinders can be prepared under identical process conditions.

8.1.5.1 The SGM may select the sampling frequency based on the targeted expiration period, the gas consumed in the analysis and expected component behavior. Stability testing data must consist of at least:

(a) Five discrete samplings of the retained mixture for an expiration period of 6-months to 1-year;

(b) Ten discrete samplings for an expiration period of 1-3 years; and

(c) Twenty for any period greater than 3 years.

8.1.5.2 Stability testing must be conducted for each cylinder size/type and at a similar concentration as the candidate GMPS. Stability analyses must be performed using methods that assure consistent results can be achieved. If instrumental analysis using a gas standard is employed, use of a GMPS standard is highly recommended. In the absence of a certified GMPS, stability testing must be conducted using the same independent verification measurement procedures and methodology used in section 8.1.4, or using another known-to-be-stable gas standard containing the target component in a similar concentration range.

8.1.5.3 Stability testing data must not show any upward or downward trends that would cause the mixture to become out of specification prior to the claimed expiration period.

8.1.6 GMPS Expiration Period. The expiration period for the GMPS mixture based must be based on the empirical stability test data. The expiration periods for reactive gases must not exceed the length of the stability test, however for non-reactive gases you may forecast an expiration period not to exceed two times the actual stability testing duration. The maximum expiration period for a GMPS is time span from the date of preparation to the date of the last/most recent stability study may not be less than 6-months. Provided that acceptable stability is observed, the maximum expiration period may be extended by retaining the stability study cylinders and performing additional analyses.

8.1.7 GMPS Documentation. You must document the preparation of the GMPS through the appropriate record keeping and document the certification of a GMPS. The information is section 8.1.8.1 and 8.1.8.2 must be maintained as a record by the SGM for the purpose of maintaining traceability and to verify the preparation. The information in section 8.1.8.3 must be documented and maintained by the SGM. This documentation and the records of the preparation and certification must be made available upon request by the appropriate delegated authority.

8.1.7.1 The following information for the gravimetric preparation information of the GMPS must be documented and maintained as a record. This record should include but is not limited to the: blend date, gravimetric concentration, gravimetric concentration uncertainties as a percentage and absolute, reference material information and purity, scale ID, scale accuracy, and calculated gravimetric uncertainties associated with material, balance, and environmental effects. You must include sufficient information that will allow a 3rd party to recalculate the prepared concentration and expanded uncertainties.

8.1.7.2 The following information for the analytical verification of the GMPS must be recorded and maintained as a record. This record should include the confirming methodology and any associated SOPs, confirming concentration(s), instrumentation used, calibration standards used and associated COAs, calibration curve data, replicate analysis calculated, and expanded uncertainties.

8.1.7.3 The following information must be documented for inclusion on the COA for the GMACS.

(a) Manufacturer's company name and address of the producing location

(b) Manufacturer's part number for the GMPS, lot number, and/or production record.

(c) Cylinder number, cylinder type, cylinder preparation ID, moisture dew point and cylinder pressure.

(d) Certification date and claimed expiration date.

(e) GMPS component(s) name, final certified concentration(s) (GMPS-C_c), and balance gas.

(f) Gravimetric value and uncertainty

(g)Verification value and uncertainty

(h) GMPS final certified value and uncertainty absolute as a percentage (GMPS-C_u)

8.2 Preparation and Certification of the GMACS. The preparation and certification of the candidate GMACS is also based on the independent verification of the gravimetrically prepared reference value. However, the independent verification utilizes the GMPS to perform the independent verification. This is accomplished by following the procedures in section 2.1 and 2.2 of the EPA Traceability Protocol, using the GMPS as the certified reference material. The measured value of the independent verification following the EPA Traceability Protocol procedures also establishes the certified reference value, providing the relative agreement performance criteria are met.

8.2.1 GMACS Gravimetric Cylinder Preparation/Creation. The gravimetric preparation of the GMACS is identical to the procedures used to gravimetrically prepare the GMPS. You must maintain the same information required for the gravimetric preparation of GMPS, as found in section 8.1.8.1 for GMACS, as a record.

8.2.2 GMACS Independent Verification and Certification. The candidate GMACS independent verification of the gravimetrically prepared reference value is contingent on the SGM following the procedures in sections 2.1 and 2.2 of the EPA Traceability Protocol. In addition, the EtO candidate GMACS certified reference value and associated expanded uncertainty is based on the EPA Traceability Protocol measured value. This is contingent upon the gravimetric and measured values meeting the relative agreement performance criteria established in section 8.1.5.3 and the uncertainty criteria established in section 8.1.5.4. Gas Manufacturers Intermediate Standards (GMIS) can be prepared by direct comparison to a GMPS that has been prepared and certified according to section 2.1.3.1 and 2.2 of the EPA Traceability Protocol. The tagged value of the GMACS must be based on the EPA Traceability Protocol measured value as long as the performance criteria in sections 12.1 and 12.2 are met.

8.2.3 GMACS Stability Testing. The SGM must test and document the stability of the GMACS to assure that the mixture stays within claimed certified bounds for the entire claimed expiration period. Use the procedures in section 8.1.6 to assess stability. The GMACS must also meet the requirements in section 2.1.5.2 of the EPA Traceability Protocol.

8.2.4 GMACS Expiration Date. The certification period of the GMACS shall be based on the documented stability tests of the GMPS in section 8.1.6. The expiration date shall be based on the certification date, plus the certification period plus one day. There is not a maximum period of expiration; however, expiration periods must not be less than six months.

8.2.5 GMACS Documentation You must document and maintain the same information required for the analytical verification of the GMPS, as found in section 8.1.8 for GMACS, as a record. The records of the preparation and certification must be made available upon request by the appropriate delegated authority.

8.2.6 GMACS Certificate of Analysis (COA). You must provide comprehensive documentation of the GMPS and GMACS development process in the form of a GMACS Certificate of Analysis (COA) that accompanies each commercially distributed GMACS. As a minimum, the COA must contain the following information:

(a) Identification of the gas as a Gas Manufacturer Alternative Certified Standard;

(b) The cylinder number;

(c) The certified concentration of the GMACS;

(d) The combined expanded uncertainty (k=2) of the GMACS reference value (both absolute and relative);

(e) The expiration date;

(f) The reference materials or standards used (*i.e.,* GMPS and GMIS);

(g) The same information (cylinder number, certified concentration, uncertainties, expiration dates, etc. for these cylinders);

(h) The gravimetric and independent measured verification reference concentration values and associated uncertainties for each GMPS used;

(i) Associated measurement principles and uncertainties;

(j) Any additional information stipulated by the EPA Traceability Protocol;

(k) Any comments/special instructions.

The SGM GMACS provider is encouraged to include additional relevant information to the COA, as appropriate. An example GMACS COA can be found in section 14 of this appendix.

9.0 Quality Control—Reserved

10.0 Calibration and Standardization

There is a myriad of instrumental and mechanical techniques used in the performance of this Appendix B. When reference methods are used, you must follow the calibration requirements of those methods and as defined in this appendix. For all other approaches, it is recommended to develop internal SOPs and develop.

11.0 Calculations and Data Analysis—Reserved

12.0 Method Performance

12.1 GMPS/GMACS Relative Agreement. As part of the certification/verification procedures for the candidate GMPS and GMACS, the relative agreement between the gravimetrically prepared reference value and the independently measured verification value must agree within 4.0 percent (%).

12.2 GMACS/GMPS Uncertainty. Final certification of the GMPS and GMACS reference concentrations must meet the combined expanded uncertainty (k=2) of ≤5.0 percent (%).

13.0 Pollution Prevention—Reserved

14.0 Waste Management—Reserved

15.0 Bibliography

1. EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards, Office of Research and Development, National Risk Management Research Laboratory, May 2012, EPA 600/R-12/531. *https://www.epa.gov/air-research/epa-traceability-protocol-assay-and-certification-gaseous-calibration-standards*.

2. EPA Alternative Method 114, Approval of Alternative Method for preparation of HCl Gas Standards for PS-18 and Procedure 6, February 22, 2016, *https://www.epa.gov/sites/default/files/2020-08/documents/alt114.pdf*.

3. Evaluation of Measurement Data—Guide to the Expression of Uncertainty in Measurement, JCGM 100:2008, *https://www.bipm.org/documents/20126/2071204/JCGM_100_2008_E.pdf/cb0ef43f-baa5-11cf-3f85-4dcd86f77bd6*.

16.0 Tables and Figures

Figure B-1 Example Gravimetric Preparation Sheet for GMPS and GMACS

General Information

Project	Operator	Blend Date	Cylinder Number
Phase	Valve Connection	Blend Pressure	Headspace

Component Parameters

	Component 1	Component 2	Component 3	Component 4	Component 5
Material Name					
Material molecular weight (g/mol)					
Dilution Standard or Pure Cylinder Number					
Lot Number					
Dilution Standard Weight Concentration or Pure Weight % Assay (wt%)					
Dilution Standard Weight Accuracy, relative or +/- weight% uncertainty (wt%)					
Dilution Standard or Pure Weight (g)					
Mechanical Effects - u_m (g)					
Scale Capacity Selection (g)					
Scale Calibration Uncertainty - u_{ca} (g)					
Scale Accuracy - u_s (g)					
Weight Standard - u_{ws} (g)					
Material Weight Added (g)					
Material Uncertainty - u_i (g)					
Total Weight Uncertainty (g)					
Additional Weight Uncertainty (g)					

Dilution Standard or Cross Contaminant Additions

Contributing Component #					
Weight Added (g)					
Uncertainty (g)					
Contributing Component #					
Weight Added (g)					
Uncertainty (g)					

Totals Calculations

Total Weight from all additions (g)					
Total moles					

Concentrations and Accuracy Calculations

Weight Concentration (%)					
Weight Accuracy Relative (%)					
Mole Concentration (%)					
Standard Uncertainty - u_i (%)					

Figure B-2 Apparatus for the assay of the GMACs

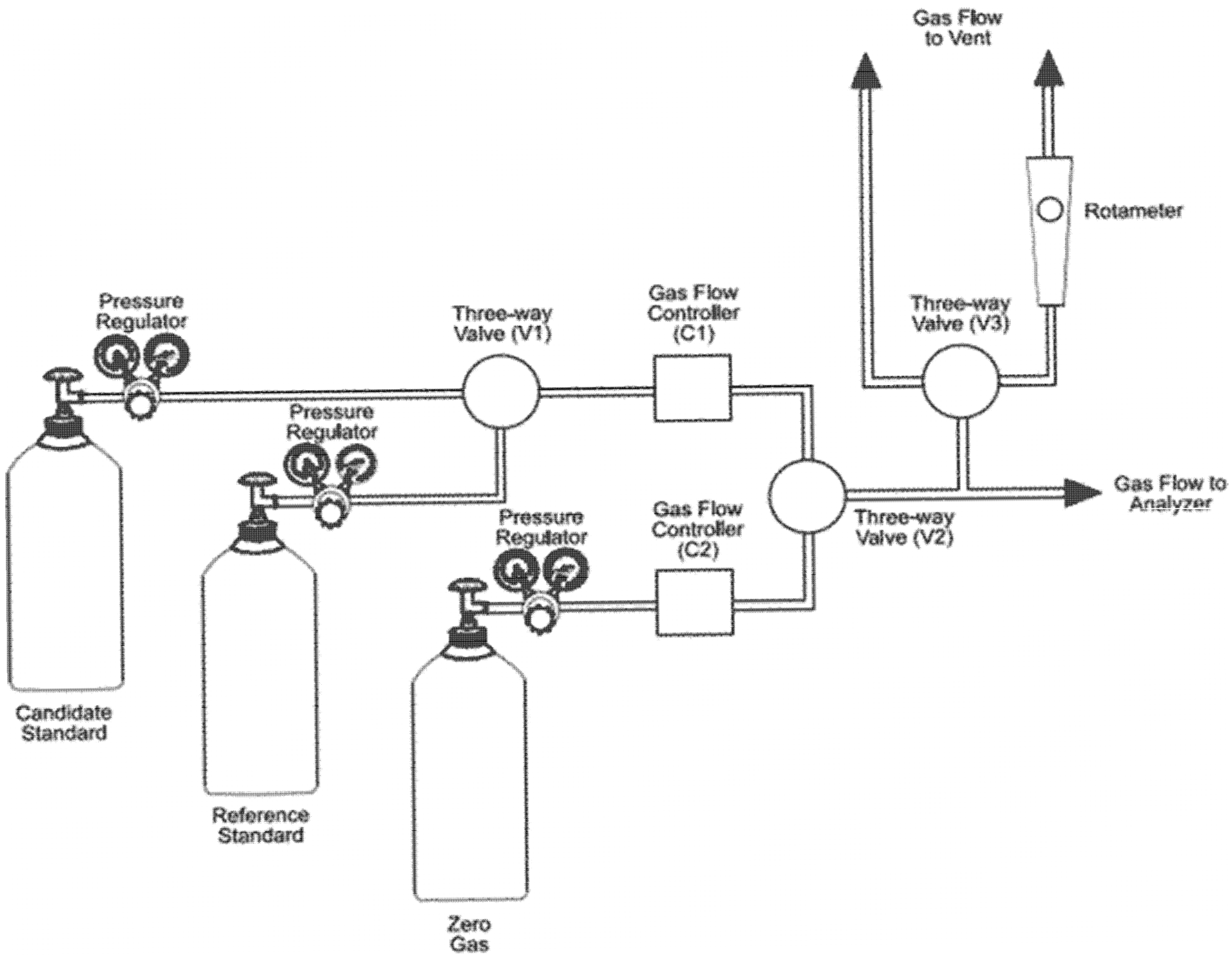

Figure B-3 Examples COA

Example Certificate of Analysis (COA) Ethylene Oxide Gas Manufacturer Alternative Certified Standard

Assay Laboratory		Customer Information
Company Name	Lot Number	Client Name
Company Address		Client Address
City, State, Zip Code		City, State, Zip Code

Product information

Composition	Certified Conc.	Uncertainty (absolute)	Uncertainty (relative)
Ethylene Oxide	X.XXX ppm	X.XX ppm	X.XX %
Nitrogen	Balance		

Cylinder Number:	XXXXXXXXX	Certification Date:	X-XXX-XXXX
Cylinder Type:	XXXXXX	Prior Certification Date:	X-XXX-XXXX
Cylinder Pressure	XXXX	Expiration Date:	X-XXX-XXXX
Mixture Dew Point	XXXX	Part Number:	XXXXXXXXXXXX

Certification Data

Gravimetric Analysis

Composition	Measured Conc.	Uncertainty (absolute)	Uncertainty (relative)
Ethylene Oxide	X.XXX ppm	X.XX ppm	X.XX %

Confirming Analysis

Composition	Measured Conc.	Uncertainty (absolute)	Uncertainty (relative)
Ethylene Oxide	X.XXX ppm	X.XX ppm	X.XX %

Instrument Model/Analytical Principle

XXXXXXXXX/XXXXXXXXXXX

Reference Standard XXXXXXXXXXX

Composition	Measured Conc.	Uncertainty (absolute)	Uncertainty (relative)
Ethylene Oxide	X.XXX ppm	X.XX ppm	X.XX %

[48 FR 13327, Mar. 30, 1983 and 48 FR 23611, May 25, 1983]

Appendix F to Part 60 – Quality Assurance Procedures

Procedure 7. Quality Assurance Requirements for Gaseous Ethylene Exide (ETO) Continuous Emission Monitoring Systems Used for Compliance Determination

1.0 Applicability and Principle

1.1 Applicability. Procedure 7 is used to evaluate the effectiveness of quality control (QC) and quality assurance (QA) procedures and to evaluate the quality of data produced by any ethylene oxide (EtO) gas, CAS: 75-21-8, continuous emission monitoring system (CEMS) that is used for determining compliance with emission standards for EtO on a continuous basis as specified in an applicable permit or regulation.

1.1.1 This procedure specifies the minimum QA requirements necessary for the control and assessment of the quality of CEMS data submitted to the Environmental Protection Agency (EPA) or a delegated authority. If you are responsible for one or more CEMS used for EtO compliance monitoring you must meet these minimum requirements and you are encouraged to develop and implement a more extensive QA program or to continue such programs where they already exist.

1.1.2 Data collected as a result of QA and quality control (QC) measures required in this procedure are to be submitted to the EPA or the delegated authority in accordance with the applicable regulation or permit. These data are to be used by both the delegated authority and you, as the CEMS operator, in assessing the effectiveness of the CEMS QC and QA procedures in the maintenance of acceptable CEMS operation and valid emission data.

1.2 Principle

1.2.1 The QA procedures consist of two distinct and equally important functions. One function is the assessment of the quality of the CEMS data by estimating accuracy. The other function is the control and improvement of the quality of the CEMS data by implementing QC policies and corrective actions. These two functions form an iterative control loop. When the assessment function indicates that the data quality is inadequate, the control effort must be increased until the data quality is acceptable. In order to provide uniformity in the assessment and reporting of data quality, this procedure specifies the assessment procedures to evaluate response drift and accuracy. The procedures specified are based on Performance Specification 19 (PS-19) in appendix B to this part.

Note 1 to section 1.0:

Because the control and corrective action function encompasses a variety of policies, specifications, standards and corrective measures, this procedure treats QC requirements in general terms to allow you, as source owner or operator to develop the most effective and efficient QC system for your circumstances.

2.0 Definitions

See PS-19 in appendix B to this part for the primary definitions used in this Procedure.

3.0 QC Requirements

3.1 You, as a source owner or operator, must develop and implement a QC program. At a minimum, each QC program must include written procedures and/or manufacturer's information which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:

(a) Calibration Drift (CD) checks of CEMS;

(b) CD determination and adjustment of CEMS;

(c) Routine and preventative maintenance of CEMS (including spare parts inventory);

(d) Data recording, calculations, and reporting;

(e) Accuracy audit procedures for CEMS including reference method(s); and

(f) Program of corrective action for malfunctioning CEMS.

3.2 These written procedures must be kept on site and available for inspection by the delegated authority. As described in section 5.4, whenever excessive inaccuracies occur for two consecutive quarters, you must revise the current written procedures, or modify or replace the CEMS to correct the deficiency causing the excessive inaccuracies.

4.0 Daily Data Quality Requirements and Measurement Standardization Procedures

4.1 CD Assessment. An upscale gas, used to meet a requirement in this section must be a gas meeting the requirements in section 7.1 of PS-19 of appendix B to this part.

4.1.1 CD Requirement. Consistent with § 60.13(d) and with § 63.8(c) of this chapter, you, as source owners or operators of CEMS must check, record, and quantify the CD at two levels, using a zero gas and high-level gas at least once daily (approximately every 24 hours). Perform the CD check in accordance with the procedure in the applicable performance specification (*e.g.,* section 11.3 of PS-19 in appendix B to this part). The daily zero- and high-level CD must not exceed two times the drift limits specified in the applicable performance specification (*e.g.,* section 13.2 of PS-19 in appendix B to this part.)

4.1.2 Recording Requirement for CD Corrective action. Corrective actions taken to bring a CEMS back in control after exceeding a CD limit must be recorded and reported with the associated CEMS data. Reporting of a corrective action must include the unadjusted concentration measured prior to resetting the calibration and the adjusted value after resetting the calibration to bring the CEMS back into control.

4.1.3 Dynamic Spiking Option for high-level CD. You have the option to conduct a daily dynamic spiking procedure found in section 11.5.8 of PS-19 of appendix B to this part in lieu of the daily high-level CD check. If this option is selected, the daily zero CD check is still required.

4.1.4 Out of Control Criteria for Excessive CD. Consistent with § 63.8(c)(7)(i)(A) of this chapter, an EtO CEMS is out of control if the zero or high-level CD exceeds two times the applicable CD specification in the applicable performance specification or in the relevant standard. When a CEMS is out of control, you as owner or operator of the affected source must take the necessary corrective actions and repeat the tests that caused the system to go out of control (in this case, the failed CD check) until the applicable performance requirements are met.

4.1.5 Additional Quality Assurance for Data Above Span. This procedure must be used when required by an applicable regulation and may be used when significant data above span are being collected. Furthermore, the terms of this procedure do not apply to the extent that alternate terms are otherwise specified in an applicable rule or permit.

4.1.5.1 Any time the average measured concentration of EtO exceeds 200 percent of the span value for two consecutive one-hour averages, conduct the following 'above span' CEMS response check.

4.1.5.1.1 Within a period of 24 hours (before or after) of the 'above span' period, introduce a higher, 'above span' EtO reference gas standard to the CEMS. Use 'above span' reference gas that meets the requirements of section 7.0 of PS-19 in appendix B to this part and target a concentration level between 75 and 125 percent of the highest hourly concentration measured during the period of measurements above span or 5 ppmv whichever is greater.

4.1.5.1.2 Introduce the reference gas at the probe for extractive CEMS.

4.1.5.1.3 At no time may the 'above span' concentration exceed the analyzer full-scale range.

4.1.5.2 Record and report the results of this procedure as you would for a daily calibration. The 'above span' response check is successful if the value measured by the CEMS is within 20 percent of the certified value of the reference gas.

4.1.5.3 If the 'above span' response check is conducted during the period when measured emissions are above span and there is a failure to collect at least one data point in an hour due to the response check duration, then determine the emissions average for that missed hour as the average of hourly averages for the hour preceding the missed hour and the hour following the missed hour.

4.1.5.4 In the event that the 'above span' response check is not successful (*i.e.,* the CEMS measured value is not within 20 percent of the certified value of the reference gas), then you must normalize the one-hour average stack gas values measured above the span during the 24-hour period preceding or following the 'above span' response check for reporting based on the CEMS response to the reference gas as shown in Eq. 7-1:

$$\text{Normalized stack gas result} = \frac{\textit{Certified reference gas value}}{\textit{Measured value of reference gas}} \; x \; \textit{Measured stack gas result} \qquad \text{Eq. 7-1}$$

4.2 Out of Control Period Duration for Daily Assessments. The beginning of the out-of-control period is the hour in which the owner or operator conducts a daily performance check (*e.g.,* calibration drift) that indicates an exceedance of the performance requirements established under this procedure. The end of the out-of-control period is the completion of daily assessment of the same type following corrective actions, which shows that the applicable performance requirements have been met.

4.3 CEMS Data Status During Out-of-Control Period. During the period the CEMS is out-of-control, the CEMS data may not be used in calculating compliance with an emissions limit nor be counted towards meeting minimum data availability as required and described in the applicable regulation or permit.

5.0 Data Accuracy Assessment

You must audit your CEMS for the accuracy of EtO measurement on a regular basis at the frequency described in this section, unless otherwise specified in an applicable regulation or permit. Quarterly audits are performed at least once each calendar quarter. Successive quarterly audits, to the extent practicable, shall occur no closer than 2 months apart. Annual audits are performed at least once every four consecutive calendar quarters.

5.1 Concentration Accuracy Auditing Requirements. Unless otherwise specified in an applicable regulation or permit, you must audit the EtO measurement accuracy of each CEMS at least once each calendar quarter, except in the case where the affected facility is off-line (does not operate). In that case, the audit must be performed as soon as is practicable in the quarter in which the unit recommences operation. Successive quarterly audits must, to the extent practicable, be performed no less than 2 months apart. The accuracy audits shall be conducted as follows:

5.1.1 Relative Accuracy Test Audit (RATA). A RATA must be conducted at least once every four calendar quarters, except as otherwise noted in sections 5.1.5 or 5.5 of this procedure. Perform the RATA as described in section 11.6 of PS-19 in appendix B to this part. If the EtO concentration measured by the RM during a RATA (in ppmv or other units of the standard) is less than or equal to 20 percent of the concentration equivalent to the applicable emission standard, you must perform a Cylinder Gas Audit (CGA) or a Dynamic Spike Audit (DSA) for at least one subsequent (one of the following three) quarterly accuracy audits.

5.1.2 Quarterly Relative Accuracy Audit (RAA). A quarterly RAA may be conducted as an option to conducting a RATA in three of four calendar quarters, but in no more than three quarters in succession. To conduct an RAA, follow the test procedures in section 11.6 of PS-19 in appendix B to this part, except that only three test runs are required. The difference between the mean of the RM values and the mean of the CEMS responses relative to the mean of the values (or alternatively the emission standard) is used to assess the accuracy of the CEMS. Calculate the RAA results as described in section 6.2. As an alternative to an RAA, a cylinder gas audit or a dynamic spiking audit may be conducted.

5.1.3 Cylinder Gas Audit. A quarterly CGA may be conducted as an option to conducting a RATA in three of four calendar quarters, but in no more than three consecutive quarters. To perform a CGA, challenge the CEMS with a zero-level and two upscale level audit gases of known concentrations within the following ranges:

Audit point	Audit range
1 (Mid-Level)	50 to 60% of span value.
2 (High-Level)	80 to 100% of span value.

5.1.3.1 Inject each of the three audit gases (zero and two upscale) three times each for a total of nine injections. Inject the gases so that the entire measurement system is challenged. Do not inject the same gas concentration twice in succession.

5.1.3.2 Use EtO audit gases that meet the requirements of section 7 of PS-19 in appendix B to this part.

5.2.3.3 Calculate results as described in section 6.3.

5.1.4 Dynamic Spiking Audit. A quarterly DSA may be conducted as an option to conducting a RATA in three of four calendar quarters, but in no more than three quarters in succession.

5.1.4.1 To conduct a DSA, you must challenge the entire EtO CEMS with a zero gas in accordance with the procedure in section 11.8 of PS-19 in appendix B of this part. You must also conduct the DS procedure as described in appendix A to PS-19 of appendix B to this part. You must conduct three spike injections with each of two upscale level audit gases. The upscale level gases must meet the requirements of section 7 of PS-19 in appendix B to this part and must be chosen to yield concentrations at the analyzer of 50 to 60 percent of span and 80 to 100 percent of span. Do not inject the same spike gas concentration twice in succession.

5.1.4.2 Calculate results as described in section 6.4. To determine CEMS accuracy, you must calculate the dynamic spiking error (DSE) for each of the two upscale audit gases using equation A5 in appendix A to PS-19 and equation 7-3 in section 6.4 of this Procedure.

5.1.5 Other Alternative Quarterly Audits. Other alternative audit procedures, as approved by the Administrator, may be used for three of four calendar quarters.

5.2 Out of Control Criteria for Excessive Audit Inaccuracy. If the results of the RATA, RAA, CGA, or DSA do not meet the applicable performance criteria in section 5.2.4, the CEMS is out-of-control. If the CEMS is out-of-control, take necessary corrective action to eliminate the problem. Following corrective action, the CEMS must pass a test of the same type that resulted in the out-of-control period to determine if the CEMS is operating within the specifications (*e.g.,* a RATA must always follow an out-of-control period resulting from a RATA).

5.2.1 If the audit results show the CEMS to be out-of-control, you must report both the results of the audit showing the CEMS to be out-of-control and the results of the audit following corrective action showing the CEMS to be operating within specifications.

5.2.2 Out-Of-Control Period Duration for Excessive Audit Inaccuracy. The beginning of the out-of-control period is the time corresponding to the completion of the sampling for the failed RATA, RAA, CGA or DSA. The end of the out-of-control period is the time corresponding to the completion of the sampling of the subsequent successful audit.

5.2.3 CEMS Data Status During Out-Of-Control Period. During the period the CEMS is out-of- control, the CEMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability as required and described in the applicable regulation or permit.

5.2.4 Criteria for Excessive Quarterly and Yearly Audit Inaccuracy. Unless specified otherwise in the applicable regulation or permit, the criteria for excessive inaccuracy are:

5.2.4.1 For the RATA, the CEMS must meet the RA specifications in section 13.4 of PS-19 in appendix B to this part.

5.2.4.2 For the CGA, the accuracy must not exceed 10.0 percent of the span value at the zero gas and the mid- and high-level reference gas concentrations.

5.2.4.3 For the RAA, the RA must not exceed 20.0 percent of the RMavg as calculated using equation 7-2 in section 6.2 of this procedure whether calculated in units of EtO concentration or in units of the emission standard. In cases where the RA is calculated on a concentration (ppbv) basis, if the average EtO concentration measured by the RM during the test is less than 75 percent of the EtO concentration equivalent to the applicable standard, you may substitute the equivalent emission standard value (in ppbw) in the denominator of equation 7-2 in the place of RM_{avg} and the result of this alternative calculation of RA must not exceed 15.0 percent.

5.2.4.4 For DSA, the accuracy must not exceed 5.0 percent of the span value at the zero gas and the mid- and high-level reference gas concentrations or 20.0 percent of the applicable emission standard, whichever is greater.

5.3 Criteria for Acceptable QC Procedures. Repeated excessive inaccuracies (*i.e.,* out-of-control conditions resulting from the quarterly or yearly audits) indicate that the QC procedures are inadequate or that the CEMS is incapable of providing quality data. Therefore, whenever excessive inaccuracies occur for two consecutive quarters, you must revise the QC procedures (see section 3.0) or modify or replace the CEMS.

5.4 Criteria for Optional QA Test Frequency. If all the quality criteria are met in sections 4 and 5 of this procedure, the CEMS is in-control.

5.5.1 Unless otherwise specified in an applicable rule or permit, if the CEMS is in-control and if your source emits ≤75 percent of the EtO emission limit for each averaging period as specified in the relevant standard for eight consecutive quarters that include a minimum of two RATAs, you may revise your auditing procedures to use CGA, RAA or DSA each quarter for seven subsequent quarters following a RATA.

5.5.2 You must perform at least one RATA that meets the acceptance criteria every 2 years.

5.5.3 If you fail a RATA, RAA, CGA, or DSA, then the audit schedule in section 5.2 must be followed until the audit results meet the criteria in section 5.3.4 to start requalifying for the optional QA test frequency in section 5.5.

6.0 Calculations for CEMS Data Accuracy

6.1 RATA RA Calculation. Follow equations 9 through 14 in section 12 of PS-19 in appendix B to this part to calculate the RA for the RATA. The RATA must be calculated either in units of the applicable emission standard or in concentration units (ppbv).

6.2 RAA Accuracy Calculation. Use equation 7-2 to calculate the accuracy for the RAA. The RA may be calculated in concentration units (ppmv) or in the units of the applicable emission standard.

$$RA = \frac{MN_{avg} - RM_{avg}}{RM_{avg}} x \; 100 \qquad \text{Eq. 7-2}$$

Where:

RA = Accuracy of the CEMS (percent)

MN_{avg} = Average measured CEMS response during the audit in units of applicable standard or appropriate concentration.

RM_{avg} = Average reference method value in units of applicable standard or appropriate concentration.

6.3 CGA Accuracy Calculation. For each gas concentration, determine the average of the three CEMS responses and subtract the average response from the audit gas value. For extractive CEMS, calculate the ME at each gas level using equation 3A in section 12.3 of PS-19 of appendix B to this part.

6.4 DSA Accuracy Calculation. DSA accuracy is calculated as a percent of span. To calculate the DSA accuracy for each upscale spike concentration, first calculate the DSE using equation A5 in appendix A of PS-19 in appendix B to this part. Then use equation 7-3 to calculate the average DSA accuracy for each upscale spike concentration. To calculate DSA accuracy at the zero level, use equation 3A in section 12.3 of PS-19 in appendix B to this part.

$$\text{DSA Accuracy} = \frac{\sum_1^3 \left[\frac{|DSEi|}{S}\right]}{3} x100 \qquad \text{Eq. 7-3}$$

7.0 Reporting Requirements

At the reporting interval specified in the applicable regulation or permit, report for each CEMS the quarterly and annual accuracy audit results from section 6 and the daily assessment results from section 4. Unless otherwise specified in the applicable regulation or permit, include all data sheets, calculations, CEMS data records (*i.e.,* charts, records of CEMS responses), reference gas certifications and reference method results necessary to confirm that the performance of the CEMS met the performance specifications.

7.1 Unless otherwise specified in the applicable regulations or permit, report the daily assessments (CD and beam intensity) and accuracy audit information at the interval for emissions reporting required under the applicable regulations or permits.

7.1.1 At a minimum, the daily assessments and accuracy audit information reporting must contain the following information:

a. Company name and address.

b. Identification and location of monitors in the CEMS.

c. Manufacturer and model number of each monitor in the CEMS.

d. Assessment of CEMS data accuracy and date of assessment as determined by a RATA, RAA, CGA or DSA described in section 5 including:

i. The RA for the RATA;

ii. The accuracy for the CGA, RAA, or DSA;

iii. The RM results, the reference gas certified values;

iv. The CEMS responses;

v. The calculation results as defined in section 6; and

vi. Results from the performance audit samples described in section 5 and the applicable RMs.

e. Summary of all out-of-control periods including corrective actions taken when CEMS was determined out-of-control, as described in sections 4 and 5. 7.1.2 If the accuracy audit results show the CEMS to be out-of-control, you must report both the audit results showing the CEMS to be out-of-control and the results of the audit following corrective action showing the CEMS to be operating within specifications.

7.1.2 If the accuracy audit results show the CEMS to be out-of-control, you must report both the audit results showing the CEMS to be out-of-control and the results of the audit following corrective action showing the CEMS to be operating within specifications.

8.0 Bibliography

1. EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards, U.S. Environmental Protection Agency office of Research and Development, EPA/600/R-12/531, May 2012.

2. Method 205, "Verification of Gas Dilution Systems for Field Instrument Calibrations," 40 CFR part 51, appendix M.

9.0 [Reserved]

[52 FR 21008, June 4, 1987; 52 FR 27612, July 22, 1987, as amended at 56 FR 5527, Feb. 11, 1991; 69 FR 1816, Jan. 12, 2004; 72 FR 32768, June 13, 2007; 74 FR 12590, Mar. 25, 2009; 75 FR 55040, Sept. 9, 2010; 79 FR 11274, Feb. 27, 2014; 79 FR 28441, May 16, 2014; 80 FR 38649, July 7, 2015; 81 FR 59824, Aug. 30, 2016; 82 FR 37824, Aug. 14, 2017; 82 FR 44108, Sept. 21, 2017; 83 FR 56725, Nov. 14, 2018; 85 FR 63418, Oct. 7, 2020; 88 FR 18411, Mar. 29, 2023; 89 FR 24168, Apr. 5, 2024]

Final, which are available in the docket for this rulemaking. Also see the document titled *Analysis of Demographic Factors for Populations Living Near Polymers and Resins I and Polymer and Resins II Facilities* (Docket Item No. EPA–HQ–OAR–2022–0730–0060).

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

40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 63

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

Michael S. Regan,

Administrator.

For the reasons set out in the preamble, the Environmental Protection Agency amends title 40, chapter I, part 60 of the Code of Federal Regulations as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

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

Subpart A—General Provisions

■ 2. Amend § 60.17 by:
■ a. Revising paragraph (a), paragraphs (c) introductory text, (d) introductory text, and (e) introductory text, and paragraph (g)(14);
■ b. In paragraph (h):
■ i. Redesignating paragraphs (h)(221) through (228) as (h)(226) through (233), (h)(196) through (220) as (h)(200) through (224), (h)(171) through (195) as (h)(174) through (198), (h)(115) through (170) as (h)(117) through (172), and (h)(28) through (114) as (h)(29) through (115);
■ ii. Adding new paragraph (h)(28);
■ iii. Revising newly redesignated paragraph (h)(78);
■ iv Adding new paragraphs (h)(116), (173), and (199);
■ v. Revising newly redesignated paragraphs (h)(217) and (221), and
■ vi. Adding new paragraph (h)(225); and
■ c. Revising and republishing paragraph (j); and
■ d. Removing note 1 to paragraph (k).

The revisions and additions read as follows:

§ 60.17 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), see paragraph (d) of this section.

(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*.

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(c) American Hospital Association (AHA) Service, Inc., Post Office Box 92683, Chicago, Illinois 60675–2683.

* * * * *

(d) 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*.

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(e) American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001; phone: (202) 682–8000; website: *www.api.org*.

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(g) * * *

(14) ASME/ANSI PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], Issued August 31, 1981; IBR approved for §§ 60.56c(b); 60.63(f); 60.106(e); 60.104a(d), (h), (i), and (j); 60.105a(b), (d), (f), and (g); 60.106a(a); 60.107a(a), (c), and (d); 60.275(e); 60.275a(e); 60.275b(e); tables 1 and 3 to subpart EEEE; tables 2 and 4 to subpart FFFF; table 2 to subpart JJJJ; §§ 60.285a(f); 60.396(a); 60.614a(b); 60.664a(b); 60.704(b); 60.704a(b); 60.2145(s) and (t); 60.2710(s) and (t); 60.2730(q); 60.4415(a); 60.4900(b); 60.5220(b); tables 1 and 2 to subpart LLLL; tables 2 and 3 to subpart MMMM; §§ 60.5406(c); 60.5406a(c); 60.5406b(c); 60.5407a(g); 60.5407b(g); 60.5413(b); 60.5413a(b) and (d); 60.5413b(d) and (d); 60.5413c(b) and (d).

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(h) * * *

(28) ASTM D240–19, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, approved November 1, 2019; IBR approved for § 60.485b(g).

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(78) ASTM D1945–14 (Reapproved 2019), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, approved December 1, 2019; IBR approved for § 60.485b(g).

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(116) ASTM D2879–23, Standard Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, approved December 1, 2019; IBR approved for § 60.485b(e).

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(173) ASTM D4809–18, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), approved July 1, 2018; IBR approved for § 60.485b(g).

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(199) 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 §§ 60.485(g); 60.485a(g); 60.485b(g); 60.611a;

60.614(b) and (e); 60.614a(b) and (e), 60.664(b) and (e); 60.664a(b) and (f); 60.700(c); 60.704(b) (d), and (h); 60.705(l); 60.704a(b) and (f).

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(217) ASTM E168–16 (Reapproved 2023), Standard Practices for General Techniques of Infrared Quantitative Analysis, approved January 1, 2023; IBR approved for § 60.485b(d).

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(221) ASTM E169–16 (Reapproved 2022), Standard Practices for General Techniques of Ultraviolet-Visible Quantitative Analysis, approved November 1, 2022; IBR approved for § 60.485b(d).

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(225) ASTM E260–96 (Reapproved 2019), Standard Practice for Packed Column Gas Chromatography, approved September 1, 2029; IBR approved for § 60.485b(d).

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(j) 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 Operations, September 2008, Office of Air Quality Planning and Standards (OAQPS); IBR approved for §§ 60.393a(e) and (h); 60.395a(k); 60.397a(e); appendix A to subpart MMa.

(2) EPA–454/B–08–002, Quality Assurance Handbook for Air Pollution Measurement Systems; Volume IV: Meteorological Measurements, Version 2.0 (Final), March 2008; IBR approved for appendix K to this part.

(3) EPA–454/R–98–015, Office of Air Quality Planning and Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance, September 1997; IBR approved for §§ 60.124(f); 60.124a(f); 60.273(e); 60.273a(e); 60.273b(e); 60.373a(b); 60.2145(r); 60.2710(r); 60.4905(b); 60.5225(b). (Available from: *https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=2000D5T6.pdf*).

(4) EPA–600/R–12/531, EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards, May 2012; IBR approved for §§ 60.5413(d); 60.5413a(d); 60.5413b(d); 60.5413c(d).

(5) 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–846–6010D, Inductively Coupled Plasma-Optical Emission Spectrometry, Revision 5, July 2018; IBR approved for appendix A–5 to this part.

(ii) SW–846–6020B, Inductively Coupled Plasma-Mass Spectrometry, Revision 2, July 2014; IBR approved for appendix A–5 to this part.

* * * * *

■ 3. Amend § 60.480 by revising paragraph (f) to read as follows:

§ 60.480 Applicability and designation of affected facility.

* * * * *

(f) *Overlap with other regulations for flares.* 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 this part or 40 CFR 61 or 63, may elect to comply with the requirements in § 60.619a, § 60.669a, or § 60.709a, in lieu of all flare related requirements in any other regulation in this part or 40 CFR part 61 or 63.

■ 4. Amend § 60.481 by revising the definition of ''Process unit'' to read as follows:

§ 60.481 Definitions.

* * * * *

Process unit means components assembled to produce, as intermediate or final products, one or more of the chemicals listed in § 60.489 of this part. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

* * * * *

§ 60.482–1 [Amended]

■ 5. Amend § 60.482–1 by removing paragraph (g).

■ 6. Amend § 60.485 by revising paragraph (g)(5) to read as follows:

§ 60.485 Test methods and procedures.

* * * * *

(g) * * *

(5) Method 18 of appendix A–6 to this part and ASTM D2504–67, 77 or 88 (Reapproved 1993) (incorporated by reference, see § 60.17) shall be used to determine the concentration of sample component ''i.'' ASTM D6420–18 (incorporated by reference, see § 60.17) may be used in lieu of Method 18, under the conditions specified in paragraphs (g)(5)(i) through (iii) of this section.

(i) If the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable.

(ii) ASTM D6420–18 may not be used for methane and ethane.

(iii) ASTM D6420–18 may not be used as a total VOC method.

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■ 7. Amend § 60.486 by adding paragraph (l) as follows:

§ 60.486 Recordkeeping requirements.

* * * * *

(l) Any records required to be maintained by this subpart that are submitted electronically via the EPA's 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 air agency or the EPA as part of an on-site compliance evaluation.

■ 8. Amend § 60.487 by revising paragraphs (a) and (f) and adding paragraphs (g), (h), and (i) to read as follows:

§ 60.487 Reporting requirements.

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning six months after the initial startup date. Beginning on July 15, 2025, 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 1 year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (g) of this section. 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.

* * * * *

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the State. The EPA will not approve a waiver of electronic reporting to the

EPA in delegating enforcement authority. Thus, electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph cannot be used to relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

(g) If an owner or operator is required to submit notifications or reports following the procedure specified in this paragraph (g), the owner or operator must submit notifications or 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 the owner or operator. Do not use CEDRI to submit information the owner or operator claims as CBI. Although the EPA does not expect persons to assert a claim of CBI, if an owner or operator wishes to assert a CBI claim for some of the information in the report or notification, the owner or operator must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. Clearly mark the part or all of the information claimed 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. The owner or operator 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 (g).

(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. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the SOCMI NSPS Sector Lead. Owners and operators who do not have their own file sharing service and who require assistance with submitting large electronic files that exceed the file size limit for email attachments should email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If an owner or operator cannot transmit the file electronically, the owner or operator may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the SOCMI NSPS Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(h) Owners and operators required to electronically submit notifications or reports through CEDRI in the EPA's CDX 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, owner and operator must meet the requirements outlined in paragraphs (h)(1) through (7) of this section.

(1) The owner or operator 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) The owner or operator must submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) The owner or operator 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 the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the report was submitted.

(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) Owners and operators required to electronically submit notifications or reports through CEDRI in the EPA's CDX may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure,* owners and operators must meet the requirements outlined in paragraphs (i)(1) through (5) of this section.

(1) The owner or operator 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 the owner or operator 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) The owner or operator must submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) The owner or operator 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 the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the report was submitted.

(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.

■ 9. Revise the heading of subpart VVa to read as follows:

Subpart VVa—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, and on or Before April 25, 2023

■ 10. Amend § 60.480a by revising paragraphs (b), revising and republishing paragraph (d), and revising paragraph (f) to read as follows:

§ 60.480a Applicability and designation of affected facility.

* * * * *

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 7, 2006, and on or before April 25, 2023, shall be subject to the requirements of this subpart.

* * * * *

(d)(1) If an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in § 60.486a(i).

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) of a chemical listed in § 60.489 is exempt from §§ 60.482–1a through 60.482–10a.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from §§ 60.482–1a through 60.482–10a.

(4) Any affected facility that produces beverage alcohol is exempt from §§ 60.482–1a through 60.482–10a.

(5) Any affected facility that has no equipment in volatile organic compounds (VOC) service is exempt from §§ 60.482–1a through 60.482–10a.

* * * * *

(f) 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 this part or 40 CFR part 61 or 63, may elect to comply with the requirements in § 60.619a, § 60.669a, or § 60.709a, in lieu of all flare related requirements in any other regulation in this part or 40 CFR part 61 or 63.

■ 11. Amend § 60.481a by revising the definitions of ''Capital expenditure'' and ''Process Unit'' to read as follows:

§ 60.481a Definitions.

* * * * *

Capital expenditure means, in addition to the definition in § 60.2, an expenditure for a physical or operational change to an existing facility that:

(1) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(i) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

Equation 1 to Capital Expenditure Paragraph (1)(i)

$$A = Y \times (B \div 100);$$

(ii) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is:

(A) 2006 minus the year of construction if the physical or operational change to the existing facility was on or after November 16, 2007, or

(B) 1982 minus the year of construction if the physical or operational change to the existing facility was prior to November 16, 2007; and

(iii) The applicable basic annual asset guideline repair allowance, B, is selected from the following table consistent with the applicable subpart:

TABLE 1 TO CAPITAL EXPENDITURE PARAGRAPH (1)(iii)—DETERMINING APPLICABLE VALUE FOR B

Subpart applicable to facility	Value of B to be used in equation
(A) VVa	12.5
(B) GGGa	7.0

* * * * *

Process unit means components assembled to produce, as intermediate or final products, one or more of the chemicals listed in § 60.489a. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

* * * * *

■ 12. Amend § 60.482–1a by revising paragraph (e) introductory text and removing paragraph (g).

The revision reads as follows:

§ 60.482–1a Standards: General.

* * * * *

(e) Equipment that an owner or operator designates as being in VOC service less than 300 hr/yr is excluded from the requirements of §§ 60.482–2a through 60.482–10a if it is identified as required in § 60.486a(e)(6) and it meets any of the conditions specified in paragraphs (e)(1) through (3) of this section.

* * * * *

§ 60.482–11a [Removed]

■ 13. Remove § 60.482–11a.

■ 14. Amend § 60.485a by revising paragraphs (b) and (g)(5) to read as follows:

§ 60.485a Test methods and procedures.

* * * * *

(b) The owner or operator shall determine compliance with the standards in §§ 60.482–1a through 60.482–10a, 60.483a, and 60.484a as follows:

(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A–7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(2) A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 to this part, section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in § 60.486a(e)(8). Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage.

(i) If a calibration drift assessment shows a negative drift of more than 10 percent, then all equipment with instrument readings between the appropriate leak definition and the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) that was monitored since the last calibration must be re-monitored.

(ii) If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) monitored since the last calibration may be re-monitored.

* * * * *

(g) * * *

(5) Method 18 of appendix A–6 to this part and ASTM D2504–67, 77, or 88 (Reapproved 1993) (incorporated by reference, see § 60.17) shall be used to determine the concentration of sample component "i." ASTM D6420–18 (incorporated by reference, see § 60.17) may be used in lieu of Method 18, under the conditions specified in paragraphs (g)(5)(i) through (iii) of this section.

(i) If the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable.

(ii) ASTM D6420–18 may not be used for methane and ethane.

(iii) ASTM D6420–18 may not be used as a total VOC method.

* * * * *

■ 15. Amend § 60.486a by:

■ a. Revising paragraphs (a)(3) introductory text and (b) introductory text;

■ b. Removing and reserving paragraph (b)(3);

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

■ d. Removing and reserving paragraph (e)(9);

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

■ f. Adding paragraph (l).

The revisions and addition read as follows:

§ 60.486a Recordkeeping requirements.

(a) * * *

(3) The owner or operator shall record the information specified in paragraphs (a)(3)(i) through (v) of this section for each monitoring event required by §§ 60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, and 60.483–2a.

* * * * *

(b) When each leak is detected as specified in §§ 60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, and 60.483–2a, the following requirements apply:

* * * * *

(c) When each leak is detected as specified in §§ 60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, and 60.483–2a, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

* * * * *

(e) The following information pertaining to all equipment subject to the requirements in §§ 60.482–1a to 60.482–10a shall be recorded in a log that is kept in a readily accessible location:

* * * * *

(f) The following information pertaining to all valves subject to the requirements of § 60.482–7a(g) and (h), and all pumps subject to the requirements of § 60.482–2a(g) shall be recorded in a log that is kept in a readily accessible location:

* * * * *

(l) Any records required to be maintained by this subpart that are submitted electronically via the EPA's 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 air agency or the EPA as part of an on-site compliance evaluation.

■ 16. Amend § 60.487a by:

■ a. Revising paragraph (a);

■ b. Removing paragraph (b)(5);

■ c. Revising paragraph (c)(2)(vi);

■ d. Removing and reserving paragraphs (c)(2)(vii) and (viii):

■ e. Revising paragraph (f); and

■ f. Adding paragraphs (g), (h) and (i).

The revisions and additions read as follows:

§ 60.487a Reporting requirements.

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date. Beginning on July 15, 2025, 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 1 year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (g) of this section. 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.

* * * * *

(c) * * *

(2) * * *

(vi) Number of compressors for which leaks were not repaired as required in § 60.482–3a(g)(1), and

* * * * *

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the state. The EPA will not approve a waiver of electronic reporting to the EPA in delegating enforcement authority. Thus, electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph cannot be used to relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

(g) If an owner or operator is required to submit notifications or reports following the procedure specified in this paragraph (g), the owner or operator must submit notifications or 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 the owner or operator. Do not use CEDRI to submit information the owner or operator claims as CBI. Although the EPA does not expect persons to assert a claim of CBI, if you an owner or operator wishes to assert a CBI claim for some of the information in the report or notification, the owner or operator must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. Clearly mark the part or all of the information claimed 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. The owner or operator 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 (g).

(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. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the SOCMI NSPS Sector Lead. Owners and operators who do not have their own file sharing service and who require assistance with submitting large electronic files that exceed the file size limit for email attachments should email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If an owner or operator cannot transmit the file electronically, the owner or operator may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the SOCMI NSPS Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(h) Owners and operators required to electronically submit notifications or reports through CEDRI in the EPA's CDX 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, owners and operators must meet the requirements outlined in paragraphs (h)(1) through (7) of this section.

(1) The owner or operator 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) The owner or operator must submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) The owner or operator 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 the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the report was submitted.

(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) Owners and operators required to electronically submit notifications or reports through CEDRI in the EPA's CDX may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure,* owners and operators must meet the requirements outlined in paragraphs (i)(1) through (5) of this section.

(1) An owner or operator 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 the owner or operator 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) The owner or operator must submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) The owner or operator 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 the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the report was submitted.

(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.

■ 17. Add subpart VVb to read as follows:

Subpart VVb—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After April 25, 2023

Subpart VVb—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After April 25, 2023

§ 60.480b Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

(2) The group of all equipment (defined in § 60.481b) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after April 25, 2023, shall be subject to the requirements of this subpart.

(c) Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d)(1) If an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in § 60.486b(i).

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) of a chemical listed in § 60.489 is exempt from §§ 60.482–1b through 60.482–11b.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from §§ 60.482–1b through 60.482–11b.

(4) Any affected facility that produces beverage alcohol is exempt from §§ 60.482–1b through 60.482–11b.

(5) Any affected facility that has no equipment in volatile organic compounds (VOC) service is exempt from §§ 60.482–1b through 60.482–11b.

(e)(1) *Option to comply with 40 CFR part 65.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 65, subpart F, to satisfy the requirements of §§ 60.482–1b through 60.487b for an affected facility. When choosing to comply with 40 CFR part 65, subpart F, the requirements of §§ 60.485b(d), (e), and (f), and 60.486b(i) and (j) still apply. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

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

(2) *Option to comply with 40 CFR part 63, subpart H.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 63, subpart H, to satisfy the requirements of §§ 60.482–1b through 60.487b for an affected facility. When choosing to comply with 40 CFR part 63, subpart H, the requirements of § 60.482–7b, § 60.485b(d), (e), and (f), and § 60.486b(i) and (j) still apply.

(ii) Owners or operators who choose to comply with 40 CFR part 63, subpart H must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs that are not mentioned in this paragraph (e)(2)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 63, subpart H, except that provisions required to be met prior to implementing 40 CFR part 63 still apply. Owners and operators who choose to comply with 40 CFR part 63, subpart H, must comply with 40 CFR part 63, subpart A.

(f) 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 this part or 40 CFR part 61 or 63, may elect to comply with the requirements in § 60.619a, § 60.669a, or § 60.709a, in lieu of all flare related requirements in any other regulation in this part or 40 CFR part 61 or 63.

§ 60.481b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act (CAA) or in subpart A of this part, and the following terms shall have the specific meanings given them.

Capital expenditure means, in addition to the definition in § 60.2, an expenditure for a physical or operational change to an existing facility that:

(1) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(i) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

Equation 1 to Capital Expenditure Paragraph (1)(i)

$$A = Y \times (B \div 100);$$

(ii) The percent Y is determined from the following equation: Y = (CPI of date of construction/most recently available CPI of date of project), where the ''CPI–U, U.S. city average, all items'' must be used for each CPI value; and

(iii) The applicable basic annual asset guideline repair allowance, B, is 12.5.

Closed-loop system means an enclosed system that returns process fluid to the process.

Closed-purge system means a system or combination of systems and portable containers to capture purged liquids. Containers for purged liquids 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 that is composed of hard-piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back to a process.

Connector means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.

Control device means an enclosed combustion device, vapor recovery system, or flare.

Distance piece means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.

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.

Equipment means each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart.

First attempt at repair means to take action for the purpose of stopping or reducing leakage of organic material to the atmosphere using best practices.

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-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

Hard-piping means pipe or tubing that is manufactured and properly installed using good engineering judgment and standards such as ASME B31.3, Process Piping (available from the American Society of Mechanical Engineers, P.O. Box 2300, Fairfield, NJ 07007–2300).

In gas/vapor service means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.

In heavy liquid service means that the piece of equipment is not in gas/vapor service or in light liquid service.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485b(e).

In-situ sampling systems means nonextractive samplers or in-line samplers.

In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa) (0.7 psia) below ambient pressure.

In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of § 60.485b(d) specify how to determine that a piece of equipment is not in VOC service.)

Initial calibration value means the concentration measured during the initial calibration at the beginning of each day required in § 60.485b(b)(1), or the most recent calibration if the instrument is recalibrated during the day (*i.e.,* the calibration is adjusted) after a calibration drift assessment.

Liquids dripping means any visible leakage from the seal including spraying, misting, clouding, and ice formation.

Open-ended valve or line means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

Pressure release means the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

Process improvement means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

Process unit means components assembled to produce, as intermediate or final products, one or more of the chemicals listed in § 60.489. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. The following are not considered process unit shutdowns:

(1) 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.

(2) 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.

(3) The use of spare equipment and technically feasible bypassing of equipment without stopping production.

Quarter means a 3-month period; the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

Repaired means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of this subpart and, except for leaks identified in accordance with §§ 60.482–2b(b)(2)(ii) and (d)(6)(ii) and (iii), 60.482–3b(f), and 60.482–10b(f)(1)(ii), is re-monitored as specified in § 60.485b(b) to verify that emissions from the equipment are below the applicable leak definition.

Replacement cost means the capital needed to purchase all the depreciable components in a facility.

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 nonroutine grab samples is not considered a sampling connection system.

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.

Storage vessel means a tank or other vessel that is used to store organic liquids that are used in the process as raw material feedstocks, produced as intermediates or final products, or generated as wastes. Storage vessel does not include vessels permanently attached to motor vehicles, such as trucks, railcars, barges or ships.

Synthetic organic chemicals manufacturing industry means the industry that produces, as intermediates or final products, one or more of the chemicals listed in § 60.489.

Transfer rack means the collection of loading arms and loading hoses, at a single loading rack, that are used to fill tank trucks and/or railcars with organic liquids.

Volatile organic compounds or VOC means, for the purposes of this subpart, any reactive organic compounds as defined in § 60.2.

§ 60.482–1b Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§ 60.482–1b through 60.482–11b or § 60.480b(e) for all equipment within 180 days of initial startup.

(b) Compliance with §§ 60.482–1b through 60.482–11b will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in § 60.485b.

(c)(1) An owner or operator may request a determination of equivalence of a means of emission limitation to the requirements of §§ 60.482–2b, 60.482–3b, 60.482–5b, 60.482–6b, 60.482–7b, 60.482–8b, and 60.482–10b as provided in § 60.484b.

(2) If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of § 60.482–2b, § 60.482–3b, § 60.482–5b, § 60.482–6b, § 60.482–7b, § 60.482–8b, or § 60.482–10b, an owner or operator shall comply with the requirements of that determination.

(d) Equipment that is in vacuum service is excluded from the requirements of §§ 60.482–2b through 60.482–11b if it is identified as required in § 60.486b(e)(5).

(e) Equipment that an owner or operator designates as being in VOC service less than 300 hr/yr is excluded from the requirements of §§ 60.482–2b through 60.482–11b if it is identified as required in § 60.486b(e)(6) and it meets any of the conditions specified in paragraphs (e)(1) through (3) of this section.

(1) The equipment is in VOC service only during startup and shutdown, excluding startup and shutdown between batches of the same campaign for a batch process.

(2) The equipment is in VOC service only during process malfunctions or other emergencies.

(3) The equipment is backup equipment that is in VOC service only when the primary equipment is out of service.

(f)(1) If a dedicated batch process unit operates less than 365 days during a year, an owner or operator may monitor to detect leaks from pumps, valves, and open-ended valves or lines at the frequency specified in the following table instead of monitoring as specified in §§ 60.482–2b, 60.482–7b, and 60.483.2a:

TABLE 1 TO PARAGRAPH (f)(1)

Operating time (percent of hours during year)	Equivalent 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 quarters	Semiannually.
75 to 100	Monthly	Quarterly	Semiannually.

(2) Pumps and valves that are shared among two or more batch process units that are subject to this subpart may be monitored at the frequencies specified in paragraph (f)(1) of this section, provided the operating time of all such process units is considered.

(3) The monitoring frequencies specified in paragraph (f)(1) of this section are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. An owner or operator may monitor at any time during the specified monitoring period (*e.g.,* month, quarter, year), provided the monitoring is conducted at a reasonable interval after completion of the last monitoring campaign. Reasonable intervals are defined in paragraphs (f)(3)(i) through (iv) of this section.

(i) When monitoring is conducted quarterly, monitoring events must be separated by at least 30 calendar days.

(ii) When monitoring is conducted semiannually (*i.e.,* once every 2 quarters), monitoring events must be separated by at least 60 calendar days.

(iii) When monitoring is conducted in 3 quarters per year, monitoring events must be separated by at least 90 calendar days.

(iv) When monitoring is conducted annually, monitoring events must be separated by at least 120 calendar days.

(g) The standards in §§ 60.482–1b through 60.482–11b apply at all times, including periods of startup, shutdown, and malfunction. As provided in § 60.11(f), this provision supersedes the exemptions for periods of startup, shutdown, and malfunction in the general provisions in subpart A of this part.

§ 60.482–2b Standards: Pumps in light liquid service.

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in § 60.485b(b), except as provided in § 60.482–1b(c) and (f) and paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in § 60.482–1b(c) and paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in § 60.482–1b(f).

(b)(1) The instrument reading that defines a leak is specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;

(ii) 2,000 ppm or greater for all other pumps.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable.

(i) Monitor the pump within 5 days as specified in § 60.485b(b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482–9b.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of § 60.482–10b; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.

(A) Monitor the pump within 5 days as specified in § 60.485b(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in § 60.486b(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in § 60.485b(c); and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of § 60.482–10b, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in § 60.486b(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

§ 60.482–3b Standards: Compressors.

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in § 60.482–1b(c) and paragraphs (h), (i), and (j) of this section.

(b) Each compressor seal system as required in paragraph (a) of this section shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of § 60.482–10b; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(c) The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

(d) Each barrier fluid system as described in paragraph (a) of this section shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) of this section shall be checked daily or shall be equipped with an audible alarm.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph (e)(2) of this section, a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482–9b.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(h) A compressor is exempt from the requirements of paragraphs (a) and (b) of this section, if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of § 60.482–10b, except as provided in paragraph (i) of this section.

(i) Any compressor that is designated, as described in § 60.486b(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a) through (h) of this section if the compressor:

(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in § 60.485b(c); and

(2) Is tested for compliance with paragraph (i)(1) of this section initially upon designation, annually, and at other times requested by the Administrator.

(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of § 60.14 or § 60.15 is exempt from paragraphs (a) through (e) and (h) of this section, provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of paragraphs (a) through (e) and (h) of this section.

§ 60.482–4b Standards: Pressure relief devices in gas/vapor service.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in § 60.485b(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in § 60.482–9b.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in § 60.485b(c).

(c) 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 through the pressure relief device to a control device as described in § 60.482–10b is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(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 new 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 § 60.482–9b.

§ 60.482–5b Standards: Sampling connection systems.

(a) Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in § 60.482–1b(c) and paragraph (c) of this section.

(b) Each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified in paragraphs (b)(1) through (4) of this section.

(1) Gases displaced during filling of the sample container are not required to be collected or captured.

(2) Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.

(3) Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.

(4) Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either paragraph (b)(4)(i), (ii), (iii), or (iv) of this section.

(i) Return the purged process fluid directly to the process line.

(ii) Collect and recycle the purged process fluid to a process.

(iii) Capture and transport all the purged process fluid to a control device that complies with the requirements of § 60.482–10b.

(iv) Collect, store, and transport the purged process fluid to any of the following systems or facilities:

(A) A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;

(B) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266;

(C) A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261;

(D) A waste management unit subject to and operated in compliance with the treatment requirements of 40 CFR 61.348(a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of 40 CFR 61.343 through 40 CFR 61.347; or

(E) A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR part 279, subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR part 261.

(c) In-situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

§ 60.482–6b Standards: Open-ended valves or lines.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in § 60.482–1b(c) and paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a), (b), and (c) of this section.

(e) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

§ 60.482–7b Standards: Valves in gas/vapor service and in light liquid service.

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in § 60.485b(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section, § 60.482–1b(c) and (f), and §§ 60.483–1b and 60.483–2b.

(2) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section, § 60.482–1b(c), and §§ 60.483–1b and 60.483–2b.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the existing valves in the process unit are monitored in accordance with § 60.483–1b or § 60.483–2b, count the new valve as leaking when calculating the percentage of valves leaking as described in § 60.483–2b(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

(b) If an instrument reading of 100 ppm or greater is measured, a leak is detected.

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in § 60.482–9b.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in § 60.486b(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 100 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 100 ppm above background as determined by the method specified in § 60.485b(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in § 60.486b(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in § 60.486b(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either:

(i) Becomes an affected facility through § 60.14 or § 60.15 and was constructed on or before January 5, 1981; or

(ii) Has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

§ 60.482–8b Standards: Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in § 60.485b(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482–9b.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under §§ 60.482–2b(c)(2) and 60.482–7b(e).

§ 60.482–9b Standards: Delay of repair.

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with § 60.482–10b.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) 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 next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

§ 60.482–10b Standards: Closed vent systems and control devices.

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

(d) Flares used to comply with this subpart shall comply with the requirements of § 60.18.

(e) Owners or operators of control devices used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) through (3) of this section.

(1) Conduct an initial inspection according to the procedures in § 60.485b(b); and

(2) Conduct annual inspections according to the procedures in § 60.485b(b).

(3) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(g) Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1) and (2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1) and (2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1) and (2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1) and (2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The process unit within which the closed vent system is located becomes an affected facility through §§ 60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in § 60.486b(c).

(4) For each inspection conducted in accordance with § 60.485b(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(3) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

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

§ 60.482–11b Standards: Connectors in gas/vapor service and in light liquid service.

(a) The owner or operator shall initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

(b) Except as allowed in § 60.482–1b(c), § 60.482–10b, or as specified in paragraph (e) of this section, the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in paragraphs (a) and (b)(3) of this section.

(1) The connectors shall be monitored to detect leaks by the method specified in § 60.485b(b) and, as applicable, § 60.485b(c).

(2) If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.

(3) The owner or operator shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.

(i) If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).

(ii) If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.

(iii) If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (C) of this section, as appropriate.

(A) An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.

(B) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.

(C) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

(iv) If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.

(v) The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

(c) For use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

Equation 1 to Paragraph (c)

$$\%C_L = C_L/C_t * 100$$

Where:

$\%C_L$ = Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

C_L = Number of connectors measured at 500 ppm or greater, by the method specified in § 60.485b(b).

C_t = Total number of monitored connectors in the process unit or affected facility.

(d) When a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482–9b. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.

(e) Any connector that is designated, as described in § 60.486b(f)(1), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

(1) The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and

(2) The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

(f)(1) Any connector that is inaccessible or that is ceramic or ceramic-lined (*e.g.,* porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of §§ 63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

(i) Buried;

(ii) Insulated in a manner that prevents access to the connector by a monitor probe;

(iii) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;

(iv) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;

(v) Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or

(vi) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

(2) If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

(g) Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

§ 60.483–1b Alternative standards for valves—allowable percentage of valves leaking.

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in § 60.487b(d).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it shall be repaired in accordance with § 60.482–7b(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in § 60.485b(b).

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in § 60.485b(h).

§ 60.483–2b Alternative standards for valves—skip period leak detection and repair.

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in § 60.487a(d).

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in § 60.482–7b.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in § 60.482–7b but can again elect to use this section.

(5) The percent of valves leaking shall be determined as described in § 60.485b(h).

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

(7) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with § 60.482–7b(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

§ 60.484b Equivalence of means of emission limitation.

(a) Each owner or operator subject to the provisions of this subpart may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart.

(b) Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.

(2) The Administrator will compare test data for demonstrating equivalence of the means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.

(2) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.

(3) For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(5) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (c)(4) of this section.

(6) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

(d) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(e)(1) After a request for determination of equivalence is received, the Administrator will publish a notice in the **Federal Register** and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(2) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the **Federal Register**.

(3) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the CAA.

(f)(1) Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will make an equivalence determination according to the provisions of paragraphs (b) through (e) of this section.

§ 60.485b Test methods and procedures.

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

(b) The owner or operator shall determine compliance with the standards in §§ 60.482–1b through 60.482–11b, 60.483a, and 60.484b as follows:

(1) Method 21 of appendix A–7 to this part shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(2) A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 to this part, section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in § 60.486b(e)(8). Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage.

(i) If a calibration drift assessment shows a negative drift of more than 10 percent, then all equipment with instrument readings between the appropriate leak definition and the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) that was monitored since the last calibration must be re-monitored.

(ii) If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) monitored since the last calibration may be re-monitored.

(c) The owner or operator shall determine compliance with the no-detectable-emission standards in §§ 60.482–2b(e), 60.482–3b(i), 60.482–4b, 60.482–7b(f), and 60.482–10b(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) Method 21 of appendix A–7 to this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless they demonstrate that a process unit is not in VOC service, *i.e.,* that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Procedures that conform to the general methods in ASTM E168–16 (Reapproved 2023), E169–16 (Reapproved 2022), or E260–96 (Reapproved 2019) (incorporated by reference, see § 60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F). Standard reference texts or ASTM D2879–23 (incorporated by reference, see § 60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) Method 22 of appendix A–7 to this part shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

Equation 1 to Paragraph (g)(3)

$$V_{max} = K_1 + K_2H_T$$

Where:

V_{max} = Maximum permitted velocity, m/sec (ft/sec).

H_T = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1 = 8.706 m/sec (metric units) = 28.56 ft/sec (English units).

K_2 = 0.7084 m^4/(MJ-sec) (metric units) = 0.087 ft^4/(Btu-sec) (English units).

(4) The net heating value (HT) of the gas being combusted in a flare shall be computed using the following equation:

Equation 2 to Paragraph (g)(4)

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

Where:

K = Conversion constant, 1.740×10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).

C_i = Concentration of sample component "i," ppm

H_i = net heat of combustion of sample component "i" at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole.

(5) Method 18 of appendix A–6 to this part and ASTM D1945–14 (Reapproved 2019) (incorporated by reference, see § 60.17) shall be used to determine the concentration of sample component "i." ASTM D6420–18 (incorporated by reference, see § 60.17) may be used in lieu of Method 18, under the conditions specified in paragraphs (g)(5)(i) through (iii) of this section.

(i) If the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable.

(ii) ASTM D6420–18 may not be used for methane and ethane.

(iii) ASTM D6420–18 may not be used as a total VOC method.

(6) ASTM D240–19 or D4809–18 (incorporated by reference, see § 60.17) shall be used to determine the net heat of combustion of component "i" if published values are not available or cannot be calculated.

(7) Method 2, 2A, 2C, or 2D of appendix A–7 to this part, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

(h) The owner or operator shall determine compliance with § 60.483–1b or § 60.483–2b as follows:

(1) The percent of valves leaking shall be determined using the following equation:

Equation 3 to Paragraph (h)(1)

$$\%V_L = (V_L/V_T) * 100$$

Where:

$\%V_L$ = Percent leaking valves.

V_L = Number of valves found leaking.

V_T = The sum of the total number of valves monitored.

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with § 60.482–7b(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

§ 60.486b Recordkeeping requirements.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(3) The owner or operator shall record the information specified in paragraphs (a)(3)(i) through (v) of this section for each monitoring event required by §§ 60.482–2b, 60.482–3b, 60.482–7b, 60.482–8b, 60.482–11b, and 60.483–2b.

(i) Monitoring instrument identification.

(ii) Operator identification.

(iii) Equipment identification.

(iv) Date of monitoring.

(v) Instrument reading.

(b) When each leak is detected as specified in §§ 60.482–2b, 60.482–3b, 60.482–7b, 60.482–8b, 60.482–11b, and 60.483–2b, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in § 60.482–7b(c) and no leak has been detected during those 2 months.

(3) The identification on a connector may be removed after it has been monitored as specified in § 60.482–11b(b)(3)(iv) and no leak has been detected during that monitoring.

(4) The identification on equipment, except on a valve or connector, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§ 60.482–2b, 60.482–3b, 60.482–7b, 60.482–8b, 60.482–11b, and 60.483–2b, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) Maximum instrument reading measured by Method 21 of appendix A–7 of this part at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.

(5) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in § 60.482–10b shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in § 60.482–10b(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed vent systems and control devices required in §§ 60.482–2b, 60.482–3b, 60.482–4b, and 60.482–5b are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in §§ 60.482–2b, 60.482–3b, 60.482–4b, and 60.482–5b.

(e) The following information pertaining to all equipment subject to the requirements in §§ 60.482–1b to 60.482–11b shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§ 60.482–2b(e), 60.482–3b(i), and 60.482–7b(f).

(ii) The designation of equipment as subject to the requirements of § 60.482–2b(e), § 60.482–3b(i), or § 60.482–7b(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.

(3) A list of equipment identification numbers for pressure relief devices required to comply with § 60.482–4b.

(4)(i) The dates of each compliance test as required in §§ 60.482–2b(e), 60.482–3b(i), 60.482–4b, and 60.482–7b(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(6) A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with § 60.482–1b(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

(7) The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.

(8) Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A–7 of this part and § 60.485b(b).

(i) Date of calibration and initials of operator performing the calibration.

(ii) Calibration gas cylinder identification, certification date, and certified concentration.

(iii) Instrument scale(s) used.

(iv) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A–7 of this part.

(v) Results of each calibration drift assessment required by § 60.485b(b)(2) (*i.e.,* instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

(vi) If an owner or operator makes their own calibration gas, a description of the procedure used.

(9) The connector monitoring schedule for each process unit as specified in § 60.482–11b(b)(3)(v).

(10) Records of each release from a pressure relief device subject to § 60.482–4b.

(f) The following information pertaining to all valves subject to the requirements of § 60.482–7b(g) and (h), all pumps subject to the requirements of § 60.482–2b(g), and all connectors subject to the requirements of § 60.482–11b(e) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(g) The following information shall be recorded for valves complying with § 60.483–2b:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in §§ 60.482–2b(d)(5) and 60.482–3b(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in § 60.480b(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(k) The provisions of § 60.7(b) and (d) do not apply to affected facilities subject to this subpart.

(l) Any records required to be maintained by this subpart that are submitted electronically via the EPA's 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 air agency or the EPA as part of an on-site compliance evaluation.

§ 60.487b Reporting requirements.

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date. Beginning on July 15, 2024, 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 1 year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (g) of this section. 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. All semiannual reports must include the following general information: company name, address (including county), and beginning and ending dates of the reporting period.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of § 60.482–7b, excluding those valves designated for no detectable emissions under the provisions of § 60.482–7b(f).

(3) Number of pumps subject to the requirements of § 60.482–2b, excluding those pumps designated for no detectable emissions under the provisions of § 60.482–2b(e) and those pumps complying with § 60.482–2b(f).

(4) Number of compressors subject to the requirements of § 60.482–3b, excluding those compressors designated for no detectable emissions under the provisions of § 60.482–3b(i) and those compressors complying with § 60.482–3b(h).

(5) Number of connectors subject to the requirements of § 60.482–11b.

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in § 60.486b:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in § 60.482–7b(b) or § 60.483–2b,

(ii) Number of valves for which leaks were not repaired as required in § 60.482–7b(d)(1),

(iii) Number of pumps for which leaks were detected as described in § 60.482–2b(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

(iv) Number of pumps for which leaks were not repaired as required in § 60.482–2b(c)(1) and (d)(6),

(v) Number of compressors for which leaks were detected as described in § 60.482–3b(f),

(vi) Number of compressors for which leaks were not repaired as required in § 60.482–3b(g)(1),

(vii) Number of connectors for which leaks were detected as described in § 60.482–11b(b)

(viii) Number of connectors for which leaks were not repaired as required in § 60.482–11b(d), and

(ix)–(x) [Reserved]

(xi) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) An owner or operator electing to comply with the provisions of §§ 60.483–1b or 60.483–2b shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(e) An owner or operator shall report the results of all performance tests in accordance with § 60.8. The provisions of § 60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the state. The EPA will not approve a waiver of electronic reporting to the EPA in delegating enforcement authority. Thus, electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph cannot be used to relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

(g) If you are required to submit notifications or reports following the procedure specified in this paragraph (g), you must submit notifications or 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 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 or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(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 (g).

(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. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the SOCMI NSPS 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, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the SOCMI NSPS Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(h) If you are required to electronically submit notifications or reports 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) If you are required to electronically submit notifications or reports 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.

§ 60.488b Reconstruction.

For the purposes of this subpart:

(a) The cost of the following frequently replaced components of the facility shall not be considered in calculating either the ''fixed capital cost of the new components'' or the ''fixed capital costs that would be required to construct a comparable new facility'' under § 60.15: Pump seals, nuts and bolts, rupture disks, and packings.

(b) Under § 60.15, the ''fixed capital cost of new components'' includes the fixed capital cost of all depreciable components (except components specified in § 60.488b(a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the applicability date for the appropriate subpart. (See the ''Applicability and designation of affected facility'' section of the appropriate subpart.) For purposes of this paragraph, ''commenced'' means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

§ 60.489b List of chemicals produced by affected facilities.

Process units that produce, as intermediates or final products, chemicals listed in § 60.489 are covered under this subpart. The applicability date for process units producing one or more of these chemicals is April 25, 2023.

■ 18. Revise the heading of subpart III to read as follows:

Subpart III—Standards of Performance for Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes After October 21, 1983, and on or Before April 25, 2023

■ 19. Amend § 60.610 by revising paragraph (b) introductory text and adding paragraph (e) to read as follows:

§ 60.610 Applicability and designation of affected facility.

* * * * *

(b) The affected facility is any of the following for which construction, modification, or reconstruction commenced after October 21, 1983, and on or before April 25, 2023:

* * * * *

(e) 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 this part or 40 CFR part 61 or 63, may elect to comply with the requirements in § 60.619a in lieu of all flare related requirements in any other regulation in this part or 40 CFR part 61 or 63.

■ 20. Amend § 60.611 by revising the definition of ''Flame zone'' to read as follows:

§ 60.611 Definitions.

* * * * *

Flame zone means the portion of the combustion chamber in a boiler or process heater occupied by the flame envelope.

* * * * *

■ 21. Amend § 60.613 by revising paragraphs (e)(1)(i), (e)(2)(i), and (e)(3)(i) to read as follows:

§ 60.613 Monitoring of emissions and operations.

* * * * *

(e) * * *

(1) * * *

(i) A scrubbing liquid temperature monitoring device having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or 0.5 °C, whichever is greater, and a specific gravity monitoring device having an accuracy of 0.02 specific gravity units, each equipped with a continuous recorder; or

* * * * *

(2) * * *

(i) A condenser exit (product side) temperature monitoring device equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or 0.5 °C, whichever is greater; or

* * * * *

(3) * * *

(i) An integrating steam flow monitoring device having an accuracy of 10 percent, and a carbon bed temperature monitoring device having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater, both equipped with a continuous recorder; or

* * * * *

■ 22. Amend § 60.614 by revising paragraphs (b)(4) introductory text and (e) to read as follows:

§ 60.614 Test methods and procedures.

* * * * *

(b) * * *

(4) Method 18 of appendix A–6 to this part to determine concentration of TOC in the control device outlet and the concentration of TOC in the inlet when the reduction efficiency of the control device is to be determined. ASTM D6420–18 (incorporated by reference, see § 60.17) 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 may not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method.

* * * * *

(e) The following test methods, except as provided under § 60.8(b), shall be used for determining the net heating value of the gas combusted to determine compliance under § 60.612(b) and for determining the process vent stream TRE index value to determine compliance under § 60.612(c).

(1)(i) Method 1 or 1A of appendix A–1 to this part, as appropriate, for selection of the sampling site. The sampling site for the vent stream flow rate and molar composition determination prescribed in § 60.614(e)(2) and (3) shall be, except for the situations outlined in paragraph (e)(1)(ii) of this section, prior to the inlet of any control device, prior to any post-reactor dilution of the stream with air, and prior to any post-reactor introduction of halogenated compounds into the vent stream. No transverse site selection method is needed for vents smaller than 10 centimeters (4 inches) in diameter.

(ii) If any gas stream other than the air oxidation vent stream from the affected facility is normally conducted through the final recovery device.

(A) The sampling site for vent stream flow rate and molar composition shall be prior to the final recovery device and prior to the point at which the nonair oxidation stream is introduced.

(B) The efficiency of the final recovery device is determined by measuring the TOC concentration using Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in paragraph (b)(4) of this section, at the inlet to the final recovery device after the introduction of any nonair oxidation vent stream and at the outlet of the final recovery device.

(C) This efficiency is applied to the TOC concentration measured prior to the final recovery device and prior to the introduction of the nonair oxidation stream to determine the concentration of TOC in the air oxidation stream from the final recovery device. This concentration of TOC is then used to perform the calculations outlined in § 60.614(e)(4) and (5).

(2) The molar composition of the process vent stream shall be determined as follows:

(i) Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in paragraph (b)(4) of this section, to measure the concentration of TOC including those containing halogens.

(ii) D1946–77 or 90 (Reapproved 1994) (incorporation by reference, see § 60.17) to measure the concentration of carbon monoxide and hydrogen.

(iii) Method 4 of appendix A to this part to measure the content of water vapor.

(3) The volumetric flow rate shall be determined using Method 2, 2A, 2C, or 2D of appendix A–1 to this part, as appropriate.

(4) The net heating value of the vent stream shall be calculated using the following equation:

Equation 6 to Paragraph (e)(4)

$$H_T = K_1 \left(\sum_{j=1}^{n} C_j H_j \right)$$

Where:

H_T = Net heating value of the sample, MJ/scm (Btu/scf), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg (77 °F and 30 in. Hg), but the standard temperature for determining the volume corresponding to one mole is 20 °C (68 °F).

K_1 = 1.74×10^{-7} (1/ppm)(g-mole/scm)(MJ/kcal) (metric units), where standard temperature for (g-mole/scm) is 20 °C.

= 1.03×10^{-11} (1/ppm)(lb-mole/scf)(Btu/kcal) (English units) where standard temperature for (lb/mole/scf) is 68 °F.

C_j = Concentration on a wet basis of compound j in ppm, as measured for organics by Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in paragraph (b)(4) of this section, and measured for hydrogen and carbon monoxide by ASTM D1946–77, 90, or 94 (incorporation by reference, see § 60.17) as indicated in paragraph (e)(2) of this section.

H_j = Net heat of combustion of compound j, kcal/(g-mole) [kcal/(lb-mole)], based on combustion at 25 °C and 760 mm Hg (77 °F and 30 in. Hg).

(5) The emission rate of TOC in the process vent stream shall be calculated using the following equation:

Equation 7 to Paragraph (e)(5)

$$E_{TOC} = K_2 \left[\sum_{j=1}^{n} C_j M_j \right] Q_s$$

Where:

E_{TOC} = Measured emission rate of TOC, kg/hr (lb/hr).

K_2 = 2.494×10^{-6} (1/ppm)(g-mole/scm)(kg/g)(min/hr) (metric units), where standard temperature for (g-mole/scm) is 20 °C.

= 1.557×10^{-7} (1/ppm)(lb-mole/scf)(min/hr) (English units), where standard temperature for (lb-mole/scf) is 68 °F.

C_j = Concentration on a wet basis of compound j in ppm, as measured by Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in paragraph (b)(4) of this section, as indicated in paragraph (e)(2) of this section.

M_j = Molecular weight of sample j, g/g-mole (lb/lb-mole).

Q_s = Vent stream flow rate, scm/hr (scf/hr), at a temperature of 20 °C (68 °F).

(6) The total process vent stream concentration (by volume) of compounds containing halogens (ppmv, by compound) shall be summed from the individual concentrations of compounds containing halogens which were measured by Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference,

see § 60.17) as specified in paragraph (b)(4) of this section.

* * * * *

■ 23. Amend § 60.615 by revising paragraphs (b) introductory text, (j) introductory text, and (k) and adding paragraphs (m), (n), and (o) to read as follows:

§ 60.615 Reporting and recordkeeping requirements.

* * * * *

(b) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible records of the following data measured during each performance test, and also include the following data in the report of the initial performance test required under § 60.8. Where a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to comply with § 60.612(a), a report containing performance test data need not be submitted, but a report containing the information of § 60.615(b)(2)(i) is required. The same data specified in this section shall be submitted in the reports of all subsequently required performance tests where either the emission control efficiency of a control device, outlet concentration of TOC, or the TRE index value of a vent stream from a recovery system is determined. Beginning on July 15, 2024, owners and operators must submit the performance test report following the procedures specified in paragraph (m) of this section. Data collected using test methods that are 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, the owner or operator 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 an alternate electronic file.

* * * * *

(j) Each owner or operator that seeks to comply with the requirements of this subpart by complying with the requirements of § 60.612 shall submit to the Administrator semiannual reports of the following information. The initial report shall be submitted within 6 months after the initial start-up-date. On and after July 15, 2025 or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for 1 year, whichever date is later, owners and operators must submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (m) of this section. 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.

* * * * *

(k) The requirements of § 60.615(j) remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with § 60.615(j), provided that they comply with the requirements established by the State. The EPA will not approve a waiver of electronic reporting to the EPA in delegating enforcement authority. Thus, electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph cannot be used to relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

* * * * *

(m) If an owner or operator is required to submit notifications or reports following the procedure specified in this paragraph (m), the owner or operator must submit notifications or 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 the owner or operator. Do not use CEDRI to submit information the owner or operator claims as CBI. Although the EPA does not expect persons to assert a claim of CBI, if an owner or operator wishes to assert a CBI claim for some of the information in the report or notification, the owner or operator must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (m)(1) and (2) of this section. Clearly mark the part or all of the information claimed 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. The owner or operator 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 (m).

(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. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the SOCMI NSPS Sector Lead. Owners and operators who do not have their own file sharing service and who require assistance with submitting large electronic files that exceed the file size limit for email attachments should email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If an owner or operator cannot transmit the file electronically, the owner or operator may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the SOCMI NSPS Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(n) Owners and operators required to electronically submit notifications or reports through CEDRI in the EPA's CDX may assert a claim of EPA system outage for failure to timely comply with the electronic submittal requirement. To assert a claim of EPA system outage, owners and operators must meet the requirements outlined in paragraphs (n)(1) through (7) of this section.

(1) The owner or operator 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) The owner or operator must submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) The owner or operator 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 the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the report was submitted.

(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.

(o) Owners and operators required to electronically submit notifications or reports through CEDRI in the EPA's CDX, owners and operators may assert a claim of *force majeure* for failure to timely comply with the electronic submittal requirement. To assert a claim of *force majeure,* you must meet the requirements outlined in paragraphs (o)(1) through (5) of this section.

(1) An owner or operator 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 the owner or operator 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) The owner or operator must submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) The owner or operator 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 the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the report was submitted.

(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.

■ 24. Amend § 60.618 by revising paragraph (b) to read as follows:

§ 60.618 Delegation of authority.

* * * * *

(b) Authorities which will not be delegated to States: § 60.613(e) and approval of an alternative to any electronic reporting to the EPA required by this subpart.

■ 25. Add subpart IIIa to read as follows:

Subpart IIIa—Standards of Performance for Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes for Which Construction, Reconstruction, or Modification Commenced After April 25, 2023

Sec.

Subpart IIIa—Standards of Performance for Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes for Which Construction, Reconstruction, or Modification Commenced After April 25, 2023

§ 60.610a Am I subject to this subpart?

(a) You are subject to this subpart if you operate an affected facility designated in paragraph (b) of this section that produces any of the chemicals listed in § 60.617a as a product, co-product, by-product, or intermediate, except as provided in paragraph (c) of this section.

(b) The affected facility is any of the following for which construction, modification, or reconstruction commenced after April 25, 2023:

(1) Each air oxidation reactor not discharging its vent stream into a recovery system.

(2) Each combination of an air oxidation reactor and the recovery system into which its vent stream is discharged.

(3) Each combination of two or more air oxidation reactors and the common recovery system into which their vent streams are discharged.

(c) Exemptions from the provisions of paragraph (a) of this section are as follows:

(1) Each affected facility operated with a vent stream flow rate less than

0.001 pound per hour (lb/hr) of TOC is exempt from all provisions of this subpart except for the test method and procedure and the recordkeeping and reporting requirements in § 60.614a(e) and § 60.615a(h), (i)(8), and (n).

(2) A vent stream going to a fuel gas system as defined in § 63.611a.

§ 60.611a What definitions must I know?

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

Air Oxidation Reactor means any device or process vessel in which one or more organic reactants are combined with air, or a combination of air and oxygen, to produce one or more organic compounds. Ammoxidation and oxychlorination reactions are included in this definition.

Air Oxidation Reactor Recovery Train means an individual recovery system receiving the vent stream from at least one air oxidation reactor, along with all air oxidation reactors feeding vent streams into this system.

Air Oxidation Unit Process means a unit process, including ammoxidation and oxychlorination unit process, that uses air, or a combination of air and oxygen, as an oxygen source in combination with one or more organic reactants to produce one or more organic compounds.

Boilers means any enclosed combustion device that extracts useful energy in the form of steam.

Breakthrough means the time when the level of 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.

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.

Continuous recorder means a data recording device recording an instantaneous data value at least once every 15 minutes.

Flame zone means the portion of the combustion chamber in a boiler or process heater occupied by the flame envelope.

Flow indicator means a device which indicates whether gas flow is present in a vent stream.

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.

Halogenated vent stream means any vent stream determined to have a total concentration (by volume) of compounds containing halogens of 20 ppmv (by compound) or greater.

Incinerator means any enclosed combustion device that is used for destroying organic compounds and does not extract energy in the form of steam or process heat.

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.

Primary fuel means the fuel fired through a burner or a number of similar burners. The primary fuel provides the principal heat input to the device, and the amount of fuel is sufficient to sustain operation without the addition of other fuels.

Process heater means a device that transfers heat liberated by burning fuel to fluids contained in tubes, including all fluids except water that is heated to produce steam.

Process unit means equipment assembled and connected by pipes or ducts to produce, as intermediates or final products, one or more of the chemicals in § 60.617a. A process unit can operate independently if supplied with sufficient fuel or raw materials and sufficient product storage facilities.

Product means any compound or chemical listed in § 60.617a that is produced for sale as a final product as that chemical or is produced for use in a process that needs that chemical for the production of other chemicals in another facility. By-products, co-products, and intermediates are considered to be products.

Recovery device means an individual unit of equipment, such as an absorber, condenser, and carbon adsorber, capable of and used to recover chemicals for use, reuse, or sale.

Recovery system means an individual recovery device or series of such devices applied to the same process stream.

Relief valve means a valve used only to release an unplanned, nonroutine discharge. A relief valve discharge results from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause that requires immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage.

Total organic compounds (TOC) means those compounds measured according to the procedures of Method 18 of appendix A–6 to this part or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in § 60.614a(b)(4) or the concentration of organic compounds measured according to the procedures in Method 21 or Method 25A of appendix A–7 to this part.

Vent stream means any gas stream, containing nitrogen which was introduced as air to the air oxidation reactor, released to the atmosphere directly from any air oxidation reactor recovery train or indirectly, after diversion through other process equipment. The vent stream excludes equipment leaks including, but not limited to, pumps, compressors, and valves.

§ 60.612a What standards and associated requirements must I meet?

(a) You must comply with the emission limits and standards specified in Table 1 to this subpart and the requirements specified paragraphs (b) and (c) of this section for each vent stream on and after the date on which the initial performance test required by §§ 60.8 and 60.614a is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after the initial start-up, whichever date comes first. The standards in this section apply at all times, including periods of startup, shutdown and malfunction. As provided in § 60.11(f), this provision supersedes the exemptions for periods of startup, shutdown and malfunction in the general provisions in subpart A of this part.

(b) The following release events from an affected facility are a violation of the emission limits and standards specified in table 1 to this subpart.

(1) Any relief valve discharge to the atmosphere of a vent stream.

(2) The use of a bypass line at any time on a closed vent system to divert emissions to the atmosphere, or to a control device or recovery device not

meeting the requirements specified in § 60.613a.

(c) You may designate a vent stream 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. You must comply with the applicable requirements in paragraphs (c)(1) through (3) of this section for each maintenance vent. Any vent stream designated as a maintenance vent is only subject to the maintenance vent provisions in this paragraph (c) and the associated recordkeeping and reporting requirements in § 60.615a(g), respectively.

(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 § 60.619a, as applicable, or using any combination of a non-flare control device or recovery device meeting the requirements in Table 1 to this subpart until one of the following conditions, as applicable, is met.

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

(ii) If there is no ability to measure the LEL of the vapor in the equipment based on the design of the equipment, the pressure in the equipment served by the maintenance vent is reduced to 5 pounds per square inch gauge (psig) or less. Upon opening the maintenance vent, active purging of the equipment cannot be used until the LEL of the vapors in the maintenance vent (or inside the equipment if the maintenance is a hatch or similar type of opening) is less than 10 percent.

(iii) The equipment served by the maintenance vent contains less than 50 pounds of total VOC.

(iv) 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 (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 (c)(1)(iii) of this section, you must determine the LEL or, if applicable, equipment pressure using process instrumentation or portable measurement devices and follow procedures for calibration and maintenance according to manufacturer's specifications.

(3) For maintenance vents complying with the alternative in paragraph (c)(1)(iii) of this section, you 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.

§ 60.613a What are my monitoring, installation, operation, and maintenance requirements?

(a) Except as specified in paragraphs (a)(5) through (7) of this section, if you use a non-flare control device or recovery system to comply with the TOC emission limit specified in Table 1 to this subpart, then you must comply with paragraphs (a)(1) through (4), (b), and (c) of this section.

(1) Install a continuous parameter monitoring system(s) (CPMS) and monitor the operating parameter(s) applicable to the control device or recovery system as specified in Table 2 to this subpart or established according to paragraph (c) of this section.

(2) Establish the applicable minimum, maximum, or range for the operating parameter limit as specified in Table 3 to this subpart or established according to paragraph (c) of this section by calculating the value(s) as the arithmetic average of operating parameter measurements recorded during the three test runs conducted for the most recent performance test. You may operate outside of the established operating parameter limit(s) during subsequent performance tests in order to establish new operating limits. You must include the updated operating limits with the performance test results submitted to the Administrator pursuant to § 60.615a(b). Upon establishment of a new operating limit, you must thereafter operate under the new operating limit. If the Administrator determines that you did not conduct the performance test in accordance with the applicable requirements or that the operating limit established during the performance test does not correspond to the conditions specified in § 60.614a(a), then you must conduct a new performance test and establish a new operating limit.

(3) Monitor, record, and demonstrate continuous compliance using the minimum frequencies specified in Table 3 to this subpart or established according to paragraph (c) of this section.

(4) Comply with the calibration and quality control requirements as specified in Table 4 to this subpart or established according to paragraph (c) of this section that are applicable to the CPMS used.

(5) Any vent stream introduced with primary fuel into a boiler or process heater is exempt from the requirements specified in paragraphs (a)(1) through (4) of this section.

(6) If you vent 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 install a system of two or more adsorber units in series and comply with the requirements specified in paragraphs (a)(6)(i) through (iii) of this section in addition to the requirements specified in paragraphs (a)(1) through (4) 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 TOC concentration through a sample port at the outlet of the first adsorber bed in series according to the schedule in paragraph (a)(6)(iii)(B) of this section. You must measure the concentration of TOC using either a portable analyzer, in accordance with Method 21 of appendix A–7 of this part using methane, propane, or isobutylene as the calibration gas or Method 25A of appendix A–7 of this part using methane or propane as the calibration gas.

(iii) Comply with paragraph (a)(6)(iii)(A) of this section, and comply with the monitoring frequency according to paragraph (a)(6)(iii)(B) of this section.

(A) The first adsorber in series must be replaced immediately when breakthrough, as defined in § 60.611a, 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 (a)(6)(iii)(A), "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. You 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)(6)(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.

(7) If you install a continuous emissions monitoring system (CEMS) to demonstrate compliance with the TOC standard in Table 1 of this subpart, you must comply with the requirements specified in § 60.614a(f) in lieu of the requirements specified in paragraphs (a)(1) through (4) and (c) of this section.

(b) If you vent emissions through a closed vent system to a boiler or process heater, then the vent stream must be introduced into the flame zone of the boiler or process heater.

(c) If you seek to demonstrate compliance with the standards specified under § 60.612a with control devices other than an incinerator, boiler, process heater, or flare; or recovery devices other than an absorber, condenser, or carbon adsorber, you shall provide to the Administrator prior to conducting the initial performance test information describing the operation of the control device or recovery device and the parameter(s) which would indicate proper operation and maintenance of the device and how the parameter(s) are indicative of control of TOC emissions. The Administrator may request further information and will specify appropriate monitoring procedures or requirements, including operating parameters to be monitored, averaging times for determining compliance with the operating parameter limits, and ongoing calibration and quality control requirements.

§ 60.614a What test methods and procedures must I use to determine compliance with the standards?

(a) For the purpose of demonstrating compliance with the emission limits and standards specified in table 1 to this subpart, all affected facilities must be run at full operating conditions and flow rates during any performance test. Performance tests are not required if you determine compliance using a CEMS that meets the requirements outlined in paragraph (f) of this section.

(1) Conduct initial performance tests no later than the date required by § 60.8(a).

(2) Conduct subsequent performance tests no later than 60 calendar months after the previous performance test.

(b) The following methods, except as provided in § 60.8(b) must be used as reference methods to determine compliance with the emission limit or percent reduction efficiency specified in table 1 to this subpart for non-flare control devices and/or recovery systems.

(1) Method 1 or 1A of appendix A–1 to this part, as appropriate, for selection of the sampling sites. The inlet sampling site for determination of vent stream molar composition or TOC (less methane and ethane) reduction efficiency shall be prior to the inlet of the control device or, if equipped with a recovery system, then prior to the inlet of the first recovery device in the recovery system.

(2) Method 2, 2A, 2C, or 2D of appendix A–1 to this part, as appropriate, for determination of the volumetric flow rates.

(3) Method 3A of appendix A–2 to this part or the manual method in ANSI/ASME PTC 19.10–1981 (incorporated by reference, see § 60.17) must be used to determine the oxygen concentration (%O2d) for the purposes of determining compliance with the 20 ppmv limit. The sampling site must be the same as that of the TOC samples and the samples must be taken during the same time that the TOC samples are taken. The TOC concentration corrected to 3 percent O_2 (C_c) must be computed using the following equation:

Equation 1 to Paragraph (b)(3)

$$C_c = C_{TOC} \frac{17.9}{20.9 - \%O_{2d}}$$

Where:

C_c = Concentration of TOC corrected to 3 percent O_2, dry basis, ppm by volume.

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

$\%O_{2d}$ = Concentration of O_2, dry basis, percent by volume.

(4) Method 18 of appendix A–6 to this part to determine concentration of TOC in the control device outlet or in the outlet of the final recovery device in a recovery system, and to determine the concentration of TOC in the inlet when the reduction efficiency of the control device or recovery system is to be determined. ASTM D6420–18 (incorporated by reference, see § 60.17) 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.

(i) The sampling time for each run must be 1 hour in which either an integrated sample or at least four grab samples must be taken. If grab sampling is used then the samples must be taken at 15-minute intervals.

(ii) The emission reduction (R) of TOC (minus methane and ethane) must be determined using the following equation:

Equation 2 to Paragraph (b)(4)(ii)

$$R = \frac{E_i - E_o}{E_i} \times 100$$

Where:

R = Emission reduction, percent by weight.

E_i = Mass rate of TOC entering the control device or recovery system, kg/hr (lb/hr).

E_o = Mass rate of TOC discharged to the atmosphere, kg/hr (lb/hr).

(iii) The mass rates of TOC (E_i, E_o) must be computed using the following equations:

Equations 3 and 4 to Paragraph (b)(4)(iii)

$$E_i = K_2\left(\sum_{j=1}^{n} C_{ij} M_{ij}\right) Q_i$$

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj} M_{oj}\right) Q_o$$

Where:

C_{ij}, C_{oj} = Concentration of sample component "j" of the gas stream at the inlet and outlet of the control device or recovery system, respectively, dry basis ppm by volume.

M_{ij}, M_{oj} = Molecular weight of sample component "j" of the gas stream at the inlet and outlet of the control device or recovery system, respectively, g/g-mole (lb/lb-mole).

Q_i, Q_o = Flow rate of gas stream at the inlet and outlet of the control device or recovery system, respectively, dscm/min (dscf/min).

K_2 = 2.494×10^{-6} (1/ppm)(g-mole/scm)(kg/g)(min/hr) (metric units), where standard temperature for (g-mole/scm) is 20 °C.

= 1.557×10^{-7} (1/ppm)(lb-mole/scf)(min/hr) (English units), where standard temperature for (lb-mole/scf) is 68 °F.

(iv) The TOC concentration (C_{TOC}) is the sum of the individual components and must be computed for each run using the following equation:

Equation 5 to Paragraph (b)(4)(iv)

$$C_{TOC} = \sum_{j=1}^{n} C_j$$

Where:

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

C_j = Concentration of sample components in the sample.

n = Number of components in the sample.

(c) The requirement for initial and subsequent performance tests are waived, in accordance with § 60.8(b), for the following:

(1) When a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to seek compliance with the emission limit or percent reduction efficiency specified in table 1 to this subpart.

(2) When a vent stream is introduced into a boiler or process heater with the primary fuel.

(3) 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 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 40 CFR 63.1207(j) and complies with the requirements of 40 CFR part 63, subpart EEE; or

(iv) Complies with 40 CFR part 63, subpart EEE and will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date the owner or operator would have been required to submit the initial performance test report for this subpart.

(4) The Administrator reserves the option to require testing at such other times as may be required, as provided for in section 114 of the Act.

(d) For purposes of complying with the 98 weight-percent reduction in § 60.612a(a), if the vent stream entering a boiler or process heater with a design capacity less than 44 MW (150 million Btu/hour) is introduced with the combustion air or as secondary fuel, the weight-percent reduction of TOC (minus methane and ethane) across the combustion device shall be determined by comparing the TOC (minus methane and ethane) in all combusted vent streams, primary fuels, and secondary fuels with the TOC (minus methane and ethane) exiting the combustion device.

(e) Any owner or operator subject to the provisions of this subpart seeking to demonstrate compliance with § 60.610a(c)(1) must use the following methods:

(1) Method 1 or 1A of appendix A–1 to this part, as appropriate.

(2) Method 2, 2A, 2C, or 2D of appendix A–1 to this part, as appropriate, for determination of the gas volumetric flow rates.

(3) Method 18 of appendix A–6 to this part to determine the concentration of TOC. ASTM D6420–18 (incorporated by reference, see § 60.17) 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 may not be used for methane and ethane; and ASTM D6420–18 must not be used as a total VOC method.

(i) The sampling site must be at a location that provides a representative sample of the vent stream.

(ii) Perform three test runs. The sampling time for each run must be 1 hour in which either an integrated sample or at least four grab samples must be taken. If grab sampling is used then the samples must be taken at 15-minute intervals.

(iii) The mass rate of TOC (E) must be computed using the following equation:

Equation 6 to Paragraph (e)(3)(ii)

$$E = K\left(\sum_{j=1}^{n} C_j M_j\right) Q$$

Where:

C_j = Concentration of sample component "j" of the gas stream at the representative sampling location, dry basis, ppm by volume.

M_j = Molecular weight of sample component "j" of the gas stream at the representative sampling location, g/g-mole (lb/lb-mole).

Q = Flow rate of gas stream at the representative sampling location, dscm/min (dscf/min).

K = 2.494×10^{-6} (1/ppm)(g-mole/scm) (kg/g) (min/hr) (metric units), where standard temperature for (g-mole/scm) is 20 °C.

= 1.557×10^{-7} (1/ppm) (lb-mole/scf) (min/hr) (English units), where standard temperature for (lb-mole/scf) is 68 °F.

(f) If you use a CEMS to demonstrate initial and continuous compliance with the TOC standard in table 1 of this subpart, each CEMS must be installed, operated and maintained according to the requirements in § 60.13 and paragraphs (f)(1) through (5) of this section.

(1) You must use a CEMS that is capable of measuring the target analyte(s) as demonstrated using either process knowledge of the control device inlet stream or the screening procedures of Method 18 of appendix A–6 to this part on the control device inlet stream. If your CEMS is located after a combustion device and inlet stream to that device includes methanol or formaldehyde, you must use a CEMS which meets the requirements in Performance Specification 9 or 15 of appendix B to this part.

(2) Each CEMS must be installed, operated, and maintained according to the applicable performance specification of appendix B to this part and the applicable quality assurance procedures of appendix F to this part. Locate the sampling probe or other interface at a measurement location such that you obtain representative measurements of emissions from the affected facility.

(3) Conduct a performance evaluation of each CEMS within 180 days of installation of the monitoring system. Conduct subsequent performance evaluations of the CEMS no later than 12 calendar months after the previous performance evaluation. The results each performance evaluation must be submitted in accordance with § 60.615a(b)(1).

(4) You must determine TOC concentration according to one of the following options. The span value of the TOC CEMS must be approximately 2 times the emission standard specified in table 1 of this subpart.

(i) For CEMS meeting the requirements of Performance Specification 15 of appendix B to this part, determine the target analyte(s) for calibration using either process knowledge of the control device inlet stream or the screening procedures of Method 18 of appendix A–6 to this part on the control device inlet stream. The individual analytes used to quantify TOC must represent 98 percent of the expected mass of TOC present in the stream. Report the results of TOC as equivalent to carbon (C1).

(ii) For CEMS meeting the requirements of Performance Specification 9 of appendix B to this part, determine the target analyte(s) for calibration using either process knowledge of the control device inlet stream or the screening procedures of Method 18 of appendix A–6 to this part on the control device inlet stream. The individual analytes used to quantify TOC must represent 98 percent of the expected mass of TOC present in the stream. Report the results of TOC as equivalent to carbon (C1).

(iii) For CEMS meeting the requirements of Performance Specification 8 of appendix B to this part used to monitor performance of a combustion device, calibrate the instrument on the predominant organic HAP and report the results as carbon (C1), and use Method 25A of appendix A–7 to this part as the reference method for the relative accuracy tests. You must also comply with procedure 1 of appendix F to this part.

(iv) For CEMS meeting the requirements of Performance Specification 8 of appendix B to this part used to monitor performance of a noncombustion device, determine the predominant organic compound using either process knowledge or the screening procedures of Method 18 of appendix A–6 to this part on the control device inlet stream. Calibrate the monitor on the predominant organic compound and report the results as C_1. Use Method 25A of appendix A–7 to this part as the reference method for the relative accuracy tests. You must also comply with procedure 1 of appendix F to this part.

(5) You must determine stack oxygen concentration at the same location where you monitor TOC concentration with a CEMS that meets the requirements of Performance Specification 3 of appendix B to this part. The span value of the oxygen CEMS must be approximately 25 percent oxygen. Use Method 3A of appendix A–2 to this part as the reference method for the relative accuracy tests.

(6) You must maintain written procedures for your CEMS. At a minimum, the procedures must include the information in paragraphs (f)(6)(i) through (vi) of this section:

(i) Description of CEMS installation location.

(ii) Description of the monitoring equipment, including the manufacturer and model number for all monitoring equipment components and the span of the analyzer.

(iii) Routine quality control and assurance procedures.

(iv) Conditions that would trigger a CEMS performance evaluation, which must include, at a minimum, a newly installed CEMS; a process change that is expected to affect the performance of the CEMS; and the Administrator's request for a performance evaluation under section 114 of the Clean Air Act.

(v) Ongoing operation and maintenance procedures.

(vi) Ongoing recordkeeping and reporting procedures.

§ 60.615a What records must I keep and what reports must I submit?

(a) You must notify the Administrator of the specific provisions of table 1 to this subpart or § 60.612a(c) with which you have elected to comply. Notification must be submitted with the notification of initial start-up required by § 60.7(a)(3). If you elect at a later date to use an alternative provision of table 1 to this subpart with which you will comply, then you must notify the Administrator 90 days before implementing a change and, upon implementing the change, you must conduct a performance test as specified by § 60.614a within 180 days.

(b) If you use a non-flare control device or recovery system to comply with the TOC emission limit specified in table 1 to this subpart, then you must keep up-to-date, readily accessible records of the data measured during each performance test to show compliance with the TOC emission limit. You must also include all of the data you use to comply with § 60.613a(a)(2). The same data specified in this paragraph must also be submitted in the initial performance test required in § 60.8 and the reports of all subsequently required performance tests where either the emission reduction efficiency of a control device or recovery system or outlet concentration of TOC is determined. Alternatively, you must keep records of each CEMS performance evaluation.

(1) Within 60 days after the date of completing each performance test or CEMS performance evaluation required by this subpart, you must submit the results of the performance test or performance evaluation following the procedures specified in paragraph (j) of this section. Data collected using test methods and performance evaluations of CEMS measuring relative accuracy test audit (RATA) pollutants 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 or performance evaluation 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 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.

(2) If you use a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater to comply with the TOC emission limit specified in Table 1 to this subpart, then you are not required to submit a report containing performance test data; however, you must submit a description of the location at which the vent stream is introduced into the boiler or process heater.

(c) If you use a non-flare control device or recovery system to comply with the TOC emission limit specified in table 1 to this subpart, then you must keep up-to-date, readily accessible records of periods of operation during which the operating parameter limits established during the most recent performance test are exceeded or periods of operation where the TOC CEMS, averaged on a 3-hour block basis, indicate an exceedance of the emission standard in table 1 of this subpart. Additionally, you must record all periods when the TOC CEMS is inoperable. The Administrator may at any time require a report of these data. Periods of operation during which the operating parameter limits established during the most recent performance tests are exceeded are defined as follows:

(1) For absorbers:

(i) All 3-hour periods of operation during which the average absorbing liquid temperature was above the maximum absorbing liquid temperature established during the most recent performance test.

(ii) All 3-hour periods of operation during which the average absorbing liquid specific gravity was outside the exit specific gravity range (*i.e.,* more than 0.1 unit above, or more than 0.1 unit below, the average absorbing liquid specific gravity) established during the most recent performance test.

(2) For boilers or process heaters:

(i) Whenever there is a change in the location at which the vent stream is introduced into the flame zone as required under § 60.613a(b).

(ii) If the boiler or process heater has a design heat input capacity of less than 44 MW (150 million Btu/hr), then all 3-hour periods of operation during which the average firebox temperature was below the minimum firebox temperature during the most recent performance test.

(3) For catalytic incinerators:

(i) All 3-hour periods of operation during which the average temperature of the vent stream immediately before the catalyst bed is below the minimum temperature of the vent stream established during the most recent performance test.

(ii) All 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than the average temperature difference of the device established during the most recent performance test.

(4) For carbon adsorbers:

(i) All carbon bed regeneration cycles during which the total mass stream flow or the total volumetric stream flow was below the minimum flow established during the most recent performance test.

(ii) All carbon bed regeneration cycles during which the temperature of the carbon bed after regeneration (and after completion of any cooling cycle(s)) was greater than the maximum carbon bed temperature (in degrees Celsius) established during the most recent performance test.

(5) For condensers, all 3-hour periods of operation during which the average exit (product side) condenser operating temperature was above the maximum exit (product side) operating temperature established during the most recent performance test.

(6) For scrubbers used to control halogenated vent streams:

(i) All 3-hour periods of operation during which the average pH of the scrubber effluent is below the minimum pH of the scrubber effluent established during the most recent performance test.

(ii) All 3-hour periods of operation during which the average influent liquid flow to the scrubber is below the minimum influent liquid flow to the scrubber established during the most recent performance test.

(iii) All 3-hour periods of operation during which the average liquid-to-gas ratio flow of the scrubber is below the minimum liquid-to-gas ratio of the scrubber established during the most recent performance test.

(7) For thermal incinerators, all 3-hour periods of operation during which the average firebox temperature was below the minimum firebox temperature established during the most recent performance test.

(8) For all other control devices, all periods (for the averaging time specified by the Administrator) when the operating parameter(s) established under § 60.613a(c) exceeded the operating limit established during the most recent performance test.

(d) You must keep up-to-date, readily accessible continuous records of the flow indication specified in Table 2 to this subpart, as well as up-to-date, readily accessible records of all periods when the vent stream is diverted from the control device or recovery device or has no flow rate, including the records as specified in paragraphs (d)(1) and (2) of this section.

(1) For each flow event from a relief valve discharge subject to the requirements in § 60.612a(b)(1), you must include an estimate of the volume of gas, the concentration of TOC in the gas and the resulting emissions of TOC that released to the atmosphere using process knowledge and engineering estimates.

(2) For each flow event from a bypass line subject to the requirements in §§ 60.612a(b)(2) and 60.620a(e), you 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 or recovery device not meeting the requirements in this subpart, you must include an estimate of the volume of gas, the concentration of TOC in the gas and the resulting emissions of TOC that bypassed the control device or recovery device using process knowledge and engineering estimates.

(e) If you use a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater to comply with the TOC emission limit specified in Table 1 to this subpart, then you must keep an up-to-date, readily accessible record of all periods of operation of the boiler or process heater. (Examples of such records could include records of steam use, fuel use, or monitoring data collected pursuant to other State or Federal regulatory requirements).

(f) If you use a flare to comply with the TOC emission standard specified in Table 1 to this subpart, then you must keep up-to-date, readily accessible records of 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 this chapter, as applicable; and all periods during the compliance determination when the pilot flame or flare flame is absent.

(g) For each maintenance vent opening subject to the requirements of § 60.612a(c), you must keep the applicable records specified in paragraphs (g)(1) through (5) of this section.

(1) You 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 § 60.612a(c). 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 § 60.612a(c)(1)(i), and the lower explosive limit at the time of the vessel opening exceeds 10 percent, identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, and the lower explosive limit at the time of the vessel opening.

(3) If complying with the requirements of § 60.612a(c)(1)(ii), and either the vessel pressure at the time of the vessel opening exceeds 5 psig or the lower explosive limit at the time of the active purging was initiated exceeds 10 percent, identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, the pressure of the vessel or equipment at the time of discharge to the atmosphere and, if applicable, the lower explosive limit of the vapors in the equipment when active purging was initiated.

(4) If complying with the requirements of § 60.612a(c)(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 (g)(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 (g)(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 § 60.612a(c)(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 lower explosive limit 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.

(h) If you seek to comply with the requirements of this subpart by complying with the flow rate cutoff in § 60.610a(c)(1) you must keep up-to-date, readily accessible records to indicate that the vent stream flow rate is less than 0.001 lb/hr, and of any change in equipment or process operation that increases the operating vent stream flow rate, including a measurement of the new vent stream flow rate.

(i) You must submit to the Administrator semiannual reports of the information specified in paragraphs (i)(1) through (7) of this section. You are exempt from the reporting requirements specified in § 60.7(c). If there are no exceedances, periods, or events specified in paragraphs (i)(1) through (7) of this section that occurred during the reporting period, then you must include a statement in your report that no exceedances, periods, and events specified in paragraphs (i)(1) through (7) of this section occurred during the reporting period. The initial report must be submitted within 6 months after the initial start-up-date. On and after July 15, 2024 or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for 1 year, whichever date is later, you must submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (j) of this section. 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. All semiannual reports must include the following general information: company name, address (including county), and beginning and ending dates of the reporting period.

(1) Exceedances of monitored parameters recorded under paragraph (c) of this section. For each exceedance, the report must include a list of the affected facilities or equipment, the monitored parameter that was exceeded, the start date and time of the exceedance, the duration (in hours) of the exceedance, 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 exceedance (including unknown cause, if applicable), as applicable, and the corrective action taken.

(2) All periods recorded under paragraph (d) of this section when the vent stream is diverted from the control device or recovery device, or has no flow rate, including the information specified in paragraphs (i)(2)(i) through (iii) of this section.

(i) For periods when the flow indicator is not operating, the identification of the flow indicator and report the start date, start time, and duration in hours.

(ii) For each flow event from a relief valve discharge subject to the requirements in § 60.612a(b)(1), the semiannual report must include the identification of the relief valve, the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of TOC in the gas in parts per million by volume and the resulting mass emissions of TOC in pounds that released to the atmosphere.

(iii) For each flow event from a bypass line subject to the requirements in § 60.612a(b)(2) and § 620a(e)(2), the semiannual report must include the identification of the bypass line, the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of TOC in the gas in parts per million by volume and the resulting mass emissions of TOC in pounds that bypass a control device or recovery device.

(3) All periods when a boiler or process heater was not operating (considering the records recorded under paragraph (e) of this section), including

the start date, start time, and duration in hours of each period.

(4) For each flare subject to the requirements in § 60.619a, the semiannual report must include an identification of the flare and the items specified in § 60.619a(l)(2).

(5) For each closed vent system subject to the requirements in § 60.620a, the semiannual report must include an identification of the closed vent system and the items specified in § 60.620a(i).

(6) Exceedances of the emission standard in table 1 to this subpart as indicated by a 3-hour average of the TOC CEMS and recorded under paragraph (c) of this section. For each exceedance, the report must include a list of the affected facilities or equipment, the start date and time of the exceedance, the duration (in hours) of the exceedance, an estimate of the quantity in pounds of each regulated pollutant emitted over the emission limit, a description of the method used to estimate the emissions, the cause of the exceedance (including unknown cause, if applicable), as applicable, and the corrective action taken.

(7) Periods when the TOC CEMS was inoperative. For each period, the report must include a list of the affected facilities or equipment, the start date and time of the period, the duration (in hours) of the period, the cause of the inoperability (including unknown cause, if applicable), as applicable, and the corrective action taken.

(8) Any change in equipment or process operation that increases the operating vent stream flow rate above the low flow exemption level in § 60.610a(c)(1), including a measurement of the new vent stream flow rate, as recorded under paragraph (h) of this section. These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed with the same time period to verify the recalculated flow value. The performance test is subject to the requirements of § 60.8 of the General Provisions and must be submitted according to paragraph (b)(1) of this section. Unless the facility qualifies for an exemption under § 60.610a(c), the facility must begin compliance with the requirements set forth in § 60.612a.

(j) If you are required to submit notifications or reports following the procedure specified in this paragraph (j), you must submit notifications or reports to the EPA via the 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 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 or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (j)(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 (j).

(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. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the SOCMI NSPS 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, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the SOCMI NSPS Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(k) If you are required to electronically submit notifications or reports through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with the electronic submittal requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (k)(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.

(l) If you are required to electronically submit notifications or reports through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with the electronic submittal requirement. To assert a claim of *force majeure,* you must meet the requirements outlined in paragraphs (l)(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.

(m) The requirements of paragraph (i) of this section remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with paragraph (i) of this section, provided that they comply with the requirements established by the State. The EPA will not approve a waiver of electronic reporting to the EPA in delegating enforcement authority. Thus, electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph cannot be used to relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

(n) If you seek to demonstrate compliance with § 60.610(c)(1), then you must submit to the Administrator, following the procedures in paragraph (b)(1) of this section, an initial report including a flow rate measurement using the test methods specified in § 60.614a.

(o) The Administrator will specify appropriate reporting and recordkeeping requirements where the owner or operator of an affected facility seeks to demonstrate compliance with the standards specified under § 60.612a other than as provided under § 60.613a.

(p) 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.

§ 60.616a What do the terms associated with reconstruction mean for this subpart?

For purposes of this subpart ''fixed capital cost of the new components,'' as used in § 60.15, includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following April 25, 2023. For purposes of this section, ''commenced'' means that you have undertaken a continuous program of component replacement or that you have entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

§ 60.617a What are the chemicals that I must produce to be affected by subpart IIIa?

Chemical name	CAS No.*
Acetaldehyde	75–07–0
Acetic acid	64–19–7
Acetone	67–64–1
Acetonitrile	75–05–8
Acetophenone	98–86–2
Acrolein	107–02–8
Acrylic acid	79–10–7
Acrylonitrile	107–13–1
Anthraquinone	84–65–1
Benzaldehyde	100–52–7
Benzoic acid, tech	65–85–0
1,3-Butadiene	106–99–0
p-t-Butyl benzoic acid	98–73–7
N-Butyric acid	107–92–6
Crotonic acid	3724–65–0
Cumene hydroperoxide	80–15–9
Cyclohexanol	108–93–0
Cyclohexanone	108–94–1
Dimethyl terephthalate	120–61–6
Ethylene dichloride	107–06–2
Ethylene oxide	75–21–8
Formaldehyde	50–00–0
Formic acid	64–18–6
Glyoxal	107–22–2
Hydrogen cyanide	74–90–8
Isobutyric acid	79–31–2
Isophthalic acid	121–91–5
Maleic anhydride	108–31–6
Methyl ethyl ketone	78–93–3
a-Methyl styrene	98–83–9
Phenol	108–95–2
Phthalic anhydride	85–44–9
Propionic acid	79–09–4
Propylene oxide	75–56–9
Styrene	100–42–5
Terephthalic acid	100–21–0

* CAS numbers refer to the Chemical Abstracts Registry numbers assigned to specific chemicals, isomers, or mixtures of chemicals. Some isomers or mixtures that are covered by the standards do not have CAS numbers assigned to them. The standards apply to all of the chemicals listed, whether CAS numbers have been assigned or not.

§ 60.618a [Reserved]

§ 60.619a What are my requirements if I use a flare to comply with this subpart?

(a) If you use a flare to comply with the TOC emission standard specified in Table 1 to this subpart, then you must meet the applicable requirements for flares as specified in §§ 63.670 and 63.671 of this chapter, including the provisions in tables 12 and 13 to part 63, subpart CC, of this chapter, 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 an affected facility, as determined on an annual average basis. For purposes of compliance with this paragraph (a), the following terms are defined in § 63.641 of this chapter: 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.

(b) When determining compliance with the pilot flame requirements specified in § 63.670(b) and (g) of this chapter, 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) of this chapter, the requirement effectively applies starting with the 15-minute block that includes a full 15 minutes of the flaring event. You are required to demonstrate compliance with the velocity and NHVcz requirements starting with the block that contains the fifteenth minute of a flaring event. You are 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) of this chapter, you must develop and implement the flare management plan no later than startup for a new flare that commenced construction on or after April 25, 2023.

(e) Instead of complying with § 63.670(o)(2)(iii) of this chapter, 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) following the procedures specified in § 60.615a(j).

(f) Section 63.670(o)(3)(ii) of this chapter and all references to it do not apply. Instead, you must comply with the maximum flare tip velocity operating limit at all times.

(g) Substitute ''affected facility'' 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 you must meet the following conditions:

(1) You are not required to comply with the flare tip velocity requirements in of § 63.670(d) and (k) of this chapter;

(2) The NHVcz for pressure-assisted mulit-point flares is 800 Btu/scf;

(3) You must determine the 15-minute block average NHVvg using only the direct calculation method specified in in § 63.670 (l)(5)(ii) of this chapter;

(4) Instead of complying with § 63.670(b) and (g) of this chapter, 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 you 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 deviation of the standard. Deviations in different 15-minute blocks from the same event are considered separate deviations. 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 you choose to conduct a cross-light performance demonstration as specified in this paragraph (i)(5), you 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 you conduct 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) You 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 part 63, subpart CC of this chapter.

(7) If a pressure-assisted multi-point flare is operating under the requirements of an approved alternative means of emission limitations, you 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 you choose to determine compositional analysis for net heating value with a continuous process mass spectrometer, then you must comply with the requirements specified in paragraphs (j)(1) through (7) of this section.

(1) You must meet the requirements in § 63.671(e)(2) of this chapter. You 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, 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 NHVvg.

(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 Performance Specification 9 of appendix B of this part, 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 part 63, subpart CC of this chapter, for the process mass spectrometer. You may use the alternative sampling line temperature allowed under Net Heating Value by Gas Chromatograph in table 13 to part 63, subpart CC.

(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 (j)(7).

Equation 1 to Paragraph (j)(7)

$$CE = \frac{C_m - C_a}{C_a} x\, 100 \text{ (Eq. 1)}$$

Where:

Cm = Average instrument response (ppm)
Ca = Certified cylinder gas value (ppm)

(k) If you use a gas chromatograph or mass spectrometer for compositional analysis for net heating value, then you 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 must be calculated using equation 2 to this paragraph (k).

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) of this chapter, you must comply with the reporting requirements specified in paragraphs (l)(1) and (2) of this section.

(1) The notification requirements specified in § 60.615a(a).

(2) The semiannual report specified in § 60.615a(i)(4) 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.

(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) of part 63, subpart CC of this chapter as applicable.

(iv) For flaring events meeting the criteria in § 63.670(o)(3) of this chapter 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) of this chapter 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) of this chapter, you 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) of this chapter 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. You 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 of appendix A–7 of this part, then the record must identify whether the visible emissions observation was performed, the results of each observation, total duration of observed visible emissions, and whether it was a 5-minute or 2-hour observation. 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) of this chapter, 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) of this chapter, 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) of this chapter. 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) of this chapter, as applicable.

(6) All periods during which operating values are outside of the applicable operating limits specified in § 63.670(d) through (f) of this chapter and paragraph (i) of this section when regulated material is being routed to the flare.

(7) All periods during which you do not perform flare monitoring according to the procedures in § 63.670(g) through (j) of this chapter.

(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) of this chapter 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) of this chapter.

(14) For any corrective action analysis for which implementation of corrective actions are required in § 63.670(o)(5) of this chapter, 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) You may elect to comply with the alternative means of emissions limitation requirements specified in paragraph (r) of § 63.670 of this chapter in lieu of the requirements in § 63.670(d) through (f) of this chapter, as applicable. However, instead of complying with § 63.670(r)(3)(iii) of this chapter, you 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: SOCMI NSPS 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 this chapter.

(2) The last sentence of § 63.670(o)(6) of this chapter.

(3) The phrase ''that were not caused by a *force majeure* event'' in § 63.670(o)(7)(ii) of this chapter.

(4) The phrase ''that were not caused by a *force majeure* event'' in § 63.670(o)(7)(iv) of this chapter.

§ 60.620a What are my requirements for closed vent systems?

(a) Except as provided in paragraphs (f) and (g) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) through (3) of this section.

(1) Conduct an initial inspection according to the procedures in paragraph (b) of this section unless the closed vent system is operated and maintained under negative pressure,

(2) Conduct annual inspections according to the procedures in paragraph (b) of this section unless the closed vent system is operated and maintained under negative pressure, and

(3) Conduct annual inspections for visible, audible, or olfactory indications of leaks.

(b) You must inspect each closed vent system according to the procedures specified in paragraphs (b)(1) through (6) of this section.

(1) Inspections must be conducted in accordance with Method 21 of appendix A of this part.

(2)(i) Except as provided in paragraph (b)(2)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 of appendix A of this part, except the instrument response factor criteria in section 3.1.2(a) of Method 21 must be for the average composition of the process fluid not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts which are not organic hazardous air pollutants or volatile organic compounds, the average stream response factor must be calculated on an inert-free basis.

(ii) If no instrument is available at the plant site that will meet the performance criteria specified in paragraph (b)(2)(i) of this section, the instrument readings may be adjusted by multiplying by the average response factor of the process fluid, calculated on an inert-free basis as described in paragraph (b)(2)(i) of this section.

(3) The detection instrument must be calibrated before use on each day of its use by the procedures specified in Method 21 of appendix A of this part.

(4) Calibration gases must be as follows:

(i) Zero air (less than 10 parts per million hydrocarbon in air); and

(ii) Mixtures of methane in air at a concentration less than 2,000 parts per million. A calibration gas other than methane in air may be used if the instrument does not respond to methane or if the instrument does not meet the performance criteria specified in paragraph (b)(2)(i) of this section. In such cases, the calibration gas may be a mixture of one or more of the compounds to be measured in air.

(5) You may elect to adjust or not adjust instrument readings for background. If you elect to not adjust readings for background, all such instrument readings must be compared directly to the applicable leak definition to determine whether there is a leak.

(6) If you elect to adjust instrument readings for background, you must determine the background concentration using Method 21 of appendix A of this part. After monitoring each potential leak interface, subtract the background reading from the maximum concentration indicated by the instrument. The arithmetic difference between the maximum concentration indicated by the instrument and the background level must be compared with 500 parts per million for determining compliance.

(c) Leaks, as indicated by an instrument reading greater than 500 parts per million above background or by visual, audio, or olfactory inspections, must be repaired as soon as practicable, except as provided in paragraph (d) of this section.

(1) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(2) Repair must be completed no later than 15 calendar days after the leak is detected.

(d) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a shutdown, as defined in § 60.2, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment must be complete by the end of the next shutdown.

(e) For each closed vent system that contains bypass lines that could divert a vent stream away from the control device and to the atmosphere, you must comply with the provisions of either paragraph (e)(1) or (2), except as specified in paragraph (e)(3) of this section.

(1) Install, calibrate, maintain, and operate a flow indicator that determines whether vent stream flow is present at least once every 15 minutes. You must keep hourly records of whether the flow indicator 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 vent stream is diverted to the atmosphere or the flow indicator is not operating. The flow indicator must be installed at the entrance to any bypass line; or

(2) Secure the bypass line valve in the closed position with a car-seal or a lock-and-key type configuration. A visual inspection of the seal or closure mechanism must be performed at least once every month to ensure the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(3) 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 (e).

(f) Any parts of the closed vent system that are designated, as described in paragraph (h)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (a)(1) and (2) of this section if:

(1) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1) and (2) of this section; and

(2) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(g) Any parts of the closed vent system are designated, as described in paragraph (h)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (a)(1) and (2) of this section if:

(1) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) You have a written plan that requires inspection of the equipment at least once every 5 years.

(h) You must record the information specified in paragraphs (h)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each closed vent system that contains bypass lines that could divert a vent stream away from the control device and to the atmosphere, you must keep a record of the information specified in either paragraph (h)(3)(i) or (ii) of this section in addition to the information specified in paragraph (h)(3)(iii) of this section.

(i) Hourly records of whether the flow indicator specified under paragraph (e)(1) of this section 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.

(ii) Where a seal mechanism is used to comply with paragraph (e)(2) of this section, hourly records of flow are not required. In such cases, you must record whether the monthly visual inspection of the seals or closure mechanisms has been done, and you must 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 configuration has been checked out, and records of any car-seal that has broken.

(iii) For each flow event from a bypass line subject to the requirements in paragraph (e) of this section, you 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, you must include an estimate of the volume of gas, the concentration of VOC in the gas and the resulting emissions of VOC that bypassed the control device using process knowledge and engineering estimates.

(4) For each inspection during which a leak is detected, a record of the information specified in paragraphs (h)(4)(i) through (viii) of this section.

(i) The instrument identification numbers; operator name or initials; and identification of the equipment.

(ii) The date the leak was detected and the date of the first attempt to repair the leak.

(iii) Maximum instrument reading measured by the method specified in paragraph (c) of this section after the leak is successfully repaired or determined to be nonrepairable.

(iv) ''Repair delayed'' and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(v) The name, initials, or other form of identification of the owner or operator (or designee) whose decision it was that repair could not be effected without a shutdown.

(vi) The expected date of successful repair of the leak if a leak is not repaired within 15 calendar days.

(vii) Dates of shutdowns that occur while the equipment is unrepaired.

(viii) The date of successful repair of the leak.

(5) For each inspection conducted in accordance with paragraph (b) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(6) For each inspection conducted in accordance with paragraph (a)(3) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(i) The semiannual report specified in § 60.615a(i)(5) must include the items specified in paragraphs (i)(1) through (3) of this section.

(1) Reports of the times of all periods recorded under paragraph (h)(3)(i) of this section when the vent stream is diverted from the control device through a bypass line. Include the start date, start time, and duration in hours of each period.

(2) Reports of all periods recorded under paragraph (h)(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 of each period.

(3) For bypass lines subject to the requirements in paragraph (e) of this section, the semiannual reports must include the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of VOC in the gas in parts per million by volume and the resulting mass emissions of VOC 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.

TABLE 1 TO SUBPART IIIa OF PART 60—EMISSION LIMITS AND STANDARDS FOR VENT STREAMS

For each. . .	You must. . .
1. Vent stream	a. Reduce emissions of TOC (minus methane and ethane) by 98 weight-percent, or to a TOC (minus methane and ethane) concentration of 20 ppmv on a dry basis corrected to 3 percent oxygen by venting emissions through a closed vent system to any combination of non-flare control devices and/or recovery system and meet the requirements specified in § 60.613a and § 60.620a; *or*
	b. Reduce emissions of TOC (minus methane and ethane) by venting emissions through a closed vent system to a flare and meet the requirements specified in § 60.619a and § 60.620a.

TABLE 2 TO SUBPART IIIa OF PART 60—MONITORING REQUIREMENTS FOR COMPLYING WITH 98 WEIGHT-PERCENT REDUCTION OF TOTAL ORGANIC COMPOUNDS EMISSIONS OR A LIMIT OF 20 PARTS PER MILLION BY VOLUME

Non-flare control device or recovery device	Parameters to be monitored
1. All control and recovery devices	a. Presence of flow diverted to the atmosphere from the control and recovery device; *or*
	b. Monthly inspections of sealed valves.
2. Absorber	a. Exit temperature of the absorbing liquid; *and*
	b. Exit specific gravity.
3. 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.[a]
4. Catalytic incinerator	Temperature upstream and downstream of the catalyst bed.
5. Carbon adsorber, regenerative	a. Total regeneration stream mass or volumetric flow during carbon bed regeneration cycle(s); *and*
	b. Temperature of the carbon bed after regeneration [and within 15 minutes of completing any cooling cycle(s)].
6. Carbon adsorber, non-regenerative or regenerated offsite	Breakthrough.
7. Condenser	Exit (product side) temperature.
8. Scrubber for halogenated vent streams	a. pH of scrubber effluent; *and*
	b. Scrubber liquid and gas flow rates.
9. Thermal incinerator	Firebox temperature.[a]
10. Control devices other than an incinerator, boiler, process heater, or flare; or recovery devices other than an absorber, condenser, or carbon adsorber.	As specified by the Administrator.

[a] Monitor may be installed in the firebox or in the ductwork immediately downstream of the firebox before any substantial heat exchange is encountered.

TABLE 3 TO SUBPART IIIa OF PART 60—OPERATING PARAMETERS, OPERATING PARAMETER LIMITS AND DATA MONITORING, RECORDKEEPING AND COMPLIANCE FREQUENCIES

For the operating parameter applicable to you, as specified in Table 2. . .	You must establish the following operating parameter limit. . .	And you must monitor, record, and demonstrate continuous compliance using these minimum frequencies. . .		
		Data measurement	Data recording	Data averaging period for compliance
Absorbers				
1. Exit temperature of the absorbing liquid.	Maximum temperature	Continuous	Every 15 minutes	3-hour block average.
2. Exit specific gravity	Exit specific gravity range	Continuous	Every 15 minutes	3-hour block average.
Boilers or process heaters (with a design heat input capacity <44MW and vent stream is not introduced with or as the primary fuel)				
3. Firebox temperature	Minimum firebox temperature	Continuous	Every 15 minutes	3-hour block average.
Catalytic incinerators				
4. Temperature in gas stream immediately before the catalyst bed.	Minimum temperature	Continuous	Every 15 minutes	3-hour block average.
5. Temperature difference between the catalyst bed inlet and the catalyst bed outlet.	Minimum temperature difference.	Continuous	Every 15 minutes	3-hour block average.
Carbon adsorbers				
6. Total regeneration stream mass flow during carbon bed regeneration cycle(s).	Minimum mass flow during carbon bed regeneration cycle(s).	Continuously during regeneration	Every 15 minutes during regeneration cycle.	Total flow for each regeneration cycle.
7. Total regeneration stream volumetric flow during carbon bed regeneration cycle(s).	Minimum volumetric flow during carbon bed regeneration cycle(s).	Continuously during regeneration	Every 15 minutes during regeneration cycle.	Total flow for each regeneration cycle.
8. Temperature of the carbon bed after regeneration [and within 15 minutes of completing any cooling cycle(s)].	Maximum temperature of the carbon bed after regeneration.	Continuously during regeneration and for 15 minutes after completing any cooling cycle(s).	Every 15 minutes during regeneration cycle (including any cooling cycle).	Average of regeneration cycle.
9. Breakthrough	As defined in § 60.611a	As required by § 60.613a(a)(6)(iii)(B)	Each monitoring event	N/A
Condensers				
10. Exit (product side) temperature.	Maximum temperature	Continuous	Every 15 minutes	3-hour block average.
Scrubbers for halogenated vent streams				
11. pH of scrubber effluent	Minimum pH	Continuous	Every 15 minutes	3-hour block average.
12. Influent liquid flow	Minimum inlet liquid flow	Continuous	Every 15 minutes	3-hour block average.
13. Influent liquid flow rate and gas stream flow rate.	Minimum influent liquid-to-gas ratio.	Continuous	Every 15 minutes	3-hour block average.
Thermal incinerators				
14. Firebox temperature	Minimum firebox temperature	Continuous	Every 15 minutes	3-hour block average.
Control devices other than an incinerator, boiler, process heater, or flare; or recovery devices other than an absorber, condenser, or carbon adsorber				
15. As specified by the Administrator.	As specified by the Administrator.	As specified by the Administrator	As specified by the Administrator.	As specified by the Administrator.

TABLE 4 TO SUBPART IIIa OF PART 60—CALIBRATION AND QUALITY CONTROL REQUIREMENTS FOR CONTINUOUS PARAMETER MONITORING SYSTEM (CPMS)

If you monitor this parameter. . .	Your accuracy requirements are. . .	And your calibration requirements are. . .
1. Temperature	a. ±1 percent over the normal range of temperature measured or 2.8 degrees Celsius (5 degrees Fahrenheit), whichever is greater, for non-cryogenic temperature ranges. b. ±2.5 percent over the normal range of temperature measured or 2.8 degrees Celsius (5 degrees Fahrenheit), whichever is greater, for cryogenic temperature ranges.	c. Performance evaluation annually and following any period of more than 24 hours throughout which the temperature exceeded the maximum rated temperature of the sensor, or the data recorder was off scale. d. Visual inspections and checks of CPMS operation every 3 months, unless the CPMS has a redundant temperature sensor. e. Selection of a representative measurement location.
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.
3. 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.

■ 26. Revise the heading of subpart NNN to read as follows:

Subpart NNN—Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations After December 30, 1983, and on or Before April 25, 2023

■ 27. Amend § 60.660 by revising paragraphs (b) introductory text and (c)(6) and adding paragraph (e) to read as follows:

§ 60.660 Applicability and designation of affected facility.

* * * * *

(b) The affected facility is any of the following for which construction, modification, or reconstruction commenced after December 30, 1983, and on or before April 25, 2023:

* * * * *

(c) * * *

(6) Each affected facility operated with a vent stream flow rate less than 0.008 scm/min is exempt from all provisions of this subpart except for the test method and procedure and the recordkeeping and reporting requirements in §§ 60.664(h) and 60.665(i), (l)(5), and (o).

* * * * *

(e) 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 this part or 40 CFR part 61 or 63, may elect to comply with the requirements in § 60.669a in lieu of all flare related requirements in any other regulation in this part or 40 CFR part 61 or 63.

■ 28. Amend § 60.661 by revising the definition of ''Flame zone'' to read as follows:

§ 60.661 Definitions.

* * * * *

Flame zone means the portion of the combustion chamber in a boiler or process heater occupied by the flame envelope.

* * * * *

■ 29. Amend § 60.664 by revising paragraphs (b)(4) introductory text and (e) to read as follows:

§ 60.664 Test methods and procedures.

* * * * *

(b) * * *

(4) Method 18 of appendix A–6 to this part to determine the concentration of TOC in the control device outlet and the concentration of TOC in the inlet when the reduction efficiency of the control device is to be determined. ASTM D6420–18 (incorporated by reference, see § 60.17) 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 may not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method.

* * * * *

(e) The following test methods, except as provided under § 60.8(b), shall be used for determining the net heating value of the gas combusted to determine compliance under § 60.662(b) and for determining the process vent stream TRE index value to determine compliance under § 60.662(c).

(1)(i) Method 1 or 1A of appendix A–1 to this part, as appropriate, for selection of the sampling site. The sampling site for the vent stream flow rate and molar composition determination prescribed in paragraphs (e)(2) and (3) of this section shall be, except for the situations outlined in paragraph (e)(1)(ii) of this section, prior to the inlet of any control device, prior to any post-distillation dilution of the stream with air, and prior to any post-distillation introduction of halogenated compounds into the process vent stream. No transverse site selection method is needed for vents smaller than 10 centimeters (4 inches) in diameter.

(ii) If any gas stream other than the distillation vent stream from the affected facility is normally conducted through the final recovery device.

(A) The sampling site for vent stream flow rate and molar composition shall be prior to the final recovery device and prior to the point at which the nondistillation stream is introduced.

(B) The efficiency of the final recovery device is determined by measuring the TOC concentration using Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in paragraph (b)(4) of this section, at the inlet to the final recovery device after the introduction of any nondistillation vent stream and at the outlet of the final recovery device.

(C) This efficiency is applied to the TOC concentration measured prior to the final recovery device and prior to the introduction of the nondistillation stream to determine the concentration of TOC in the distillation vent stream from the final recovery device. This concentration of TOC is then used to perform the calculations outlined in § 60.664(e)(4) and (5).

(2) The molar composition of the process vent stream shall be determined as follows:

(i) Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in paragraph (b)(4) of this section, to measure the concentration of TOC including those containing halogens.

(ii) ASTM D1946–77 or 90 (Reapproved 1994) (incorporation by reference as specified in § 60.17 of this part) to measure the concentration of carbon monoxide and hydrogen.

(iii) Method 4 of appendix A–3 to this part to measure the content of water vapor.

(3) The volumetric flow rate shall be determined using Method 2, 2A, 2C, or 2D of appendix A–1 to this part, as appropriate.

(4)(i) The net heating value of the vent stream shall be calculated using the following equation:

$$H_T = K_1\left(\sum_{j=1}^{n} C_j H_j\right)$$

Where:

H_T = Net heating value of the sample, MJ/scm (Btu/scf), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg (77 °F and 30 in. Hg), but the standard temperature for determining the volume corresponding to one mole is 20 °C (68 °F).

K_1 = 1.74×10^{-7} (1/ppm) (g-mole/scm) (MJ/kcal) (metric units), where standard temperature for (g-mole/scm) is 20 °C.

= 1.03×10^{-11} (1/ppm) (lb-mole/scf) (Btu/kcal) (English units) where standard temperature for (lb/mole/scf) is 68 °F.

C_j = Concentration on a wet basis of compound j in ppm, as measured for organics by Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in paragraph (b)(4) of this section, and measured for hydrogen and carbon monoxide by ASTM D1946–77 or 90 (Reapproved 1994) (incorporated by reference, see § 60.17) as indicated in paragraph (e)(2) of this section.

H_j = Net heat of combustion of compound j, kcal/(g-mole) [kcal/(lb-mole)], based on combustion at 25 °C and 760 mm Hg (77 °F and 30 in. Hg).

(ii) The heats of combustion of vent stream components would be required to be determined using ASTM D2382–76 (incorporated by reference as specified in § 60.17) if published values are not available or cannot be calculated.

(5) The emission rate of TOC in the vent stream shall be calculated using the following equation:

$$E_{TOC} = K_2\left[\sum_{j=1}^{n} C_j M_j\right] Q_s$$

Where:

E_{TOC} = Measured emission rate of TOC, kg/hr (lb/hr).

K_2 = 2.494×10^{-6} (1/ppm) (g-mole/scm) (kg/g) (min/hr) (metric units), where standard temperature for (g-mole/scm) is 20 °C.

= 1.557×10^{-7} (1/ppm) (lb-mole/scf) (min/hr) (English units), where standard temperature for (lb-mole/scf) is 68 °F.

C_j = Concentration on a wet basis of compound j in ppm, as measured by Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in paragraph (b)(4) of this section, as indicated in paragraph (e)(2) of this section.

M_j = Molecular weight of sample j, g/g-mole (lb/lb-mole).

Q_s = Vent stream flow rate, scm/min (scf/min), at a temperature of 20 °C (68 °F).

(6) The total process vent stream concentration (by volume) of compounds containing halogens (ppmv, by compound) shall be summed from the individual concentrations of compounds containing halogens which were measured by Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in paragraph (b)(4) of this section.

* * * * *

■ 30. Amend § 60.665 by revising paragraphs (b) introductory text, (l) introductory text, (l)(5) and (6), and (m) and adding paragraphs (q), (r), and (s) as follows:

§ 60.665 Reporting and recordkeeping requirements.

* * * * *

(b) Each owner or operator subject to the provisions of this subpart shall keep an up-to-date, readily accessible record of the following data measured during each performance test, and also include the following data in the report of the initial performance test required under § 60.8. Where a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to comply with § 60.662(a), a report containing performance test data need not be submitted, but a report containing the information in § 60.665(b)(2)(i) is required. The same data specified in this section shall be submitted in the reports of all subsequently required performance tests where either the emission control efficiency of a control device, outlet concentration of TOC, or the TRE index value of a vent stream from a recovery system is determined. Beginning on July 15, 2024, owners and operators must submit the performance test report following the procedures specified in paragraph (q) of this section. Data collected using test methods that are 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, the owner or operator 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 an alternate electronic file.

* * * * *

(l) Each owner or operator that seeks to comply with the requirements of this subpart by complying with the requirements of § 60.660 (c)(4), (c)(5), or (c)(6) or § 60.662 shall submit to the Administrator semiannual reports of the following recorded information. The initial report shall be submitted within 6 months after the initial start-up date. On and after July 15, 2025 or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for 1 year, whichever date is later, owners and operators must submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (q) of this section. 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.

* * * * *

(5) Any change in equipment or process operation that increases the operating vent stream flow rate above the low flow exemption level in § 60.660(c)(6), including a measurement of the new vent stream flow rate, as recorded under § 60.665(i). These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed with the same time period to verify the recalculated flow value and to obtain the vent stream characteristics of heating value and E_{TOC}. The performance test is subject to the requirements of § 60.8, and the performance test must be reported according to paragraph (b) of this section. Unless the facility qualifies for an exemption under the low capacity exemption status in § 60.660(c)(5), the facility must begin compliance with the requirements set forth in § 60.662.

(6) Any change in equipment or process operation, as recorded under paragraph (j) of this section, that increases the design production capacity above the low capacity exemption level in § 60.660(c)(5) and the new capacity resulting from the change for the distillation process unit containing the affected facility. These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed within the same time period to obtain the vent stream flow rate, heating value, and E_{TOC}. The performance test is subject to the requirements of § 60.8, and the performance test must be reported according to paragraph (b) of this section. The facility must begin compliance with the requirements set forth in § 60.660(d) or § 60.662. If the facility chooses to comply with § 60.662, the facility may qualify for an exemption in § 60.660(c)(4) or (6).

* * * * *

(m) The requirements of § 60.665(l) remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with § 60.665(l), provided that they comply with the requirements established by the State. The EPA will not approve a waiver of electronic reporting to the EPA in delegating enforcement authority. Thus, electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph cannot be used to relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

* * * * *

(q) If an owner or operator is required to submit notifications or reports following the procedure specified in this paragraph (q), the owner or operator must submit notifications or 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 the owner or operator. Do not use CEDRI to submit information the owner or operator claims as CBI. Although the EPA does not expect persons to assert a claim of CBI, if an owner or operator wishes to assert a CBI claim for some of the information in the report or notification, the owner or operator must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (q)(1) and (2) of this section. Clearly mark the part or all of the information that claimed 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. The owner or operator 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 (q).

(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. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the SOCMI NSPS Sector Lead. Owners and operators who do not have their own file sharing service and who require assistance with submitting large electronic files that exceed the file size limit for email attachments should email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If an owner or operator cannot transmit the file electronically, the owner or operator may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park,

North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the SOCMI NSPS Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(r) Owners and operators required to electronically submit notifications or reports through CEDRI in the EPA's CDX may assert a claim of EPA system outage for failure to timely comply with the electronic submittal requirement. To assert a claim of EPA system outage, owners and operators must meet the requirements outlined in paragraphs (r)(1) through (7) of this section.

(1) The owner or operator 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) The owner or operator must submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) The owner or operator 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 the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the report was submitted.

(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.

(s) Owners and operators required to electronically submit notifications or reports through CEDRI in the EPA's CDX may assert a claim of *force majeure* for failure to timely comply with the electronic submittal requirement. To assert a claim of *force majeure,* owners and operators must meet the requirements outlined in paragraphs (s)(1) through (5) of this section.

(1) An owner or operator 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 the owner or operator 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) The owner or operator must submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) An owner or operator 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 the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the report was submitted.

(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.

■ 31. Amend § 60.668 by revising paragraph (b) to read as follows:

§ 60.668 Delegation of authority.

* * * * *

(b) Authorities which will not be delegated to States: § 60.663(e) and approval of an alternative to any electronic reporting to the EPA required by this subpart.

■ 32. Add subpart NNNa to read as follows:

Subpart NNNa—Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations for Which Construction, Reconstruction, or Modification Commenced After April 25, 2023

Subpart NNNa—Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations for Which Construction, Reconstruction, or Modification Commenced After April 25, 2023

§ 60.660a Am I subject to this subpart?

(a) You are subject to this subpart if you operate an affected facility designated in paragraph (b) of this section that produces any of the chemicals listed in § 60.667a as a product, co-product, by-product, or intermediate, except as provided in paragraph (c) of this section.

(b) The affected facility is any of the following for which construction, modification, or reconstruction commenced after April 25, 2023:

(1) Each distillation unit not discharging its vent stream into a recovery system.

(2) Each combination of a distillation unit and the recovery system into which its vent stream is discharged.

(3) Each combination of two or more distillation units and the common recovery system into which their vent streams are discharged.

(c) Exemptions from the provisions of paragraph (a) of this section are as follows:

(1) Any distillation unit operating as part of a process unit which produces coal tar or beverage alcohols, or which uses, contains, and produces no VOC is not an affected facility.

(2) Any distillation unit that is subject to the provisions of subpart DDD is not an affected facility.

(3) Any distillation unit that is designed and operated as a batch operation is not an affected facility.

(4) Each affected facility in a process unit with a total design capacity for all chemicals produced within that unit of less than one gigagram per year is exempt from all provisions of this subpart except for the recordkeeping and reporting requirements in § 60.665a(h), (j)(6), and (o).

(5) Each affected facility operated with a vent stream flow rate less than 0.008 standard cubic meter per minute (scm/min) is exempt from all provisions of this subpart except for the test method and procedure and the recordkeeping and reporting requirements in § 60.664a(e) and § 60.665a(i), (j)(7), and (p).

(6) Each affected facility operated with a vent stream flow rate less than 0.001 pound per hour (lb/hr) of TOC is exempt from all provisions of this subpart except for the test method and procedure and the recordkeeping and reporting requirements in §§ 60.664a(f) and 60.665a(i), (j)(7), and (p).

(7) A vent stream going to a fuel gas system as defined in § 63.661a.

§ 60.661a What definitions must I know?

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

Batch distillation operation means a noncontinuous distillation operation in which a discrete quantity or batch of liquid feed is charged into a distillation unit and distilled at one time. After the initial charging of the liquid feed, no additional liquid is added during the distillation operation.

Breakthrough means the time when the level of 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.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam.

By compound means by individual stream components, not carbon equivalents.

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.

Continuous recorder means a data recording device recording an instantaneous data value at least once every 15 minutes.

Distillation operation means an operation separating one or more feed stream(s) into two or more exit stream(s), each exit stream having component concentrations different from those in the feed stream(s). The separation is achieved by the redistribution of the components between the liquid and vapor-phase as they approach equilibrium within the distillation unit.

Distillation unit means a device or vessel in which distillation operations occur, including all associated internals (such as trays or packing) and accessories (such as reboiler, condenser, vacuum pump, steam jet, etc.), plus any associated recovery system.

Flame zone means the portion of the combustion chamber in a boiler or process heater occupied by the flame envelope.

Flow indicator means a device which indicates whether gas flow is present in a vent stream.

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.

Halogenated vent stream means any vent stream determined to have a total concentration (by volume) of compounds containing halogens of 20 ppmv (by compound) or greater.

Incinerator means any enclosed combustion device that is used for destroying organic compounds and does not extract energy in the form of steam or process heat.

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.

Primary fuel means the fuel fired through a burner or a number of similar burners. The primary fuel provides the principal heat input to the device, and the amount of fuel is sufficient to sustain operation without the addition of other fuels.

Process heater means a device that transfers heat liberated by burning fuel to fluids contained in tubes, including all fluids except water that is heated to produce steam.

Process unit means equipment assembled and connected by pipes or ducts to produce, as intermediates or final products, one or more of the chemicals in § 60.667a. A process unit can operate independently if supplied with sufficient fuel or raw materials and sufficient product storage facilities.

Product means any compound or chemical listed in § 60.667a that is produced for sale as a final product as that chemical, or for use in the production of other chemicals or compounds. By-products, co-products, and intermediates are considered to be products.

Recovery device means an individual unit of equipment, such as an absorber, carbon adsorber, or condenser, capable of and used for the purpose of recovering chemicals for use, reuse, or sale.

Recovery system means an individual recovery device or series of such devices applied to the same vent stream.

Relief valve means a valve used only to release an unplanned, nonroutine discharge. A relief valve discharge results from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause that requires immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage.

Total organic compounds (TOC) means those compounds measured according to the procedures in Method 18 of appendix A–6 of this part or the concentration of organic compounds measured according to the procedures in Method 21 or Method 25A of appendix A–7 of this part.

Vent stream means any gas stream discharged directly from a distillation facility to the atmosphere or indirectly to the atmosphere after diversion through other process equipment. The vent stream excludes equipment leaks including, but not limited to, pumps, compressors, and valves.

§ 60.662a What standards and associated requirements must I meet?

(a) You must comply with the emission limits and standards specified in table 1 to this subpart and the requirements specified in paragraphs (b) and (c) of this section for each vent stream on and after the date on which the initial performance test required by §§ 60.8 and 60.664a is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after the initial start-up, whichever date comes first. The standards in this section apply at all times, including periods of startup, shutdown and malfunction. As provided in § 60.11(f), this provision supersedes the exemptions for periods of startup, shutdown and malfunction in the general provisions in subpart A of this part.

(b) The following release events from an affected facility are a violation of the emission limits and standards specified in table 1 to this subpart.

(1) Any relief valve discharge to the atmosphere of a vent stream.

(2) The use of a bypass line at any time on a closed vent system to divert emissions to the atmosphere, or to a control device or recovery device not meeting the requirements specified in § 60.663a.

(c) You may designate a vent stream 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. You must comply with the applicable requirements in paragraphs (c)(1) through (3) of this section for each maintenance vent. Any vent stream designated as a maintenance vent is only subject to the maintenance vent provisions in this paragraph (c) and the associated recordkeeping and reporting requirements in § 60.665a(g), respectively.

(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 § 60.669a, as applicable, or using any combination of a non-flare control device or recovery device meeting the requirements in table 1 to this subpart until one of the following conditions, as applicable, is met.

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

(ii) If there is no ability to measure the LEL of the vapor in the equipment based on the design of the equipment, the pressure in the equipment served by the maintenance vent is reduced to 5 pounds per square inch gauge (psig) or less. Upon opening the maintenance vent, active purging of the equipment cannot be used until the LEL of the vapors in the maintenance vent (or inside the equipment if the maintenance vent is a hatch or similar type of opening) is less than 10 percent.

(iii) The equipment served by the maintenance vent contains less than 50 pounds of total VOC.

(iv) 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 (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 (c)(1)(iii) of this section, you must determine the LEL or, if applicable, equipment pressure using process instrumentation or portable measurement devices and follow procedures for calibration and maintenance according to manufacturer's specifications.

(3) For maintenance vents complying with the alternative in paragraph (c)(1)(iii) of this section, you 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.

§ 60.663a What are my monitoring, installation, operation, and maintenance requirements?

(a) Except as specified in paragraphs (a)(5) through (7) of this section, if you use a non-flare control device or recovery system to comply with the TOC emission limit specified in table 1 to this subpart, then you must comply with paragraphs (a)(1) through (4), (b), and (c) of this section.

(1) Install a continuous parameter monitoring system(s) (CPMS) and monitor the operating parameter(s) applicable to the control device or recovery system as specified in table 2 to this subpart or established according to paragraph (c) of this section.

(2) Establish the applicable minimum, maximum, or range for the operating parameter limit as specified in table 3 to this subpart or established according to paragraph (c) of this section by calculating the value(s) as the arithmetic average of operating parameter measurements recorded during the three test runs conducted for the most recent performance test. You may operate outside of the established operating parameter limit(s) during subsequent performance tests in order to establish new operating limits. You must include the updated operating limits with the performance test results submitted to the Administrator pursuant to § 60.665a(b). Upon establishment of a new operating limit, you must thereafter operate under the new operating limit. If the Administrator determines that you did not conduct the performance test in accordance with the applicable requirements or that the operating limit established during the performance test does not correspond to the conditions specified in § 60.664a(a), then you must conduct a new performance test and establish a new operating limit.

(3) Monitor, record, and demonstrate continuous compliance using the minimum frequencies specified in table 3 to this subpart or established according to paragraph (c) of this section.

(4) Comply with the calibration and quality control requirements as specified in table 4 to this subpart or established according to paragraph (c) of this section that are applicable to the CPMS used.

(5) Any vent stream introduced with primary fuel into a boiler or process heater is exempt from the requirements specified in paragraphs (a)(1) through (4) of this section.

(6) If you vent 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 install a system of two or more adsorber units in series and comply with the requirements specified in paragraphs (a)(6)(i) through (iii) of this section in addition to the requirements specified in paragraphs (a)(1) through (4) 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 TOC concentration through a sample port at the outlet of the first adsorber bed in series according to the schedule in paragraph (a)(6)(iii)(B) of this section. You must measure the concentration of TOC using either a portable analyzer, in accordance with Method 21 of appendix A–7 of this part using methane, propane, or isobutylene as the calibration gas or Method 25A of appendix A–7 of this part using methane or propane as the calibration gas.

(iii) Comply with paragraph (a)(6)(iii)(A) of this section and comply with the monitoring frequency according to paragraph (a)(6)(iii)(B) of this section.

(A) The first adsorber in series must be replaced immediately when breakthrough, as defined in § 60.661a, 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 (a)(6)(iii)(A), ''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. You 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)(6)(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.

(7) If you install a continuous emissions monitoring system (CEMS) to demonstrate compliance with the TOC standard in table 1 of this subpart, you must comply with the requirements specified in § 60.664a(g) in lieu of the requirements specified in paragraphs (a)(1) through (4) and (c) of this section.

(b) If you vent emissions through a closed vent system to a boiler or process heater, then the vent stream must be introduced into the flame zone of the boiler or process heater.

(c) If you seek to demonstrate compliance with the standards specified under § 60.662a with control devices other than an incinerator, boiler, process heater, or flare; or recovery devices other than an absorber, condenser, or carbon adsorber, you shall provide to the Administrator prior to conducting the initial performance test information describing the operation of the control device or recovery device and the parameter(s) which would indicate proper operation and maintenance of the device and how the parameter(s) are indicative of control of TOC emissions. The Administrator may request further information and will specify appropriate monitoring procedures or requirements, including operating parameters to be monitored, averaging times for determining compliance with the operating parameter limits, and ongoing calibration and quality control requirements.

§ 60.664a What test methods and procedures must I use to determine compliance with the standards?

(a) For the purpose of demonstrating compliance with the emission limits and standards specified in table 1 to this subpart, all affected facilities must be run at full operating conditions and flow rates during any performance test. Performance tests are not required if you determine compliance using a CEMS that meets the requirements outlined in paragraph (g) of this section.

(1) Conduct initial performance tests no later than the date required by § 60.8(a).

(2) Conduct subsequent performance tests no later than 60 calendar months after the previous performance test.

(b) The following methods, except as provided in § 60.8(b) must, must be used as reference methods to determine compliance with the emission limit or percent reduction efficiency specified in table 1 to this subpart for non-flare control devices and/or recovery systems.

(1) Method 1 or 1A of appendix A–1 to this part, as appropriate, for selection of the sampling sites. The inlet sampling site for determination of vent stream molar composition or TOC (less methane and ethane) reduction efficiency shall be prior to the inlet of the control device or, if equipped with a recovery system, then prior to the inlet of the first recovery device in the recovery system.

(2) Method 2, 2A, 2C, or 2D of appendix A–1 to this part, as appropriate, for determination of the gas volumetric flow rates.

(3) Method 3A of appendix A–2 to this part or the manual method in ANSI/ASME PTC 19.10–1981 (incorporated by reference, see § 60.17) must be used to determine the oxygen concentration (%O2d) for the purposes of determining compliance with the 20 ppmv limit. The sampling site must be the same as that of the TOC samples, and the samples must be taken during the same time that the TOC samples are taken. The TOC concentration corrected to 3 percent O_2 (C_c) must be computed using the following equation:

Equation 1 to Paragraph (b)(3)

$$C_c = C_{TOC}\frac{17.9}{20.9 - \%O_{2d}}$$

Where:

C_c = Concentration of TOC corrected to 3 percent O_2, dry basis, ppm by volume.

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

$\%O_{2d}$ = Concentration of O_2, dry basis, percent by volume.

(4) Method 18 of appendix A–6 to this part to determine the concentration of TOC in the control device outlet or in the outlet of the final recovery device in a recovery system, and to determine the concentration of TOC in the inlet when the reduction efficiency of the control device or recovery system is to be determined. ASTM D6420–18 (incorporated by reference, see § 60.17) 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 may not be used for methane and ethane; and ASTM D6420–18 must not be used as a total VOC method.

(i) The sampling time for each run must be 1 hour in which either an integrated sample or at least four grab samples must be taken. If grab sampling is used then the samples must be taken at 15-minute intervals.

(ii) The emission reduction (R) of TOC (minus methane and ethane) must be determined using the following equation:

Equation 2 to Paragraph (b)(4)(ii)

$$R = \frac{E_i - E_o}{E_i} \times 100$$

Where:

R = Emission reduction, percent by weight.

E_i = Mass rate of TOC entering the control device or recovery system, kg/hr (lb/hr).

E_o = Mass rate of TOC discharged to the atmosphere, kg/hr (lb/hr).

(iii) The mass rates of TOC (E_i, E_o) must be computed using the following equations:

Equations 3 and 4 to Paragraph (b)(4)(iii)

$$E_i = K_2 \left(\sum_{j=1}^{n} C_{ij} M_{ij} \right) Q_i$$

$$E_O = K_2 \left(\sum_{j=1}^{n} C_{oj} M_{oj} \right) Q_O$$

Where:

C_{ij}, C_{oj} = Concentration of sample component "j" of the gas stream at the inlet and outlet of the control device or recovery system, respectively, dry basis, ppm by volume.

M_{ij}, M_{oj} = Molecular weight of sample component "j" of the gas stream at the inlet and outlet of the control device or recovery system, respectively, g/g-mole (lb/lb-mole).

Q_i, Q_o = Flow rate of gas stream at the inlet and outlet of the control device or recovery system, respectively, dscm/min (dscf/min).

K_2 = 2.494×10^{-6} (1/ppm)(g-mole/scm) (kg/g) (min/hr) (metric units), where standard temperature for (g-mole/scm) is 20 °C.

= 1.557×10^{-7} (1/ppm) (lb-mole/scf) (min/hr) (English units), where standard temperature for (lb-mole/scf) is 68 °F.

(iv) The TOC concentration (C_{TOC}) is the sum of the individual components and must be computed for each run using the following equation:

Equation 5 to Paragraph (b)(4)(iv)

$$C_{TOC} = \sum_{j=1}^{n} C_j$$

Where:

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

C_j = Concentration of sample components "j", dry basis, ppm by volume.

n = Number of components in the sample.

(c) The requirement for initial and subsequent performance tests are waived, in accordance with § 60.8(b), for the following:

(1) When a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to seek to comply with the emission limit or percent reduction efficiency specified in table 1 to this subpart.

(2) When a vent stream is introduced into a boiler or process heater with the primary fuel.

(3) 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 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 40 CFR 63.1207(j) and complies with the requirements of 40 CFR part 63, subpart EEE; or

(iv) Complies with 40 CFR part 63, subpart EEE and will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date the owner or operator would have been required to submit the initial performance test report for this subpart.

(4) The Administrator reserves the option to require testing at such other times as may be required, as provided for in section 114 of the Act.

(d) For purposes of complying with the 98 weight-percent reduction in § 60.702a(a), if the vent stream entering a boiler or process heater with a design capacity less than 44 MW (150 million Btu/hour) is introduced with the combustion air or as secondary fuel, the weight-percent reduction of TOC (minus methane and ethane) across the combustion device shall be determined by comparing the TOC (minus methane and ethane) in all combusted vent streams, primary fuels, and secondary fuels with the TOC (minus methane and ethane) exiting the combustion device.

(e) Any owner or operator subject to the provisions of this subpart seeking to demonstrate compliance with § 60.660a(c)(5) must use Method 2, 2A, 2C, or 2D of appendix A–1 to this part as appropriate, for determination of volumetric flow rate. The owner or operator must conduct three velocity traverses and determine the volumetric flow rate for each traverse. If the pipe or duct is smaller than four inches in diameter, the owner operator may conduct the measurement at the centroid of the duct instead of conducting a traverse; the measurement period must be at least five minutes long and data must be recorded at least once every 30 seconds. Owners and operators who conduct the determination with

Method 2A or 2D must record volumetric flow rate every 30 seconds for at least five minutes.

(f) Any owner or operator subject to the provisions of this subpart seeking to demonstrate compliance with § 60.660a(c)(6) must use the following methods:

(1) Method 1 or 1A of appendix A–1 to this part, as appropriate.

(2) Method 2, 2A, 2C, or 2D of appendix A–1 to this part, as appropriate, for determination of the gas volumetric flow rates.

(3) Method 18 of appendix A–6 to this part to determine the concentration of TOC. ASTM D6420–18 (incorporated by reference, see § 60.17) 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 may not be used for methane and ethane; and ASTM D6420–18 must not be used as a total VOC method.

(i) The sampling site must be at a location that provides a representative sample of the vent stream.

(ii) Perform three test runs. The sampling time for each run must be 1 hour in which either an integrated sample or at least four grab samples must be taken. If grab sampling is used then the samples must be taken at 15-minute intervals.

(iii) The mass rate of TOC (E) must be computed using the following equation:

Equation 6 to Paragraph (f)(3)(iii)

$$E = K\left(\sum_{j=1}^{n} C_j M_j\right) Q$$

Where:

C_j = Concentration of sample component ''j'' of the gas stream at the representative sampling location, dry basis, ppm by volume.

M_j = Molecular weight of sample component ''j'' of the gas stream at the representative sampling location, g/g-mole (lb/lb-mole).

Q = Flow rate of gas stream at the representative sampling location, dscm/min (dscf/min).

K = 2.494×10^{-6} (1/ppm)(g-mole/scm) (kg/g) (min/hr) (metric units), where standard temperature for (g-mole/scm) is 20 °C.

= 1.557×10^{-7} (1/ppm) (lb-mole/scf) (min/hr) (English units), where standard temperature for (lb-mole/scf) is 68 °F.

(g) If you use a CEMS to demonstrate initial and continuous compliance with the TOC standard in table 1 of this subpart, each CEMS must be installed, operated and maintained according to the requirements in § 60.13 and paragraphs (g)(1) through (5) of this section.

(1) You must use a CEMS that is capable of measuring the target analyte(s) as demonstrated using either process knowledge of the control device inlet stream or the screening procedures of Method 18 of appendix A–6 to this part on the control device inlet stream. If your CEMS is located after a combustion device and inlet stream to that device includes methanol or formaldehyde, you must use a CEMS which meets the requirements in Performance Specification 9 or 15 of appendix B to this part.

(2) Each CEMS must be installed, operated, and maintained according to the applicable performance specification of appendix B to this part and the applicable quality assurance procedures of appendix F to this part. Locate the sampling probe or other interface at a measurement location such that you obtain representative measurements of emissions from the affected facility.

(3) Conduct a performance evaluation of each CEMS within 180 days of installation of the monitoring system. Conduct subsequent performance evaluations of the CEMS no later than 12 calendar months after the previous performance evaluation. The results each performance evaluation must be submitted in accordance with § 60.665a(b)(1).

(4) You must determine TOC concentration according to one of the following options. The span value of the TOC CEMS must be approximately 2 times the emission standard specified in table 1 of this subpart.

(i) For CEMS meeting the requirements of Performance Specification 15 of appendix B to this part, determine the target analyte(s) for calibration using either process knowledge of the control device inlet stream or the screening procedures of Method 18 of appendix A–6 to this part on the control device inlet stream. The individual analytes used to quantify TOC must represent 98 percent of the expected mass of TOC present in the stream. Report the results of TOC as equivalent to carbon (C1).

(ii) For CEMS meeting the requirements of Performance Specification 9 of appendix B of this part, determine the target analyte(s) for calibration using either process knowledge of the control device inlet stream or the screening procedures of Method 18 of appendix A–6 to this part on the control device inlet stream. The individual analytes used to quantify TOC must represent 98 percent of the expected mass of TOC present in the stream. Report the results of TOC as equivalent to carbon (C1).

(iii) For CEMS meeting the requirements of Performance Specification 8 of appendix B to this part used to monitor performance of a combustion device, calibrate the instrument on the predominant organic HAP and report the results as carbon (C1), and use Method 25A of appendix A–7 to this part as the reference method for the relative accuracy tests. You must also comply with procedure 1 of appendix F to this part.

(iv) For CEMS meeting the requirements of Performance Specification 8 of appendix B to this part used to monitor performance of a noncombustion device, determine the predominant organic compound using either process knowledge or the screening procedures of Method 18 on the control device inlet stream. Calibrate the monitor on the predominant organic compound and report the results as C_1. Use Method 25A of appendix A–7 to this part as the reference method for the relative accuracy tests. You must also comply with procedure 1 of appendix F to this part.

(5) You must determine stack oxygen concentration at the same location where you monitor TOC concentration with a CEMS that meets the requirements of Performance Specification 3 of appendix B to this part. The span value of the oxygen CEMS must be approximately 25 percent oxygen. Use Method 3A of appendix A–2 to this part as the reference method for the relative accuracy tests.

(6) You must maintain written procedures for your CEMS. At a minimum, the procedures must include the information in paragraph (g)(6)(i) through (vi) of this section:

(i) Description of CEMS installation location.

(ii) Description of the monitoring equipment, including the manufacturer and model number for all monitoring equipment components and the span of the analyzer.

(iii) Routine quality control and assurance procedures.

(iv) Conditions that would trigger a CEMS performance evaluation, which must include, at a minimum, a newly installed CEMS; a process change that is expected to affect the performance of the CEMS; and the Administrator's request for a performance evaluation under section 114 of the Clean Air Act.

(v) Ongoing operation and maintenance procedures.

(vi) Ongoing recordkeeping and reporting procedures.

§ 60.665a What records must I keep and what reports must I submit?

(a) You must notify the Administrator of the specific provisions of table 1 of this subpart or § 60.662a(c) with which you have elected to comply. Notification must be submitted with the notification of initial start-up required by § 60.7(a)(3). If you elect at a later date to use an alternative provision of table 1 to this subpart with which you will comply, then you must notify the Administrator 90 days before implementing a change and, upon implementing the change, you must conduct a performance test as specified by § 60.664a within 180 days.

(b) If you use a non-flare control device or recovery system to comply with the TOC emission limit specified in table 1 to this subpart, then you must keep an up-to-date, readily accessible record of the data measured during each performance test to show compliance with the TOC emission limit. You must also include all of the data you use to comply with § 60.663a(a)(2). The same data specified in this paragraph must also be submitted in the initial performance test required in § 60.8 and the reports of all subsequently required performance tests where either the emission reduction efficiency of a control device or recovery system or outlet concentration of TOC is determined. Alternatively, you must keep records of each CEMS performance evaluation.

(1) Within 60 days after the date of completing each performance test or CEMS performance evaluation required by this subpart, you must submit the results of the performance test or performance evaluation following the procedures specified in paragraph (k) of this section. Data collected using test methods and performance evaluations of CEMS measuring relative accuracy test audit (RATA) pollutants 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 or performance evaluation 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 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.

(2) If you use a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater to comply with the TOC emission limit specified in table 1 to this subpart, then you are not required to submit a report containing performance test data; however, you must submit a description of the location at which the vent stream is introduced into the boiler or process heater.

(c) If you use a non-flare control device or recovery system to comply with the TOC emission limit specified in Table 1 to this subpart, then you must keep up-to-date, readily accessible records of periods of operation during which the operating parameter limits established during the most recent performance test are exceeded or periods of operation where the TOC CEMS, averaged on a 3-hour block basis, indicate an exceedance of the emission standard in table 1 to this subpart. Additionally, you must record all periods when the TOC CEMS is inoperable. The Administrator may at any time require a report of these data. Periods of operation during which the operating parameter limits established during the most recent performance tests are exceeded are defined as follows:

(1) For absorbers:

(i) All 3-hour periods of operation during which the average absorbing liquid temperature was above the maximum absorbing liquid temperature established during the most recent performance test.

(ii) All 3-hour periods of operation during which the average absorbing liquid specific gravity was outside the exit specific gravity range (*i.e.,* more than 0.1 unit above, or more than 0.1 unit below, the average absorbing liquid specific gravity) established during the most recent performance test.

(2) For boilers or process heaters:

(i) Whenever there is a change in the location at which the vent stream is introduced into the flame zone as required under § 60.663a(b).

(ii) If the boiler or process heater has a design heat input capacity of less than 44 MW (150 million Btu/hr), then all 3-hour periods of operation during which the average firebox temperature was below the minimum firebox temperature during the most recent performance test.

(3) For catalytic incinerators:

(i) All 3-hour periods of operation during which the average temperature of the vent stream immediately before the catalyst bed is below the minimum temperature of the vent stream established during the most recent performance test.

(ii) All 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than the average temperature difference of the device established during the most recent performance test.

(4) For carbon adsorbers:

(i) All carbon bed regeneration cycles during which the total mass stream flow or the total volumetric stream flow was below the minimum flow established during the most recent performance test.

(ii) All carbon bed regeneration cycles during which the temperature of the carbon bed after regeneration (and after completion of any cooling cycle(s)) was greater than the maximum carbon bed temperature (in degrees Celsius) established during the most recent performance test.

(5) For condensers, all 3-hour periods of operation during which the average exit (product side) condenser operating temperature was above the maximum exit (product side) operating temperature established during the most recent performance test.

(6) For scrubbers used to control halogenated vent streams:

(i) All 3-hour periods of operation during which the average pH of the scrubber effluent is below the minimum pH of the scrubber effluent established during the most recent performance test.

(ii) All 3-hour periods of operation during which the average influent liquid flow to the scrubber is below the minimum influent liquid flow to the scrubber established during the most recent performance test.

(iii) All 3-hour periods of operation during which the average liquid-to-gas ratio flow of the scrubber is below the minimum liquid-to-gas ratio of the scrubber established during the most recent performance test.

(7) For thermal incinerators, all 3-hour periods of operation during which the average firebox temperature was

below the minimum firebox temperature established during the most recent performance test.

(8) For all other control devices, all periods (for the averaging time specified by the Administrator) when the operating parameter(s) established under § 60.663a(c) exceeded the operating limit established during the most recent performance test.

(d) You must keep up to date, readily accessible continuous records of the flow indication specified in table 2 to this subpart, as well as up-to-date, readily accessible records of all periods when the vent stream is diverted from the control device or recovery device or has no flow rate, including the records as specified in paragraphs (d)(1) and (2) of this section.

(1) For each flow event from a relief valve discharge subject to the requirements in § 60.662a(b)(1), you must include an estimate of the volume of gas, the concentration of TOC in the gas and the resulting emissions of TOC that released to the atmosphere using process knowledge and engineering estimates.

(2) For each flow event from a bypass line subject to the requirements in §§ 60.662a(b)(2) and 60.670a(e), you 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 or recovery device not meeting the requirements in this subpart, you must include an estimate of the volume of gas, the concentration of TOC in the gas and the resulting emissions of TOC that bypassed the control device or recovery device using process knowledge and engineering estimates.

(e) If you use a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater to comply with the TOC emission limit specified in Table 1 to this subpart, then you must keep an up-to-date, readily accessible record of all periods of operation of the boiler or process heater. (Examples of such records could include records of steam use, fuel use, or monitoring data collected pursuant to other State or Federal regulatory requirements.)

(f) If you use a flare to comply with the TOC emission standard specified in Table 1 to this subpart, then you must keep up-to-date, readily accessible records of 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 this chapter, as applicable; and all periods during the compliance determination when the pilot flame or flare flame is absent.

(g) For each maintenance vent opening subject to the requirements of § 60.662a(c), you must keep the applicable records specified in paragraphs (g)(1) through (5) of this section.

(1) You must maintain standard site procedures used to inventory equipment for safety purposes (*e.g.,* hot work or vessel entry procedures) to document the procedures used to meet the requirements in § 60.662a(c). 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 § 60.662a(c)(1)(i), and the lower explosive limit at the time of the vessel opening exceeds 10 percent, identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, and the lower explosive limit at the time of the vessel opening.

(3) If complying with the requirements of § 60.662a(c)(1)(ii), and either the vessel pressure at the time of the vessel opening exceeds 5 psig or the lower explosive limit at the time of the active purging was initiated exceeds 10 percent, identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, the pressure of the vessel or equipment at the time of discharge to the atmosphere and, if applicable, the lower explosive limit of the vapors in the equipment when active purging was initiated.

(4) If complying with the requirements of § 60.662a(c)(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 inventory procedures specified in paragraph (g)(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 (g)(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 § 60.662a(c)(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 lower explosive limit 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.

(h) If you seek to comply with the requirements of this subpart by complying with the design production capacity provision in § 60.660a(c)(4) you must keep up-to-date, readily accessible records of any change in equipment or process operation that increases the design production capacity of the process unit in which the affected facility is located.

(i) If you seek to comply with the requirements of this subpart by complying with the flow rate cutoff in § 60.660a(c)(5) or (6) you must keep up-to-date, readily accessible records to indicate that the vent stream flow rate is less than 0.008 scm/min (0.3 scf/min) or less than 0.001 lb/hr, and of any change in equipment or process operation that increases the operating vent stream flow rate, including a measurement of the new vent stream flow rate.

(j) You must submit to the Administrator semiannual reports of the information specified in paragraphs (j)(1) through (9) of this section. You are exempt from the reporting requirements specified in § 60.7(c). If there are no exceedances, periods, or events specified in paragraphs (j)(1) through (9) of this section that occurred during the reporting period, then you must include a statement in your report that no exceedances, periods, and events specified in paragraphs (j)(1) through (9) of this section occurred during the reporting period. The initial report must be submitted within 6 months after the initial start-up-date. On and after July 15, 2024 or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for 1 year, whichever date is later, you must submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (k) of this section. 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. All semiannual reports must include the following general information: company name, address (including county), and beginning and ending dates of the reporting period.

(1) Exceedances of monitored parameters recorded under paragraph (c) of this section. For each exceedance, the report must include a list of the affected facilities or equipment, the monitored parameter that was exceeded, the start date and time of the exceedance, the duration (in hours) of the exceedance, 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 exceedance (including unknown cause, if applicable), as applicable, and the corrective action taken.

(2) All periods recorded under paragraph (d) of this section when the vent stream is diverted from the control device or recovery device, or has no flow rate, including the information specified in paragraphs (j)(2)(i) through (iii) of this section.

(i) For periods when the flow indicator is not operating, report the identification of the flow indicator and the start date, start time, and duration in hours.

(ii) For each flow event from a relief valve discharge subject to the requirements in § 60.662a(b)(1), the semiannual report must include the identification of the relief valve, the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of TOC in the gas in parts per million by volume and the resulting mass emissions of TOC in pounds that released to the atmosphere.

(iii) For each flow event from a bypass line subject to the requirements in § 60.662a(b)(2) and § 670a(e)(2), the semiannual report must include the identification of the bypass line, the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of TOC in the gas in parts per million by volume and the resulting mass emissions of TOC in pounds that bypass a control device or recovery device.

(3) All periods when a boiler or process heater was not operating (considering the records recorded under paragraph (e) of this section), including the start date, start time, and duration in hours of each period.

(4) For each flare subject to the requirements in § 60.669a, the semiannual report must include an identification of the flare and the items specified in § 60.669a(l)(2).

(5) For each closed vent system subject to the requirements in § 60.670a, the semiannual report must include an identification of the closed vent system and the items specified in § 60.670a(i).

(6) Any change in equipment or process operation, as recorded under paragraph (h) of this section, that increases the design production capacity above the low capacity exemption level in § 60.660a(c)(4) and the new capacity resulting from the change for the distillation process unit containing the affected facility. These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. Unless the facility qualifies for an exemption under § 60.660a(c), the facility must begin compliance with the requirements set forth in § 60.662a.

(7) Any change in equipment or process operation that increases the operating vent stream flow rate above the low flow exemption level in § 60.660a(c)(5) or (6), including a measurement of the new vent stream flow rate, as recorded under paragraph (i) of this section. These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed with the same time period to verify the recalculated flow value. The performance test is subject to the requirements of § 60.8 and must be submitted according to paragraph (b)(1) of this section. Unless the facility qualifies for an exemption under § 60.660a(c), the facility must begin compliance with the requirements set forth in § 60.662a.

(8) Exceedances of the emission standard in Table 1 of this subpart as indicated by a 3-hour average of the TOC CEMS and recorded under paragraph (c) of this section. For each exceedance, the report must include a list of the affected facilities or equipment, the start date and time of the exceedance, the duration (in hours) of the exceedance, an estimate of the quantity in pounds of each regulated pollutant emitted over the emission limit, a description of the method used to estimate the emissions, the cause of the exceedance (including unknown cause, if applicable), as applicable, and the corrective action taken.

(9) Periods when the TOC CEMS was inoperative. For each period, the report must include a list of the affected facilities or equipment, the start date and time of the period, the duration (in hours) of the period, the cause of the inoperability (including unknown cause, if applicable), as applicable, and the corrective action taken.

(k) If you are required to submit notifications or reports following the procedure specified in this paragraph (k), you must submit notifications or 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 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 or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (k)(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 (k).

(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. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the SOCMI NSPS 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, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the SOCMI NSPS Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(l) If you are required to electronically submit notifications or reports through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with the electronic submittal requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (l)(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.

(m) If you are required to electronically submit notifications or reports through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with the electronic submittal requirement. To assert a claim of *force majeure,* you must meet the requirements outlined in paragraphs (m)(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.

(n) The requirements of paragraph (j) of this section remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with paragraph (j) of this section, provided that they comply with the requirements established by the State. The EPA will not approve a waiver of electronic reporting to the EPA in delegating enforcement authority. Thus, electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph cannot be used to relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

(o) If you seek to demonstrate compliance with § 60.660(c)(4), then you must submit to the Administrator an initial report detailing the design production capacity of the process unit.

(p) If you seek to demonstrate compliance with § 60.660(c)(5) or (6), then you must submit to the Administrator, following the procedures in paragraph (b)(1) of this section, an initial report including a flow rate measurement using the test methods specified in § 60.664a.

(q) The Administrator will specify appropriate reporting and recordkeeping requirements where the owner or operator of an affected facility complies with the standards specified under § 60.662a other than as provided under § 60.663a.

(r) 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.

§ 60.666a What do the terms associated with reconstruction mean for this subpart?

For purposes of this subpart "fixed capital cost of the new components," as used in § 60.15, includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following April 25, 2023. For purposes of this paragraph, "commenced" means that you have undertaken a continuous program of component replacement or that you have entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

§ 60.667a What are the chemicals that I must produce to be affected by subpart NNNa?

Chemical name	CAS No.*
Acetaldehyde	75–07–0
Acetaldol	107–89–1
Acetic acid	64–19–7
Acetic anhydride	108–24–7
Acetone	67–64–1
Acetone cyanohydrin	75–86–5
Acetylene	74–86–2
Acrylic acid	79–10–7
Acrylonitrile	107–13–1
Adipic acid	124–04–9
Adiponitrile	111–69–3
Alcohols, C-11 or lower, mixtures	
Alcohols, C-12 or higher, mixtures	
Allyl chloride	107–05–1
Amylene	513–35–9
Amylenes, mixed	
Aniline	62–53–3
Benzene	71–43–2
Benzenesulfonic acid	98–11–3
Benzenesulfonic acid $C_{10\text{-}16}$-alkyl derivatives, sodium salts	68081–81–2
Benzoic acid, tech	65–85–0
Benzyl chloride	100–44–7
Biphenyl	92–52–4
Bisphenol A	80–05–7
Brometone	76–08–4
1,3-Butadiene	106–99–0
Butadiene and butene fractions	
n-Butane	106–97–8
1,4-Butanediol	110–63–4
Butanes, mixed	
1-Butene	106–98–9
2-Butene	25167–67–3
Butenes, mixed	
n-Butyl acetate	123–86–4
Butyl acrylate	141–32–2
n-Butyl alcohol	71–36–3
sec-Butyl alcohol	78–92–2
tert-Butyl alcohol	75–65–0
Butylbenzyl phthalate	85–68–7
Butylene glycol	107–88–0
tert-Butyl hydroperoxide	75–91–2
2-Butyne-1,4-diol	110–65–6
Butyraldehyde	123–72–8
Butyric anhydride	106–31–0
Caprolactam	105–60–2
Carbon disulfide	75–15–0
Carbon tetrabromide	558–13–4
Carbon tetrachloride	56–23–5
Chlorobenzene	108–90–7
2-Chloro-4-(ethylamino)-6-(isopropylamino)-s-triazine	1912–24–9
Chloroform	67–66–3
p-Chloronitrobenzene	100–00–5
Chloroprene	126–99–8
Citric acid	77–92–9
Crotonaldehyde	4170–30–0
Crotonic acid	3724–65–0
Cumene	98–82–8
Cumene hydroperoxide	80–15–9
Cyanuric chloride	108–77–0
Cyclohexane	110–82–7
Cyclohexane, oxidized	68512–15–2
Cyclohexanol	108–93–0
Cyclohexanone	108–94–1
Cyclohexanone oxime	100–64–1
Cyclohexene	110–83–8
1,3-Cyclopentadiene	542–92–7

Chemical name	CAS No.*
Cyclopropane	75–19–4
Diacetone alcohol	123–42–2
Dibutanized aromatic concentrate	
1,4-Dichlorobutene	110–57–6
3,4-Dichloro-1-butene	64037–54–3
Dichlorodifluoromethane	75–71–8
Dichlorodimethylsilane	75–78–5
Dichlorofluoromethane	75–43–4
Dichlorohydrin	96–23–1
Diethanolamine	111–42–2
Diethylbenzene	25340–17–4
Diethylene glycol	111–46–6
Di-n-heptyl-n-nonyl undecyl phthalate	85–68–7
Di-isodecyl phthalate	26761–40–0
Diisononyl phthalate	28553–12–0
Dimethylamine	124–40–3
Dimethyl terephthalate	120–61–6
2,4-Dinitrotoluene	121–14–2
2,4-(and 2,6)-dinitrotoluene	121–14–2 606–20–2
Dioctyl phthalate	117–81–7
Dodecene	25378–22–7
Dodecylbenzene, non linear	
Dodecylbenzenesulfonic acid	27176–87–0
Dodecylbenzenesulfonic acid, sodium salt	25155–30–0
Epichlorohydrin	106–89–8
Ethanol	64–17–5
Ethanolamine	141–43–5
Ethyl acetate	141–78–6
Ethyl acrylate	140–88–5
Ethylbenzene	100–41–4
Ethyl chloride	75–00–3
Ethyl cyanide	107–12–0
Ethylene	74–85–1
Ethylene dibromide	106–93–4
Ethylene dichloride	107–06–2
Ethylene glycol	107–21–1
Ethylene glycol monobutyl	111–76–2
Ethylene glycol monoethyl ether	110–80–5
Ethylene glycol monoethyl ether acetate	111–15–9
Ethylene glycol monomethyl ether	109–86–4
Ethylene oxide	75–21–8
2-Ethylhexanal	26266–68–2
2-Ethylhexyl alcohol	104–76–7
(2-Ethylhexyl) amine	104–75–6
Ethylmethylbenzene	25550–14–5
6-Ethyl-1,2,3,4-tetrahydro 9,10-anthracenedione	15547–17–8
Formaldehyde	50–00–0
Glycerol	56–81–5
n-Heptane	142–82–5
Heptenes (mixed)	
Hexadecyl chloride	
Hexamethylene diamine	124–09–4
Hexamethylene diamine adipate	3323–53–3
Hexamethylenetetramine	100–97–0
Hexane	110–54–3
2-Hexenedinitrile	13042–02–9
3-Hexenedinitrile	1119–85–3
Hydrogen cyanide	74–90–8
Isobutane	75–28–5
Isobutanol	78–83–1
Isobutylene	115–11–7
Isobutyraldehyde	78–84–2
Isodecyl alcohol	25339–17–7
Isooctyl alcohol	26952–21–6
Isopentane	78–78–4
Isophthalic acid	121–91–5
Isoprene	78–79–5
Isopropanol	67–63–0
Ketene	463–51–4
Linear alcohols, ethoxylated, mixed	
Linear alcohols, ethoxylated, and sulfated, sodium salt, mixed	
Linear alcohols, sulfated, sodium salt, mixed	
Linear alkylbenzene	123–01–3

Chemical name	CAS No.*
Magnesium acetate	142–72–3
Maleic anhydride	108–31–6
Melamine	108–78–1
Mesityl oxide	141–79–7
Methacrylonitrile	126–98–7
Methanol	67–56–1
Methylamine	74–89–5
ar-Methylbenzenediamine	25376–45–8
Methyl chloride	74–87–3
Methylene chloride	75–09–2
Methyl ethyl ketone	78–93–3
Methyl iodide	74–88–4
Methyl isobutyl ketone	108–10–1
Methyl methacrylate	80–62–6
2-Methylpentane	107–83–5
1-Methyl-2-pyrrolidone	872–50–4
Methyl tert-butyl ether	
Naphthalene	91–20–3
Nitrobenzene	98–95–3
1-Nonene	27215–95–8
Nonyl alcohol	143–08–8
Nonylphenol	25154–52–3
Nonylphenol, ethoxylated	9016–45–9
Octene	25377–83–7
Oil-soluble petroleum sulfonate, calcium salt	
Oil-soluble petroleum sulfonate, sodium salt	
Pentaerythritol	115–77–5
n-Pentane	109–66–0
3-Pentenenitrile	4635–87–4
Pentenes, mixed	109–67–1
Perchloroethylene	127–18–4
Phenol	108–95–2
1-Phenylethyl hydroperoxide	3071–32–7
Phenylpropane	103–65–1
Phosgene	75–44–5
Phthalic anhydride	85–44–9
Propane	74–98–6
Propionaldehyde	123–38–6
Propionic acid	79–09–4
Propyl alcohol	71–23–8
Propylene	115–07–1
Propylene chlorohydrin	78–89–7
Propylene glycol	57–55–6
Propylene oxide	75–56–9
Sodium cyanide	143–33–9
Sorbitol	50–70–4
Styrene	100–42–5
Terephthalic acid	100–21–0
1,1,2,2-Tetrachloroethane	79–34–5
Tetraethyl lead	78–00–2
Tetrahydrofuran	109–99–9
Tetra (methyl-ethyl) lead	
Tetramethyl lead	75–74–1
Toluene	108–88–3
Toluene-2,4-diamine	95–80–7
Toluene-2,4-(and, 2,6)-diisocyanate (80/20 mixture)	26471–62–5
Tribromomethane	75–25–2
1,1,1-Trichloroethane	71–55–6
1,1,2-Trichloroethane	79–00–5
Trichloroethylene	79–01–6
Trichlorofluoromethane	75–69–4
1,1,2-Trichloro-1,2,2-trifluoroethane	76–13–1
Triethanolamine	102–71–6
Triethylene glycol	112–27–6
Vinyl acetate	108–05–4
Vinyl chloride	75–01–4
Vinylidene chloride	75–35–4
m-Xylene	108–38–3
o-Xylene	95–47–6
p-Xylene	106–42–3
Xylenes (mixed)	1330–20–7

Chemical name	CAS No.*
m-Xylenol	576–26–1

* CAS numbers refer to the Chemical Abstracts Registry numbers assigned to specific chemicals, isomers, or mixtures of chemicals. Some isomers or mixtures that are covered by the standards do not have CAS numbers assigned to them. The standards apply to all of the chemicals listed, whether CAS numbers have been assigned or not.

§ 60.668a [Reserved]

§ 60.669a What are my requirements if I use a flare to comply with this subpart?

(a) If you use a flare to comply with the TOC emission standard specified in Table 1 to this subpart, then you must meet the applicable requirements for flares as specified in §§ 63.670 and 63.671 of this chapter, including the provisions in tables 12 and 13 to part 63, subpart CC, of this chapter, 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 an affected facility, as determined on an annual average basis. For purposes of compliance with this paragraph (a), the following terms are defined in § 63.641 of this chapter: 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.

(b) When determining compliance with the pilot flame requirements specified in § 63.670(b) and (g) of this chapter, 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) of this chapter, the requirement effectively applies starting with the 15-minute block that includes a full 15 minutes of the flaring event. You are required to demonstrate compliance with the velocity and NHVcz requirements starting with the block that contains the fifteenth minute of a flaring event. You are 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) of this chapter, you must develop and implement the flare management plan no later than startup for a new flare that commenced construction on or after April 25, 2023.

(e) Instead of complying with § 63.670(o)(2)(iii) of this chapter, 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) following the procedures specified in § 60.665a(k).

(f) Section 63.670(o)(3)(ii) of this chapter and all references to it do not apply. Instead, you must comply with the maximum flare tip velocity operating limit at all times.

(g) Substitute ''affected facility'' 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 you must meet the following conditions:

(1) You are not required to comply with the flare tip velocity requirements in § 63.670(d) and (k) of this chapter;

(2) The NHVcz for pressure-assisted mulit-point flares is 800 Btu/scf;

(3) You must determine the 15-minute block average NHVvg using only the direct calculation method specified in in § 63.670(l)(5)(ii) of this chapter;

(4) Instead of complying with § 63.670(b) and (g) of this chapter, 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 you 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 deviation of the standard. Deviations in different 15-minute blocks from the same event are considered separate deviations. 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 you choose to conduct a cross-light performance demonstration as specified in this paragraph (i)(5), you 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 you conduct 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) You 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 part 63, subpart CC, of this chapter.

(7) If a pressure-assisted multi-point flare is operating under the requirements of an approved alternative means of emission limitations, you 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 you choose to determine compositional analysis for net heating value with a continuous process mass spectrometer, then you must comply with the requirements specified in paragraphs (j)(1) through (7) of this section.

(1) You must meet the requirements in § 63.671(e)(2) of this chapter. You 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, 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 NHVvg.

(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 Performance Specification 9 of appendix B of this part, 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 part 63, subpart CC, of this chapter, for the process mass spectrometer. You may use the alternative sampling line temperature allowed under Net Heating Value by Gas Chromatograph in table 13 to part 63, subpart CC, of this chapter.

(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 (j)(7).

Equation 1 to Paragraph (j)(7)

$$CE = \frac{C_m - C_a}{C_a} x\ 100 \text{ (Eq. 1)}$$

Where:

Cm = Average instrument response (ppm)
Ca = Certified cylinder gas value (ppm)

(k) If you use a gas chromatograph or mass spectrometer for compositional analysis for net heating value, then you 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 must be calculated using equation 2 to this paragraph (k).

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) of this chapter, you must comply with the reporting requirements specified in paragraphs (l)(1) and (2) of this section.

(1) The notification requirements specified in § 60.665a(a).

(2) The semiannual report specified in § 60.665a(j)(4) 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.

(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) of this chapter as applicable.

(iv) For flaring events meeting the criteria in § 63.670(o)(3) of this chapter 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) of this chapter 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) of this chapter, you 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) of this chapter

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. You 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 of appendix A–7 of this part, then the record must identify whether the visible emissions observation was performed, the results of each observation, total duration of observed visible emissions, and whether it was a 5-minute or 2-hour observation. 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) of this chapter, 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) of this chapter, 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) of this chapter. 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) this chapter, as applicable.

(6) All periods during which operating values are outside of the applicable operating limits specified in § 63.670(d) through (f) of this chapter and paragraph (i) of this section when regulated material is being routed to the flare.

(7) All periods during which you do not perform flare monitoring according to the procedures in § 63.670(g) through (j) of this chapter.

(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) of this chapter 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) of this chapter.

(14) For any corrective action analysis for which implementation of corrective actions are required in § 63.670(o)(5) of this chapter, 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) You may elect to comply with the alternative means of emissions limitation requirements specified in § 63.670(r) of this chapter in lieu of the requirements in § 63.670(d) through (f) of this chapter, as applicable. However, instead of complying with § 63.670(r)(3)(iii) of this chapter, you 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: SOCMI NSPS 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 this chapter.

(2) The last sentence of § 63.670(o)(6) of this chapter.

(3) The phrase "that were not caused by a *force majeure* event" in § 63.670(o)(7)(ii) of this chapter.

(4) The phrase "that were not caused by a *force majeure* event" in § 63.670(o)(7)(iv) of this chapter.

§ 60.670a What are my requirements for closed vent systems?

(a) Except as provided in paragraphs (f) and (g) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) through (3) of this section.

(1) Conduct an initial inspection according to the procedures in paragraph (b) of this section unless the closed vent system is operated and maintained under negative pressure;

(2) Conduct annual inspections according to the procedures in paragraph (b) of this section unless the closed vent system is operated and maintained under negative pressure; and

(3) Conduct annual inspections for visible, audible, or olfactory indications of leaks.

(b) You must inspect each closed vent system according to the procedures specified in paragraphs (b)(1) through (6) of this section.

(1) Inspections must be conducted in accordance with Method 21 of appendix A of this part.

(2)(i) Except as provided in paragraph (b)(2)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 of appendix A of this part, except the instrument response factor criteria in section 3.1.2(a) of Method 21 must be for the average composition of the process fluid not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts which are not organic hazardous air pollutants or volatile organic compounds, the average stream response factor must be calculated on an inert-free basis.

(ii) If no instrument is available at the plant site that will meet the performance criteria specified in paragraph (b)(2)(i) of this section, the instrument readings may be adjusted by multiplying by the average response factor of the process fluid, calculated on an inert-free basis as described in paragraph (b)(2)(i).

(3) The detection instrument must be calibrated before use on each day of its use by the procedures specified in Method 21 of appendix A of this part.

(4) Calibration gases must be as follows:

(i) Zero air (less than 10 parts per million hydrocarbon in air); and

(ii) Mixtures of methane in air at a concentration less than 2,000 parts per million. A calibration gas other than methane in air may be used if the instrument does not respond to methane or if the instrument does not meet the performance criteria specified in paragraph (b)(2)(i) of this section. In such cases, the calibration gas may be a mixture of one or more of the compounds to be measured in air.

(5) You may elect to adjust or not adjust instrument readings for background. If you elect to not adjust readings for background, all such instrument readings must be compared directly to the applicable leak definition to determine whether there is a leak.

(6) If you elect to adjust instrument readings for background, you must determine the background concentration using Method 21 of appendix A of this part. After monitoring each potential leak interface, subtract the background reading from the maximum concentration indicated by the instrument. The arithmetic difference between the maximum concentration indicated by the instrument and the background level must be compared with 500 parts per million for determining compliance.

(c) Leaks, as indicated by an instrument reading greater than 500 parts per million above background or by visual, audio, or olfactory inspections, must be repaired as soon as practicable, except as provided in paragraph (d) of this section.

(1) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(2) Repair must be completed no later than 15 calendar days after the leak is detected.

(d) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a shutdown, as defined in § 60.2, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment must be complete by the end of the next shutdown.

(e) For each closed vent system that contains bypass lines that could divert a vent stream away from the control device and to the atmosphere, you must comply with the provisions of either paragraph (e)(1) or (2), except as specified in paragraph (e)(3) of this section.

(1) Install, calibrate, maintain, and operate a flow indicator that determines whether vent stream flow is present at least once every 15 minutes. You must keep hourly records of whether the flow indicator 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 vent stream is diverted to the atmosphere or the flow indicator is not operating. The flow indicator must be installed at the entrance to any bypass line; or

(2) Secure the bypass line valve in the closed position with a car-seal or a lock-and-key type configuration. A visual inspection of the seal or closure mechanism must be performed at least once every month to ensure the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(3) 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 (e) of this section.

(f) Any parts of the closed vent system that are designated, as described in paragraph (h)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (a)(1) and (2) of this section if:

(1) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1) and (2) of this section; and

(2) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(g) Any parts of the closed vent system are designated, as described in paragraph (h)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (a)(1) and (2) of this section if:

(1) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) You have a written plan that requires inspection of the equipment at least once every 5 years.

(h) You must record the information specified in paragraphs (h)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each closed vent system that contains bypass lines that could divert a vent stream away from the control device and to the atmosphere, you must keep a record of the information specified in either paragraph (h)(3)(i) or (ii) of this section in addition to the

information specified in paragraph (h)(3)(iii) of this section.

(i) Hourly records of whether the flow indicator specified under paragraph (e)(1) of this section 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.

(ii) Where a seal mechanism is used to comply with paragraph (e)(2) of this section, hourly records of flow are not required. In such cases, you must record whether the monthly visual inspection of the seals or closure mechanisms has been done, and you must 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 configuration has been checked out, and records of any car-seal that has broken.

(iii) For each flow event from a bypass line subject to the requirements in paragraph (e) of this section, you 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, you must include an estimate of the volume of gas, the concentration of VOC in the gas and the resulting emissions of VOC that bypassed the control device using process knowledge and engineering estimates.

(4) For each inspection during which a leak is detected, a record of the information specified in paragraphs (h)(4)(i) through (viii) of this section.

(i) The instrument identification numbers; operator name or initials; and identification of the equipment.

(ii) The date the leak was detected and the date of the first attempt to repair the leak.

(iii) Maximum instrument reading measured by the method specified in paragraph (c) of this section after the leak is successfully repaired or determined to be nonrepairable.

(iv) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(v) The name, initials, or other form of identification of the owner or operator (or designee) whose decision it was that repair could not be effected without a shutdown.

(vi) The expected date of successful repair of the leak if a leak is not repaired within 15 calendar days.

(vii) Dates of shutdowns that occur while the equipment is unrepaired.

(viii) The date of successful repair of the leak.

(5) For each inspection conducted in accordance with paragraph (b) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(6) For each inspection conducted in accordance with paragraph (a)(3) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(i) The semiannual report specified in § 60.665a(j)(5) must include the items specified in paragraphs (i)(1) through (3) of this section.

(1) Reports of the times of all periods recorded under paragraph (h)(3)(i) of this section when the vent stream is diverted from the control device through a bypass line. Include the start date, start time, and duration in hours of each period.

(2) Reports of all periods recorded under paragraph (h)(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 of each period.

(3) For bypass lines subject to the requirements in paragraph (e) of this section, the semiannual reports must include the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of VOC in the gas in parts per million by volume and the resulting mass emissions of VOC 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.

TABLE 1 TO SUBPART NNNa OF PART 60—EMISSION LIMITS AND STANDARDS FOR VENT STREAMS

For each . . .	You must . . .
1. Vent stream	a. Reduce emissions of TOC (minus methane and ethane) by 98 weight-percent, or to a TOC (minus methane and ethane) concentration of 20 ppmv on a dry basis corrected to 3 percent oxygen by venting emissions through a closed vent system to any combination of non-flare control devices and/or recovery system and meet the requirements specified in § 60.663a and § 60.670a; *or* b. Reduce emissions of TOC (minus methane and ethane) by venting emissions through a closed vent system to a flare and meet the requirements specified in § 60.669a and § 60.670a.

TABLE 2 TO SUBPART NNNa OF PART 60—MONITORING REQUIREMENTS FOR COMPLYING WITH 98 WEIGHT-PERCENT REDUCTION OF TOTAL ORGANIC COMPOUNDS EMISSIONS OR A LIMIT OF 20 PARTS PER MILLION BY VOLUME

Non-flare control device or recovery device	Parameters to be monitored
1. All control and recovery devices	a. Presence of flow diverted to the atmosphere from the control and recovery device; *or* b. Monthly inspections of sealed valves
2. Absorber	a. Exit temperature of the absorbing liquid; *and* b. Exit specific gravity
3. 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 [a]
4. Catalytic incinerator	Temperature upstream and downstream of the catalyst bed
5. Carbon adsorber, regenerative	a. Total regeneration stream mass or volumetric flow during carbon bed regeneration cycle(s); *and* b. Temperature of the carbon bed after regeneration [and within 15 minutes of completing any cooling cycle(s)]

TABLE 2 TO SUBPART NNNa OF PART 60—MONITORING REQUIREMENTS FOR COMPLYING WITH 98 WEIGHT-PERCENT REDUCTION OF TOTAL ORGANIC COMPOUNDS EMISSIONS OR A LIMIT OF 20 PARTS PER MILLION BY VOLUME—Continued

Non-flare control device or recovery device	Parameters to be monitored
6. Carbon adsorber, non-regenerative or regenerated offsite	Breakthrough
7. Condenser	Exit (product side) temperature
8. Scrubber for halogenated vent streams	a. pH of scrubber effluent; *and* b. Scrubber liquid and gas flow rates
9. Thermal incinerator	Firebox temperature [a]
10. Control devices other than an incinerator, boiler, process heater, or flare; or recovery devices other than an absorber, condenser, or carbon adsorber.	As specified by the Administrator

[a] Monitor may be installed in the firebox or in the ductwork immediately downstream of the firebox before any substantial heat exchange is encountered.

TABLE 3 TO SUBPART NNNa OF PART 60—OPERATING PARAMETERS, OPERATING PARAMETER LIMITS AND DATA MONITORING, RECORDKEEPING AND COMPLIANCE FREQUENCIES

For the operating parameter applicable to you, as specified in table 2	You must establish the following operating parameter limit . . .	And you must monitor, record, and demonstrate continuous compliance using these minimum frequencies . . .		
		Data measurement	Data recording	Data averaging period for compliance
Absorbers				
1. Exit temperature of the absorbing liquid.	Maximum temperature	Continuous	Every 15 minutes	3-hour block average.
2. Exit specific gravity	Exit specific gravity range.	Continuous	Every 15 minutes	3-hour block average.
Boilers or process heaters (with a design heat input capacity <44MW and vent stream is not introduced with or as the primary fuel)				
3. Firebox temperature.	Minimum firebox temperature.	Continuous	Every 15 minutes	3-hour block average.
Catalytic incinerators				
4. Temperature in gas stream immediately before the catalyst bed.	Minimum temperature	Continuous	Every 15 minutes	3-hour block average.
5. Temperature difference between the catalyst bed inlet and the catalyst bed outlet.	Minimum temperature difference.	Continuous	Every 15 minutes	3-hour block average.
Carbon adsorbers				
6. Total regeneration stream mass flow during carbon bed regeneration cycle(s).	Minimum mass flow during carbon bed regeneration cycle(s).	Continuously during regeneration	Every 15 minutes during regeneration cycle.	Total flow for each regeneration cycle.
7. Total regeneration stream volumetric flow during carbon bed regeneration cycle(s).	Minimum volumetric flow during carbon bed regeneration cycle(s).	Continuously during regeneration	Every 15 minutes during regeneration cycle.	Total flow for each regeneration cycle.
8. Temperature of the carbon bed after regeneration [and within 15 minutes of completing any cooling cycle(s)].	Maximum temperature of the carbon bed after regeneration.	Continuously during regeneration and for 15 minutes after completing any cooling cycle(s).	Every 15 minutes during regeneration cycle (including any cooling cycle).	Average of regeneration cycle.
9. Breakthrough	As defined in § 60.661a.	As required by § 60.663a(a)(6)(iii)(B)	Each monitoring event	N/A.

TABLE 3 TO SUBPART NNNA OF PART 60—OPERATING PARAMETERS, OPERATING PARAMETER LIMITS AND DATA MONITORING, RECORDKEEPING AND COMPLIANCE FREQUENCIES—Continued

For the operating parameter applicable to you, as specified in table 2	You must establish the following operating parameter limit . . .	And you must monitor, record, and demonstrate continuous compliance using these minimum frequencies . . .		
		Data measurement	Data recording	Data averaging period for compliance
Condensers				
10. Exit (product side) temperature.	Maximum temperature	Continuous	Every 15 minutes	3-hour block average.
Scrubbers for halogenated vent streams				
11. pH of scrubber effluent.	Minimum pH	Continuous	Every 15 minutes	3-hour block average.
12. Influent liquid flow	Minimum inlet liquid flow.	Continuous	Every 15 minutes	3-hour block average.
13. Influent liquid flow rate and gas stream flow rate.	Minimum influent liquid-to-gas ratio.	Continuous	Every 15 minutes	3-hour block average.
Thermal incinerators				
14. Firebox temperature.	Minimum firebox temperature.	Continuous	Every 15 minutes	3-hour block average.
Control devices other than an incinerator, boiler, process heater, or flare; or recovery devices other than an absorber, condenser, or carbon adsorber				
15. As specified by the Administrator.	15. As specified by the Administrator.	15. As specified by the Administrator	15. As specified by the Administrator.	15. As specified by the Administrator.

TABLE 4 TO SUBPART NNNa OF PART 60—CALIBRATION AND QUALITY CONTROL REQUIREMENTS FOR CONTINUOUS PARAMETER MONITORING SYSTEM (CPMS)

If you monitor this parameter . . .	Your accuracy requirements are . . .	And your calibration requirements are . . .
1. Temperature	a. ± 1 percent over the normal range of temperature measured or 2.8 degrees Celsius (5 degrees Fahrenheit), whichever is greater, for non-cryogenic temperature ranges. b. ± 2.5 percent over the normal range of temperature measured or 2.8 degrees Celsius (5 degrees Fahrenheit), whichever is greater, for cryogenic temperature ranges.	c. Performance evaluation annually and following any period of more than 24 hours throughout which the temperature exceeded the maximum rated temperature of the sensor, or the data recorder was off scale. d. Visual inspections and checks of CPMS operation every 3 months, unless the CPMS has a redundant temperature sensor. e. Selection of a representative measurement location.
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.
3. 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.

TABLE 4 TO SUBPART NNNa 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 . . .
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.

■ 33. Revise the heading for subpart RRR to read as follows:

Subpart RRR—Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes After June 29, 1990, and on or Before April 25, 2023

■ 34. Amend § 60.700 by revising paragraphs (b) introductory text and (c)(5) and (8) and adding paragraph (e) to read as follows:

§ 60.700 Applicability and designation of affected facility.

* * * * *

(b) The affected facility is any of the following for which construction, modification, or reconstruction commenced after June 29, 1990, and on or before April 25, 2023:

(c) * * *

(5) If the vent stream from an affected facility is routed to a distillation unit subject to subpart NNN of this part or subpart NNNa of this part, and has no other releases to the air except for a pressure relief valve, the facility is exempt from all provisions of this subpart except for § 60.705(r).

* * * * *

(8) Each affected facility operated with a concentration of total organic compounds (TOC) (less methane and ethane) in the vent stream less than 300 ppmv as measured by Method 18 of appendix A–6 to this part or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in § 60.704(b)(4), or a concentration of TOC in the vent stream less than 150 ppmv as measured by Method 25A of appendix A–7 to this part is exempt from all provisions of this subpart except for the test method and procedure and the reporting and recordkeeping requirements in §§ 60.704(h) and 60.705(j), (l)(8), and (p).

* * * * *

(e) 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 this part or 40 CFR part 61 or 63, may elect to comply with the requirements in § 60.709a in lieu of all flare related requirements in any other regulation in this part or 40 CFR part 61 or 63.

■ 35. Amend § 60.701 by revising the definition of ''Flame zone'' as follows to read as follows:

§ 60.701 Definitions.

* * * * *

Flame zone means the portion of the combustion chamber in a boiler or process heater occupied by the flame envelope.

* * * * *

■ 36. Amend § 60.704 by revising paragraphs (b)(3), (b)(4) introductory text, (d), and (h)(2) and (3) to read as follows:

§ 60.704 Test methods and procedures.

* * * * *

(b) * * *

(3) The emission rate correction factor, integrated sampling and analysis procedures of Method 3B of appendix A–2 to this part, or the manual method in ANSI/ASME PTC 19.10–1981 incorporated by reference, see § 60.17), shall be used to determine the oxygen concentration (%O2d) for the purposes of determining compliance with the 20 ppmv limit. The sampling site shall be the same as that of the TOC samples, and the samples shall be taken during the same time that the TOC samples are taken. The TOC concentration corrected to 3 percent O2 (Cc) shall be computed using the following equation:

$$C_C = C_{TOC}\,\frac{17.9}{20.9 - \%O_{2d}}$$

Where:

C_c = Concentration of TOC corrected to 3 percent O_2, dry basis, ppm by volume.

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

$\%O_{2d}$ = Concentration of O_2, dry basis, percent by volume.

(4) Method 18 of appendix A–6 to this part to determine the concentration of TOC in the control device outlet and the concentration of TOC in the inlet when the reduction efficiency of the control device is to be determined. ASTM D6420–18 (incorporated by reference, see § 60.17) may be used in lieu of Method 18 of appendix A–6 to this part, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 may not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method.

* * * * *

(d) The following test methods, except as provided under § 60.8(b), shall be used for determining the net heating value of the gas combusted to determine compliance under § 60.702(b) and for determining the process vent stream TRE index value to determine compliance under §§ 60.700(c)(2) and 60.702(c).

(1)(i) Method 1 or 1A of appendix A–1 to this part, as appropriate, for selection of the sampling site. The sampling site for the vent stream flow rate and molar composition determination prescribed in § 60.704(d)(2) and (3) shall be, except for the situations outlined in paragraph (d)(1)(ii) of this section, prior to the inlet of any control device, prior to any postreactor dilution of the stream with air, and prior to any postreactor introduction of halogenated compounds into the process vent stream. No traverse site selection method is needed for vents smaller than 4 inches in diameter.

(ii) If any gas stream other than the reactor vent stream is normally conducted through the final recovery device:

(A) The sampling site for vent stream flow rate and molar composition shall be prior to the final recovery device and prior to the point at which any nonreactor stream or stream from a nonaffected reactor process is introduced.

(B) The efficiency of the final recovery device is determined by measuring the TOC concentration using Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in paragraph (b)(4) of this section, at the inlet to the final recovery device after the introduction of any vent stream and at the outlet of the final recovery device.

(C) This efficiency of the final recovery device shall be applied to the TOC concentration measured prior to the final recovery device and prior to the introduction of any nonreactor stream or stream from a nonaffected reactor process to determine the concentration of TOC in the reactor process vent stream from the final recovery device. This concentration of TOC is then used to perform the calculations outlined in paragraphs (d)(4) and (5) of this section.

(2) The molar composition of the process vent stream shall be determined as follows:

(i) Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in paragraph (b)(4) of this section, to measure the concentration of TOC including those containing halogens.

(ii) ASTM D1946–77 or 90 (Reapproved 1994) (incorporation by reference as specified in § 60.17 of this part) to measure the concentration of carbon monoxide and hydrogen.

(iii) Method 4 of appendix A–3 to this part to measure the content of water vapor.

(3) The volumetric flow rate shall be determined using Method 2, 2A, 2C, or 2D of appendix A–1 to this part, as appropriate.

(4) The net heating value of the vent stream shall be calculated using the following equation:

$$H_T = K_1 \sum_{j=1}^{n} C_j H_j \quad 1 - B_{ws}$$

Where:

H_T = Net heating value of the sample, MJ/scm, where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C, as in the definition of Q_s (vent stream flow rate).

K_1 = Constant, 1.740×10^{-7} (l/ppm) (g-mole/scm) (MJ/kcal), where standard temperature for (g-mole/scm) is 20 °C.

C_j = Concentration on a dry basis of compound j in ppm, as measured for organics by Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in paragraph (b)(4) of this section, and measured for hydrogen and carbon monoxide by ASTM D1946–77 or 90 (Reapproved 1994) (incorporated by reference, see § 60.17) as indicated in paragraph (d)(2) of this section.

H_j = Net heat of combustion of compound j, kcal/g-mole, based on combustion at 25 °C and 760 mm Hg. The heats of combustion of vent stream components would be required to be determined using ASTM D2382–76 or 88 or D4809–95 (incorporated by reference, see § 60.17) if published values are not available or cannot be calculated.

B_{ws} = Water vapor content of the vent stream, proportion by volume.

(5) The emission rate of TOC in the vent stream shall be calculated using the following equation:

$$E_{TOC} = K_2 \sum_{j=1}^{n} C_j M_j \; Q_s$$

Where:

E_{TOC} = Emission rate of TOC in the sample, kg/hr.

K_2 = Constant, 2.494×10^{-6} (l/ppm) (g-mole/scm) (kg/g) (min/hr), where standard temperature for (g-mole/scm) is 20 °C.

C_j = Concentration on a dry basis of compound j in ppm as measured by Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in paragraph (b)(4) of this section, as indicated in paragraph (d)(2) of this section.

M_j = Molecular weight of sample j, g/g-mole.

Q_s = Vent stream flow rate (dscm/min) at a temperature of 20 °C.

(6) The total vent stream concentration (by volume) of compounds containing halogens (ppmv, by compound) shall be summed from the individual concentrations of compounds containing halogens which were measured by Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in paragraph (b)(4) of this section.

* * * * *

(h) * * *

(2) Method 18 of appendix A–6 or Method 25A of appendix A–7 to this part shall be used to measure concentration. ASTM D6420–18 (incorporated by reference, see § 60.17) may be used in lieu of Method 18 as specified in paragraph (b)(4) of this section.

(3) Where Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in paragraph (b)(4) of this section, is used to qualify for the low concentration exclusion in § 60.700(c)(8), the procedures in paragraphs (b)(4)(i) and (iv) of this section shall be used to measure TOC concentration, and the procedures of paragraph (b)(3) of this section shall be used to correct the TOC concentration to 3 percent oxygen. To qualify for the exclusion, the results must demonstrate that the concentration of TOC, corrected to 3 percent oxygen, is below 300 ppm by volume.

* * * * *

■ 37. Amend § 60.705 by revising paragraphs (b) introductory text, (l), and (m) and adding paragraphs (u), (v), and (w) to read as follows:

§ 60.705 Reporting and recordkeeping requirements.

* * * * *

(b) Each owner or operator subject to the provisions of this subpart shall keep an up-to-date, readily accessible record of the following data measured during each performance test, and also include the following data in the report of the initial performance test required under § 60.8. Where a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used or where the reactor process vent stream is introduced as the primary fuel to any size boiler or process heater to comply with § 60.702(a), a report containing performance test data need not be submitted, but a report containing the information in paragraph (b)(2)(i) of this section is required. The same data specified in this section shall be submitted in the reports of all subsequently required performance tests where either the emission control efficiency of a combustion device, outlet concentration of TOC, or the TRE index value of a vent stream from a recovery system is determined. Beginning on July 15, 2024, owners and operators must submit the performance test report following the procedures specified in paragraph (u) of this section. Data collected using test methods that are 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, the owner or operator 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 an alternate electronic file.

* * * * *

(l) Each owner or operator that seeks to comply with the requirements of this subpart by complying with the requirements of § 60.700(c)(2), (3), or (4) or § 60.702 shall submit to the Administrator semiannual reports of the following recorded information. The initial report shall be submitted within 6 months after the initial start-up date. On and after July 15, 2025 or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for 1 year, whichever date is later, owners and operators must submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (u) of this section. 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.

(1) Exceedances of monitored parameters recorded under paragraphs (c), (f), and (g) of this section.

(2) All periods and duration recorded under paragraph (d) of this section when the vent stream is diverted from the control device to the atmosphere.

(3) All periods recorded under paragraph (e) of this section in which the pilot flame of the flare was absent.

(4) Any change in equipment or process operation that increases the operating vent stream flow rate above the low flow exemption level in § 60.700(c)(4), including a measurement of the new vent stream flow rate, as recorded under paragraph (i) of this section. These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed within the same time period to verify the recalculated flow value and to obtain the vent stream characteristics of heating value and E_{TOC}. The performance test is subject to the requirements of § 60.8, and the performance test must be reported according to paragraph (b) of this section. Unless the facility qualifies for an exemption under any of the exemption provisions listed in § 60.700(c), except for the total resource effectiveness index greater than 8.0 exemption in § 60.700(c)(2), the facility must begin compliance with the requirements set forth in § 60.702.

(5) Any change in equipment or process operation, as recorded under paragraph (i) of this section, that increases the design production capacity above the low capacity exemption level in § 60.700(c)(3) and the new capacity resulting from the change for the reactor process unit containing the affected facility. These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed within the same time period to obtain the vent stream flow rate, heating value, and E_{TOC}. The performance test is subject to the requirements of § 60.8, and the performance test must be reported according to paragraph (b) of this section. The facility must begin compliance with the requirements set forth in § 60.702 or § 60.700(d). If the facility chooses to comply with § 60.702, the facility may qualify for an exemption under § 60.700(c)(2), (4), or (8).

(6) Any recalculation of the TRE index value, as recorded under paragraph (g) of this section.

(7) All periods recorded under paragraph (d) of this section in which the seal mechanism is broken or the by-pass line valve position has changed. A record of the serial number of the car-seal or a record to show that the key to unlock the bypass line valve was checked out must be maintained to demonstrate the period, the duration, and frequency in which the bypass line was operated.

(8) Any change in equipment or process operation that increases the vent stream concentration above the low concentration exemption level in § 60.700(c)(8), including a measurement of the new vent stream concentration, as recorded under paragraph (j) of this section. These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. If the vent stream concentration is above 300 ppmv as measured using Method 18 of appendix A–6 to this part, or ASTM D6420–18 (incorporated by reference, see § 60.17) as specified in § 60.704(b)(4), or above 150 ppmv as measured using Method 25A of appendix A–7 to this part, a performance test must be completed within the same time period to obtain the vent stream flow rate, heating value, and ETOC. The performance test is subject to the requirements of § 60.8, and the performance test must be reported according to paragraph (b) of this section. Unless the facility qualifies for an exemption under any of the exemption provisions listed in § 60.700(c), except for the TRE index greater than 8.0 exemption in § 60.700(c)(2), the facility must begin compliance with the requirements set forth in § 60.702.

(m) The requirements of paragraph (l) of this section remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with paragraph (l), provided that they comply with the requirements established by the State. The EPA will not approve a waiver of electronic reporting to the EPA in delegating enforcement authority. Thus, electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph cannot be used to relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

* * * * *

(u) If an owner or operator is required to submit notifications or reports following the procedure specified in this paragraph (u), the owner or operator must submit notifications or 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 the owner or operator. Do not use CEDRI to submit information the owner or operator claims as CBI. Although the EPA does not expect persons to assert a claim of CBI, if an owner or operator wishes to assert a CBI claim for some of the information in the report or notification, the owner or operator must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (u)(1) and (2) of this section. Clearly mark the part or all of the information claimed 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. The owner or operator 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 (u).

(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. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the SOCMI NSPS Sector Lead. Owners and operators who do not have their own file sharing service and who require assistance with submitting large electronic files that exceed the file size limit for email attachments should email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If an owner or operator cannot transmit the file electronically, the owner or operator may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the SOCMI NSPS Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(v) Owners and operators required to electronically submit notifications or reports through CEDRI in the EPA's CDX may assert a claim of EPA system outage for failure to timely comply with the electronic submittal requirement. To assert a claim of EPA system outage, owners and operators must meet the requirements outlined in paragraphs (v)(1) through (7) of this section.

(1) The owner or operator 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) The owner or operator must submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) The owner or operator 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 the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the report was submitted.

(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.

(w) Owners and operators required to electronically submit notifications or reports through CEDRI in the EPA's CDX may assert a claim of *force majeure* for failure to timely comply with the electronic submittal requirement. To assert a claim of *force majeure,* owners and operators must meet the requirements outlined in paragraphs (w)(1) through (5) of this section.

(1) An owner or operator 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 the owner or operator 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) The owner or operator must submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) The owner or operator 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 the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the report was submitted.

(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.

■ 38. Amend § 60.708 by revising paragraph (b) to read as follows:

§ 60.708 Delegation of authority.

* * * * *

(b) Authorities which will not be delegated to States: § 60.703(e) and approval of an alternative to any electronic reporting to the EPA required by this subpart.

■ 39. Add subpart RRRa to read as follows:

Subpart RRRa—Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes for Which Construction, Reconstruction, or Modification Commenced After April 25, 2023

Sec.

§ 60.700a Am I subject to this subpart?

(a) You are subject to the provisions of this subpart if you operate an affected facility designated in paragraph (b) of this section that is part of a process unit that produces any of the chemicals listed in § 60.707a as a product, co-product, by-product, or intermediate, except as provided in paragraph (c) of this section.

(b) The affected facility is any of the following for which construction, modification, or reconstruction commenced after April 25, 2023:

(1) Each reactor process not discharging its vent stream into a recovery system.

(2) Each combination of a reactor process and the recovery system into which its vent stream is discharged.

(3) Each combination of two or more reactor processes and the common recovery system into which their vent streams are discharged.

(c) Exemptions from the provisions of paragraph (a) of this section are as follows:

(1) Any reactor process that is designed and operated as a batch operation is not an affected facility.

(2) Each affected facility in a process unit with a total design capacity for all chemicals produced within that unit of less than 1 gigagram per year (1,100 tons per year) is exempt from all provisions of this subpart except for the recordkeeping and reporting requirements in § 60.705a(h), (k)(6), and (p).

(3) Each affected facility operated with a vent stream flow rate less than 0.011 scm/min is exempt from all provisions of this subpart except for the test method and procedure and the recordkeeping and reporting requirements in §§ 60.704a(e) and 60.705a(i), (k)(7), and (q).

(4) If the vent stream from an affected facility is routed to a distillation unit subject to subpart NNNa of this part and has no other releases to the air except for a pressure relief valve, the facility is exempt from all provisions of this subpart except for § 60.705a(r).

(5) Any reactor process operating as part of a process unit which produces beverage alcohols, or which uses, contains, and produces no VOC is not an affected facility.

(6) Any reactor process that is subject to the provisions of subpart DDD is not an affected facility.

(7) Each affected facility operated with a concentration of total organic compounds (TOC) (less methane and ethane) in the vent stream less than 300 ppmv as measured by Method 18 or a concentration of TOC in the vent stream less than 150 ppmv as measured by Method 25A is exempt from all provisions of this subpart except for the test method and procedure and the reporting and recordkeeping requirements in § 60.704a(f) and § 60.705a(j), (k)(8), and (s).

(8) A vent stream going to a fuel gas system as defined in § 63.701a.

§ 60.701a What definitions must I know?

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

Batch operation means any noncontinuous reactor process that is not characterized by steady-state conditions and in which reactants are not added and products are not removed simultaneously.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator.

Breakthrough means the time when the level of 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.

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.

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 an incinerator, flare, boiler, or process heater, used for combustion of a vent stream discharged from the process vent.

Continuous recorder means a data recording device recording an instantaneous data value at least once every 15 minutes.

Flame zone means the portion of the combustion chamber in a boiler or process heater occupied by the flame envelope.

Flow indicator means a device which indicates whether gas flow is 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.

Halogenated vent stream means any vent stream determined to have a total concentration (by volume) of compounds containing halogens of 20 ppmv (by compound) or greater.

Incinerator means an enclosed combustion device that is used for destroying organic compounds. If there is energy recovery, the energy recovery section and the combustion chambers are not of integral design. That is, the energy recovery section and the combustion section are not physically formed into one manufactured or assembled unit but are joined by ducts or connections carrying flue gas.

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.

Primary fuel means the fuel fired through a burner or a number of similar burners. The primary fuel provides the principal heat input to the device, and the amount of fuel is sufficient to sustain operation without the addition of other fuels.

Process heater means a device that transfers heat liberated by burning fuel directly to process streams or to heat transfer liquids other than water.

Process unit means equipment assembled and connected by pipes or ducts to produce, as intermediates or final products, one or more of the chemicals in § 60.707a. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient product storage facilities.

Product means any compound or chemical listed in § 60.707a which is produced for sale as a final product as that chemical, or for use in the production of other chemicals or compounds. By-products, co-products, and intermediates are considered to be products.

Reactor processes are unit operations in which one or more chemicals, or reactants other than air, are combined or decomposed in such a way that their molecular structures are altered and one or more new organic compounds are formed.

Recovery device means an individual unit of equipment, such as an absorber, carbon adsorber, or condenser, capable of and used for the purpose of recovering chemicals for use, reuse, or sale.

Recovery system means an individual recovery device or series of such devices applied to the same vent stream.

Relief valve means a valve used only to release an unplanned, nonroutine discharge. A relief valve discharge results from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause that requires immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage.

Secondary fuel means a fuel fired through a burner other than a primary fuel burner. The secondary fuel may provide supplementary heat in addition to the heat provided by the primary fuel.

Total organic compounds or TOC means those compounds measured according to the procedures of Method 18 of appendix A–6 of this part or the concentration of organic compounds measured according to the procedures in Method 21 or Method 25A of appendix A–7 of this part.

Vent stream means any gas stream discharged directly from a reactor process to the atmosphere or indirectly to the atmosphere after diversion through other process equipment. The vent stream excludes and equipment leaks, including, but not limited to, pumps, compressors, and valves.

§ 60.702a What standards and associated requirements must I meet?

(a) You must comply with the emission limits and standards specified in Table 1 to this subpart and the requirements specified in paragraphs (b) and (c) of this section for each vent stream on and after the date on which the initial performance test required by §§ 60.8 and 60.704a is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after the initial start-up, whichever date comes first. The standards in this section apply at all times, including periods of startup, shutdown and malfunction. As provided in § 60.11(f), this provision supersedes the exemptions for periods of startup, shutdown and malfunction in the general provisions in subpart A of this part.

(b) The following release events from an affected facility are a violation of the emission limits and standards specified in table 1 to this subpart.

(1) Any relief valve discharge to the atmosphere of a vent stream.

(2) The use of a bypass line at any time on a closed vent system to divert emissions to the atmosphere, or to a control device or recovery device not meeting the requirements specified in § 60.703a.

(c) You may designate a vent stream 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. You must comply with the applicable requirements in paragraphs (c)(1) through (3) of this section for each maintenance vent. Any vent stream designated as a maintenance vent is only subject to the maintenance vent provisions in this paragraph (c) and the associated recordkeeping and reporting requirements in § 60.705a(g), respectively.

(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 § 60.709a, as applicable, or using any combination of a non-flare control device or recovery device meeting the requirements in table 1 to this subpart until one of the following conditions, as applicable, is met.

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

(ii) If there is no ability to measure the LEL of the vapor in the equipment based on the design of the equipment, the pressure in the equipment served by the maintenance vent is reduced to 5 pounds per square inch gauge (psig) or less. Upon opening the maintenance vent, active purging of the equipment cannot be used until the LEL of the vapors in the maintenance vent (or inside the equipment if the maintenance is a hatch or similar type of opening) is less than 10 percent.

(iii) The equipment served by the maintenance vent contains less than 50 pounds of total VOC.

(iv) 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 (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 (c)(1)(iii) of this section, you must determine the LEL or, if applicable, equipment pressure using process instrumentation or portable measurement devices and follow procedures for calibration and maintenance according to manufacturer's specifications.

(3) For maintenance vents complying with the alternative in paragraph (c)(1)(iii) of this section, you 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.

§ 60.703a What are my monitoring, installation, operation, and maintenance requirements?

(a) Except as specified in paragraphs (a)(5) through (7) of this section, if you use a non-flare control device or recovery system to comply with the TOC emission limit specified in table 1 to this subpart, then you must comply with paragraphs (a)(1) through (4), (b), and (c) of this section.

(1) Install a continuous parameter monitoring system(s) (CPMS) and monitor the operating parameter(s) applicable to the control device or recovery system as specified in table 2 to this subpart or established according to paragraph (c) of this section.

(2) Establish the applicable minimum, maximum, or range for the operating parameter limit as specified in Table 3 to this subpart or established according to paragraph (c) of this section by calculating the value(s) as the arithmetic average of operating parameter measurements recorded during the three test runs conducted for the most recent performance test. You may operate outside of the established operating parameter limit(s) during subsequent performance tests in order to establish new operating limits. You must include the updated operating limits with the performance test results submitted to the Administrator pursuant to § 60.705a(b). Upon establishment of a new operating limit, you must thereafter operate under the new operating limit. If the Administrator determines that you did not conduct the performance test in accordance with the applicable requirements or that the operating limit established during the performance test does not correspond to the conditions specified in § 60.704a(a), then you must conduct a new performance test and establish a new operating limit.

(3) Monitor, record, and demonstrate continuous compliance using the minimum frequencies specified in Table 3 to this subpart or established according to paragraph (c) of this section.

(4) Comply with the calibration and quality control requirements as specified in table 4 to this subpart or established according to paragraph (c) of this section that are applicable to the CPMS used.

(5) Any vent stream introduced with primary fuel into a boiler or process heater is exempt from the requirements specified in paragraphs (a)(1) through (4) of this section.

(6) If you vent 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 install a system of two or more adsorber units in series and comply with the requirements specified in paragraphs (a)(6)(i) through (iii) of this section in addition to the requirements specified in paragraphs (a)(1) through (4) 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 TOC concentration through a sample port at the outlet of the first adsorber bed in series according to the schedule in paragraph (a)(6)(iii)(B) of this section. You must measure the concentration of TOC using either a portable analyzer, in accordance with Method 21 of appendix A–7 of this part using methane, propane, or isobutylene as the calibration gas or Method 25A of appendix A–7 of this part using methane or propane as the calibration gas.

(iii) Comply with paragraph (a)(6)(iii)(A) of this section and comply with the monitoring frequency according to paragraph (a)(6)(iii)(B) of this section.

(A) The first adsorber in series must be replaced immediately when breakthrough, as defined in § 60.611a, 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 (a)(6)(iii)(A), "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. You 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)(6)(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.

(7) If you install a continuous emissions monitoring system (CEMS) to demonstrate compliance with the TOC standard in Table 1 of this subpart, you must comply with the requirements specified in § 60.704a(g) in lieu of the requirements specified in paragraphs (a)(1) through (4) and (c) of this section.

(b) If you vent emissions through a closed vent system to a boiler or process heater, then the vent stream must be introduced into the flame zone of the boiler or process heater.

(c) If you seek to demonstrate compliance with the standards specified under § 60.702a with control devices other than an incinerator, boiler, process heater, or flare; or recovery devices other than an absorber, condenser, or carbon adsorber, you shall provide to the Administrator prior to conducting the initial performance test information describing the operation of the control device or recovery device and the parameter(s) which would indicate proper operation and maintenance of the device and how the parameter(s) are indicative of control of TOC emissions. The Administrator may request further information and will specify appropriate monitoring procedures or requirements, including operating parameters to be monitored, averaging times for determining compliance with the operating parameter limits, and ongoing calibration and quality control requirements.

§ 60.704a What test methods and procedures must I use to determine compliance with the standards?

(a) For the purpose of demonstrating compliance with the emission limits and standards specified in table 1 to this subpart, all affected facilities must be run at full operating conditions and flow rates during any performance test. Performance tests are not required if you determine compliance using a CEMS that meets the requirements outlined in paragraph (g) of this section.

(1) Conduct initial performance tests no later than the date required by § 60.8(a).

(2) Conduct subsequent performance tests no later than 60 calendar months after the previous performance test.

(b) The following methods in appendix A to this part, except as provided in § 60.8(b), must be used as reference methods to determine compliance with the emission limit or percent reduction efficiency specified in table 1 to this subpart for non-flare control devices and/or recovery systems.

(1) Method 1 or 1A of appendix A–1 to this part, as appropriate, for selection of the sampling sites. The inlet sampling site for determination of vent stream molar composition or TOC (less methane and ethane) reduction efficiency shall be prior to the inlet of the control device or, if equipped with a recovery system, then prior to the inlet of the first recovery device in the recovery system.

(2) Method 2, 2A, 2C, or 2D of appendix A–1 to this part, as appropriate, for determination of the gas volumetric flow rates.

(3) Method 3A of appendix A–2 to this part or the manual method in ANSI/ASME PTC 19.10–1981—Part 10 (incorporated by reference, see § 60.17) must be used to determine the oxygen concentration (%O2d) for the purposes of determining compliance with the 20 ppmv limit. The sampling site must be the same as that of the TOC samples, and the samples must be taken during the same time that the TOC samples are taken. The TOC concentration corrected to 3 percent O_2 (Cc) must be computed using the following equation:

Equation 1 to Paragraph (b)(3)

$$C_C = C_{TOC} \frac{17.9}{20.9 - \%O_{2d}}$$

Where:

C_c = Concentration of TOC corrected to 3 percent O_2, dry basis, ppm by volume.
C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.
$\%O_{2d}$ = Concentration of O_2, dry basis, percent by volume.

(4) Method 18 of appendix A–6 to this part to determine the concentration of TOC in the control device outlet or in the outlet of the final recovery device in a recovery system, and to determine the concentration of TOC in the inlet when the reduction efficiency of the control device or recovery system is to be determined. ASTM D6420–18 (incorporated by reference, see § 60.17) 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 may not be used for methane and ethane; and ASTM D6420–18 must not be used as a total VOC method.

(i) The minimum sampling time for each run must be 1 hour in which either an integrated sample or at least four grab samples must be taken. If grab sampling is used, then the samples must be taken at approximately 15-minute intervals.

(ii) The emission reduction (R) of TOC (minus methane and ethane) must be determined using the following equation:

Equation 2 to Paragraph (b)(4)(ii)

$$R = \frac{E_i - E_o}{E_i} \times 100$$

Where:

R = Emission reduction, percent by weight.
E_i = Mass rate of TOC entering the control device or recovery system, kg TOC/hr.
E_o = Mass rate of TOC discharged to the atmosphere, kg TOC/hr.

(iii) The mass rates of TOC (E_i, E_o) must be computed using the following equations:

Equations 3 and 4 to Paragraph (b)(4)(iii)

$$E_i = K_2 \sum_{j=1}^{n} C_{ij} M_{ij} Q_i$$

$$E_i = K_2 \sum_{j=1}^{n} C_{oj} M_{ij} Q_o$$

Where:

C_{ij}, C_{oj} = Concentration of sample component "j" of the gas stream at the inlet and outlet of the control device or recovery system, respectively, dry basis, ppm by volume.
M_{ij}, M_{oj} = Molecular weight of sample component "j" of the gas stream at the inlet and outlet of the control device or recovery system, respectively, g/g-mole (lb/lb-mole).
Q_i, Q_o = Flow rate of gas stream at the inlet and outlet of the control device or recovery system, respectively, dscm/min (dscf/hr).
K_2 = Constant, $2.494 \times 10^{\text{minus;6}}$ (l/ppm) (g-mole/scm) (kg/g) (min/hr), where standard temperature for (g-mole/scm) is 20 °C (metric units); or
= Constant, $1.557 \times 10 - 7$ (1/ppm)(lb-mole/scf)(min/hr), where standard temperature for (lb-mole/scf) is 68 °F (English units).

(iv) The TOC concentration (C_{TOC}) is the sum of the individual components and must be computed for each run using the following equation:

Equation 5 to Paragraph (b)(4)(iv)

$$C_{TOC} = \sum_{j=1}^{n} C_j$$

Where:

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

C_j = Concentration of sample components "j", dry basis, ppm by volume.

n = Number of components in the sample.

(c) The requirement for initial and subsequent performance tests are waived, in accordance with § 60.8(b), for the following:

(1) When a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to seek compliance with § 60.702a(a).

(2) When a vent stream is introduced into a boiler or process heater with the primary fuel.

(3) 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 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 40 CFR 63.1207(j) and complies with the requirements of 40 CFR part 63, subpart EEE; or

(iv) Complies with 40 CFR part 63, subpart EEE, and will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date the owner or operator would have been required to submit the initial performance test report for this subpart.

(4) The Administrator reserves the option to require testing at such other times as may be required, as provided for in section 114 of the Act.

(d) For purposes of complying with the 98 weight-percent reduction in § 60.702a(a), if the vent stream entering a boiler or process heater with a design capacity less than 44 MW (150 million Btu/hour) is introduced with the combustion air or as secondary fuel, the weight-percent reduction of TOC (minus methane and ethane) across the combustion device shall be determined by comparing the TOC (minus methane and ethane) in all combusted vent streams, primary fuels, and secondary fuels with the TOC (minus methane and ethane) exiting the combustion device.

(e) Any owner or operator subject to the provisions of this subpart seeking to demonstrate compliance with § 60.700a(c)(3) shall use Method 2, 2A, 2C, or 2D of appendix A–1 to this part, as appropriate, for determination of volumetric flow rate. The owner or operator must conduct three velocity traverses and determine the volumetric flow rate for each traverse. If the pipe or duct is smaller than four inches in diameter, the owner operator may conduct the measurement at the centroid of the duct instead of conducting a traverse; the measurement period must be at least five minutes long and data must be recorded at least once every 30 seconds. Owners and operators who conduct the determination with Method 2A or 2D must record volumetric flow rate every 30 seconds for at least five minutes.

(f) Each owner or operator seeking to demonstrate that a reactor process vent stream has a TOC concentration for compliance with the low concentration exemption in § 60.700a(c)(7) shall conduct an initial test to measure TOC concentration.

(1) The sampling site shall be selected as specified in paragraph (d)(1)(i) of this section.

(2) Method 18 of appendix A–6 or Method 25A of appendix A–7 to this part shall be used to measure concentration. ASTM D6420–18 (incorporated by reference, see § 60.17) 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 may not be used for methane and ethane; and ASTM D6420–18 must not be used as a total VOC method.

(3) Where Method 18 of appendix A–6 to this part is used to qualify for the low concentration exclusion in § 60.700a(c)(7), the procedures in paragraphs (b)(4)(i) and (iv) of this section shall be used to measure TOC concentration, and the procedures of paragraph (b)(3) of this section shall be used to correct the TOC concentration to 3 percent oxygen. To qualify for the exclusion, the results must demonstrate that the concentration of TOC, corrected to 3 percent oxygen, is below 300 ppm by volume.

(4) Where Method 25A of appendix A–7 to this part is used, the following procedures shall be used to calculate ppm by volume TOC concentration, corrected to 3 percent oxygen:

(i) Method 25A of appendix A–7 to this part shall be used only if a single organic compound is greater than 50 percent of total TOC, by volume, in the reactor process vent stream. This compound shall be the principal organic compound.

(ii) The principal organic compound may be determined by either process knowledge or test data collected using an appropriate EPA Reference Method. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current reactor process vent stream conditions.

(iii) The principal organic compound shall be used as the calibration gas for Method 25A of appendix A–7 to this part.

(iv) The span value for Method 25A of appendix A–7 to this part shall be 300 ppmv.

(v) Use of Method 25A of appendix A–7 to this part is acceptable if the response from the high-level calibration gas is at least 20 times the standard deviation of the response from the zero calibration gas when the instrument is zeroed on the most sensitive scale.

(vi) The owner or operator shall demonstrate that the concentration of TOC including methane and ethane measured by Method 25A of appendix A–7 to this part, corrected to 3 percent oxygen, is below 150 ppm by volume to qualify for the low concentration exclusion in § 60.700a(c)(7).

(vii) The concentration of TOC shall be corrected to 3 percent oxygen using the procedures and equation in paragraph (b)(3) of this section.

(g) If you use a CEMS to demonstrate initial and continuous compliance with the TOC standard in table 1 of this subpart, each CEMS must be installed, operated and maintained according to the requirements in § 60.13 and paragraphs (f)(1) through (5) of this section.

(1) You must use a CEMS that is capable of measuring the target analyte(s) as demonstrated using either process knowledge of the control device inlet stream or the screening procedures of Method 18 of appendix A–6 to this

part on the control device inlet stream. If your CEMS is located after a combustion device and inlet stream to that device includes methanol or formaldehyde, you must use a CEMS which meets the requirements in Performance Specifications 9 or 15 of appendix B to this part.

(2) Each CEMS must be installed, operated, and maintained according to the applicable performance specification of appendix B of this part and the applicable quality assurance procedures of appendix F to this part. Locate the sampling probe or other interface at a measurement location such that you obtain representative measurements of emissions from the affected facility.

(3) Conduct a performance evaluation of each CEMS within 180 days of installation of the monitoring system. Conduct subsequent performance evaluations of the CEMS no later than 12 calendar months after the previous performance evaluation. The results each performance evaluation must be submitted in accordance with § 60.705a(b)(1).

(4) You must determine TOC concentration according to one of the following options. The span value of the TOC CEMS must be approximately 2 times the emission standard specified in table 1 of this subpart.

(i) For CEMS meeting the requirements of Performance Specification 15 of appendix B to this part, determine the target analyte(s) for calibration using either process knowledge of the control device inlet stream or the screening procedures of Method 18 of appendix A–6 to this part on the control device inlet stream. The individual analytes used to quantify TOC must represent 98 percent of the expected mass of TOC present in the stream. Report the results of TOC as equivalent to carbon (C1).

(ii) For CEMS meeting the requirements of Performance Specification 9 of appendix B to this part, determine the target analyte(s) for calibration using either process knowledge of the control device inlet stream or the screening procedures of Method 18 of appendix A–6 to this part on the control device inlet stream. The individual analytes used to quantify TOC must represent 98 percent of the expected mass of TOC present in the stream. Report the results of TOC as equivalent to carbon (C1).

(iii) For CEMS meeting the requirements of Performance Specification 8 of appendix B to this part used to monitor performance of a combustion device, calibrate the instrument on the predominant organic HAP and report the results as carbon (C1), and use Method 25A of appendix A–7 to this part as the reference method for the relative accuracy tests. You must also comply with procedure 1 of appendix F to this part.

(iv) For CEMS meeting the requirements of Performance Specification 8 of appendix B to this part used to monitor performance of a noncombustion device, determine the predominant organic compound using either process knowledge or the screening procedures of Method 18 of appendix A–6 to this part on the control device inlet stream. Calibrate the monitor on the predominant organic compound and report the results as C_1. Use Method 25A of appendix A–7 to this part as the reference method for the relative accuracy tests. You must also comply with procedure 1 of appendix F to this part.

(5) You must determine stack oxygen concentration at the same location where you monitor TOC concentration with a CEMS that meets the requirements of Performance Specification 3 of appendix B of this part. The span value of the oxygen CEMS must be approximately 25 percent oxygen. Use Method 3A of appendix A–2 to this part as the reference method for the relative accuracy tests.

(6) You must maintain written procedures for your CEMS. At a minimum, the procedures must include the information in paragraph (f)(6)(i) through (vi) of this section:

(i) Description of CEMS installation location.

(ii) Description of the monitoring equipment, including the manufacturer and model number for all monitoring equipment components and the span of the analyzer.

(iii) Routine quality control and assurance procedures.

(iv) Conditions that would trigger a CEMS performance evaluation, which must include, at a minimum, a newly installed CEMS; a process change that is expected to affect the performance of the CEMS; and the Administrator's request for a performance evaluation under section 114 of the Clean Air Act.

(v) Ongoing operation and maintenance procedures.

(vi) Ongoing recordkeeping and reporting procedures.

§ 60.705a What records must I keep and what reports must I submit?

(a) You must notify the Administrator of the specific provisions in table 1 to this subpart or § 60.702a(c) with which you have elected to comply. Notification shall be submitted with the notification of initial start-up required by § 60.7(a)(3). If you elect at a later date to comply with an alternative provision of § 60.702a, then you must notify the Administrator 90 days before implementing a change and, upon implementing the change, you must conduct a performance as specified by § 60.704a within 180 days.

(b) If you use a non-flare control device or recovery system to comply with the TOC emission limit specified in table 1 to this subpart, then you must keep an up-to-date, readily accessible record of the data measured during each performance test to show compliance with the TOC emission limit. You must also include all of the data you use to comply with § 60.703a(a)(2). The same data specified in this paragraph must also be submitted in the initial performance test required in § 60.8 and the reports of all subsequently required performance tests where either the emission reduction efficiency of a combustion device or recovery system or outlet concentration of TOC is determined. Alternatively, you must keep records of each CEMS performance evaluation.

(1) Within 60 days after the date of completing each performance test or CEMS performance evaluation required by this subpart, you must submit the results of the performance test or performance evaluation following the procedures specified in paragraph (l) of this section. Data collected using test methods and performance evaluations of CEMS measuring relative accuracy test audit (RATA) pollutants 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 or performance evaluation 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 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.

(2) If you use a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater to comply with the TOC emission limit specified in table 1 to this subpart, then you are not required to submit a report containing performance test data; however, you

must submit a description of the location at which the vent stream is introduced into the boiler or process heater.

(c) If you use a non-flare control device or recovery system to comply with the TOC emission limit specified in table 1 to this subpart, then you must keep up-to-date, readily accessible records of periods of operation during which the operating parameter limits established during the most recent performance test are exceeded or periods of operation where the TOC CEMS, averaged on a 3-hour block basis, indicate an exceedance of the emission standard in table 1 of this subpart. Additionally, you must record all periods when the TOC CEMS is inoperable. The Administrator may at any time require a report of these data. Periods of operation during which the operating parameter limits established during the most recent performance tests are exceeded are defined as follows:

(1) For absorbers:

(i) All 3-hour periods of operation during which the average absorbing liquid temperature was above the maximum absorbing liquid temperature established during the most recent performance test; and

(ii) All 3-hour periods of operation during which the average absorbing liquid specific gravity was outside the exit specific gravity range (*i.e.,* more than 0.1 unit above, or more than 0.1 unit below, the average absorbing liquid specific gravity) established during the most recent performance test.

(2) For boilers or process heaters:

(i) Whenever there is a change in the location at which the vent stream is introduced into the flame zone as required under § 60.703a(b); and

(ii) If the boiler or process heater has a design heat input capacity of less than 44 MW (150 million Btu/hr), then all 3-hour periods of operation during which the average firebox temperature was below the minimum firebox temperature during the most recent performance test.

(3) For catalytic incinerators:

(i) All 3-hour periods of operation during which the average temperature of the vent stream immediately before the catalyst bed is below the minimum temperature of the vent stream established during the most recent performance test.

(ii) All 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than the average temperature difference of the device established during the most recent performance test.

(4) For carbon adsorbers:

(i) All carbon bed regeneration cycles during which the total mass stream flow or the total volumetric stream flow was below the minimum flow established during the most recent performance test, or

(ii) All carbon bed regeneration cycles during which the temperature of the carbon bed after regeneration (and after completion of any cooling cycle(s)) was greater than the maximum carbon bed temperature (in degrees Celsius) established during the most recent performance test.

(5) For condensers, all 3-hour periods of operation during which the average exit (product side) condenser operating temperature was above the maximum exit (product side) operating temperature established during the most recent performance test.

(6) For scrubbers used to control halogenated vent streams:

(i) All 3-hour periods of operation during which the average pH of the scrubber effluent is below the minimum pH of the scrubber effluent established during the most recent performance test,

(ii) All 3-hour periods of operation during which the average influent liquid flow to the scrubber is below the minimum influent liquid flow to the scrubber established during the most recent performance test, or

(iii) All 3-hour periods of operation during which the average liquid-to-gas ratio flow of the scrubber is below the minimum liquid-to-gas ratio of the scrubber established during the most recent performance test.

(7) For thermal incinerators, all 3-hour periods of operation during which the average firebox temperature was below the minimum firebox temperature established during the most recent performance test.

(8) For all other control devices, all periods (for the averaging time specified by the Administrator) when the operating parameter(s) established under § 60.703a(c) exceeded the operating limit established during the most recent performance test.

(d) You must keep up-to-date, readily accessible continuous records of the flow indication specified in table 2 to this subpart, as well as up-to-date, readily accessible records of all periods when the vent stream is diverted from the control device or recovery device or has no flow rate, including the records as specified in paragraphs (d)(1) and (2) of this section.

(1) For each flow event from a relief valve discharge subject to the requirements in § 60.702a(b)(1), you must include an estimate of the volume of gas, the concentration of TOC in the gas and the resulting emissions of TOC that released to the atmosphere using process knowledge and engineering estimates.

(2) For each flow event from a bypass line subject to the requirements in §§ 60.702a(b)(2) and 60.710a(e), you 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 or recovery device not meeting the requirements in this subpart, you must include an estimate of the volume of gas, the concentration of TOC in the gas and the resulting emissions of TOC that bypassed the control device or recovery device using process knowledge and engineering estimates.

(e) If you use a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater to comply with the TOC emission limit specified in table 1 to this subpart, then you must keep an up-to-date, readily accessible record of all periods of operation of the boiler or process heater. (Examples of such records could include records of steam use, fuel use, or monitoring data collected pursuant to other State or Federal regulatory requirements).

(f) If you use a flare to comply with the TOC emission standard specified in table 1 to this subpart, then you must keep up-to-date, readily accessible records of 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 part 63, subpart CC of this chapter, as applicable; and all periods during the compliance determination when the pilot flame or flare flame is absent.

(g) For each maintenance vent opening subject to the requirements of § 60.702a(c), you must keep the applicable records specified in paragraphs (g)(1) through (5) of this section.

(1) You 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 § 60.702a(c). 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 § 60.702a(c)(1)(i), and the lower explosive limit at the time of the vessel opening exceeds 10 percent,

identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, and the lower explosive limit at the time of the vessel opening.

(3) If complying with the requirements of § 60.702a(c)(1)(ii), and either the vessel pressure at the time of the vessel opening exceeds 5 psig or the lower explosive limit at the time of the active purging was initiated exceeds 10 percent, identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, the pressure of the vessel or equipment at the time of discharge to the atmosphere and, if applicable, the lower explosive limit of the vapors in the equipment when active purging was initiated.

(4) If complying with the requirements of § 60.702a(c)(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 inventory procedures specified in paragraph (g)(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 (g)(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 § 60.702a(c)(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 lower explosive limit 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.

(h) If you seek to comply with the requirements of this subpart by complying with the design production capacity provision in § 60.700a(c)(2) you must keep up-to-date, readily accessible records of any change in equipment or process operation that increases the design production capacity of the process unit in which the affected facility is located.

(i) If you seek to comply with the requirements of this subpart by complying with the flow rate cutoff in § 60.700a(c)(3) you must keep up-to-date, readily accessible records to indicate that the vent stream flow rate is less than 0.011 scm/min and of any change in equipment or process operation that increases the operating vent stream flow rate, including a measurement of the new vent stream flow rate.

(j) If you seek to comply with the requirements of this subpart by complying with the low concentration exemption in § 60.700a(c)(7) you must keep up-to-date, readily accessible records of any change in equipment or process operation that increases the concentration of the vent stream of the affected facility.

(k) You must submit to the Administrator semiannual reports of the information specified in paragraphs (k)(1) through (10) of this section. You are exempt from the reporting requirements specified in § 60.7(c). If there are no exceedances, periods, or events specified in paragraphs (k)(1) through (10) of this section that occurred during the reporting period, then you must include a statement in your report that no exceedances, periods, and events specified in paragraphs (k)(1) through (10) of this section occurred during the reporting period. The initial report must be submitted within 6 months after the initial start-up-date. On and after July 15, 2024 or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for 1 year, whichever date is later, you must submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (l) of this section. 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. All semiannual reports must include the following general information: company name, address (including county), and beginning and ending dates of the reporting period.

(1) Exceedances of monitored parameters recorded under paragraph (c) of this section. For each exceedance, the report must include a list of the affected facilities or equipment, the monitored parameter that was exceeded, the start date and time of the exceedance, the duration (in hours) of the exceedance, 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 exceedance (including unknown cause, if applicable), as applicable, and the corrective action taken.

(2) All periods recorded under paragraph (d) of this section when the vent stream is diverted from the control device or recovery device, or has no flow rate, including the information specified in paragraphs (k)(2)(i) through (iii) of this section.

(i) For periods when the flow indicator is not operating, report the identification of the flow indicator and the start date, start time, and duration in hours.

(ii) For each flow event from a relief valve discharge subject to the requirements in § 60.702a(b)(1), the semiannual report must include the identification of the relief valve, the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of TOC in the gas in parts per million by volume and the resulting mass emissions of TOC in pounds that released to the atmosphere.

(iii) For each flow event from a bypass line subject to the requirements in §§ 60.702a(b)(2) and 60.710a(e)(2), the semiannual report must include the identification of the bypass line, the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of TOC in the gas in parts per million by volume and the resulting mass emissions of TOC in pounds that bypass a control device or recovery device.

(3) All periods when a boiler or process heater was not operating (considering the records recorded under paragraph (e) of this section), including the start date, start time, and duration in hours of each period.

(4) For each flare subject to the requirements in § 60.709a, the

semiannual report must include an identification of the flare and the items specified in § 60.709a(l)(2).

(5) For each closed vent system subject to the requirements in § 60.710a, the semiannual report must include an identification of the closed vent system and the items specified in § 60.710a(i).

(6) Any change in equipment or process operation, as recorded under paragraph (h) of this section, that increases the design production capacity above the low capacity exemption level in § 60.700a(c)(2) and the new capacity resulting from the change for the reactor process unit containing the affected facility. These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. Unless the facility qualifies for an exemption under § 60.700a(c), the facility must begin compliance with the requirements set forth in § 60.702a.

(7) Any change in equipment or process operation that increases the operating vent stream flow rate above the low flow exemption level in § 60.700a(c)(3), including a measurement of the new vent stream flow rate, as recorded under paragraph (i) of this section. These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. Unless the facility qualifies for an exemption under § 60.700a(c), the facility must begin compliance with the requirements set forth in § 60.702a.

(8) Any change in equipment or process operation that increases the vent stream concentration above the low concentration exemption level in § 60.700a(c)(7), including a measurement of the new vent stream concentration, as recorded under paragraph (j) of this section. These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. The performance test is subject to the requirements of § 60.8 and must be submitted according to paragraph (b)(1) of this section. Unless the facility qualifies for an exemption under § 60.700a(c), the facility must begin compliance with the requirements set forth in § 60.702a.

(9) Exceedances of the emission standard in table 1 of this subpart as indicated by a 3-hour average of the TOC CEMS and recorded under paragraph (c) of this section. For each exceedance, the report must include a list of the affected facilities or equipment, the start date and time of the exceedance, the duration (in hours) of the exceedance, an estimate of the quantity in pounds of each regulated pollutant emitted over the emission limit, a description of the method used to estimate the emissions, the cause of the exceedance (including unknown cause, if applicable), as applicable, and the corrective action taken.

(10) Periods when the TOC CEMS was inoperative. For each period, the report must include a list of the affected facilities or equipment, the start date and time of the period, the duration (in hours) of the period, the cause of the inoperability (including unknown cause, if applicable), as applicable, and the corrective action taken.

(l) If you are required to submit notifications or reports following the procedure specified in this paragraph (l), you must submit notifications or 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 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 or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (l)(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 (l).

(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. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the SOCMI NSPS 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, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the SOCMI NSPS Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(m) If you are required to electronically submit notifications or reports through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with the electronic submittal requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (m)(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.

(n) If you are required to electronically submit notifications or reports through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with the electronic submittal requirement. To assert a claim of *force majeure,* you must meet the requirements outlined in paragraphs (n)(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.

(o) The requirements of paragraph (k) of this section remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with paragraph (k) of this section, provided that they comply with the requirements established by the State. The EPA will not approve a waiver of electronic reporting to the EPA in delegating enforcement authority. Thus, electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph cannot be used to relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

(p) If you seek to demonstrate compliance with § 60.700a(c)(2), then you must submit to the Administrator an initial report detailing the design production capacity of the process unit.

(q) If you seek to demonstrate compliance with § 60.700a(c)(3), then you must submit to the Administrator an initial report including a flow rate measurement using the test methods specified in § 60.704a.

(r) If you seek to demonstrate compliance with § 60.700a(c)(4), then you must submit to the Administrator a process design description as part of the initial report. This process design description must be retained for the life of the process. No other records or reports would be required unless process changes are made.

(s) If you seek to demonstrate compliance with § 60.700a(c)(7), then you must submit to the Administrator an initial report including a concentration measurement using the test method specified in § 60.704a.

(t) The Administrator will specify appropriate reporting and recordkeeping requirements where the owner or operator of an affected facility complies with the standards specified under § 60.702a other than as provided under § 60.703a.

(u) If you seek to demonstrate compliance with § 60.702a using a control device, then you must maintain on file a schematic diagram of the affected vent streams, collection system(s), fuel systems, control devices, and bypass systems as part of the initial report. This schematic diagram must be retained for the life of the system.

(v) 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.

§ 60.706a What do the terms associated with reconstruction mean for this subpart?

For purposes of this subpart "fixed capital cost of the new components," as used in § 60.15, includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following April 25, 2023. For purposes of this paragraph, "commenced" means that you have undertaken a continuous program of component replacement or that you have entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

§ 60.707a What are the chemicals that I must produce to be affected by subpart RRRa?

Chemical	CAS No.[1]
Acetaldehyde	75–07–0
Acetic acid	64–19–7
Acetic anhydride	108–24–7
Acetone	67–64–1
Acetone cyanohydrin	75–86–5
Acetylene	74–86–2

Chemical	CAS No.[1]
Acrylic acid	79–10–7
Acrylonitrile	107–13–1
Adipic acid	124–04–9
Adiponitrile	111–69–3
Alcohols, C-11 or lower, mixtures.	
Alcohols, C-12 or higher, mixtures.	
Alcohols, C-12 or higher, unmixed.	
Allyl chloride	107–05–1
Amylene	513–35–9
Amylenes, mixed.	
Aniline	62–53–3
Benzene	71–43–2
Benzenesulfonic acid	98–11–3
Benzenesulfonic acid $C_{10\text{-}16}$-alkyl derivatives, sodium salts	68081–81–2
Benzyl chloride	100–44–7
Bisphenol A	80–05–7
Brometone	76–08–4
1,3-Butadiene	106–99–0
Butadiene and butene fractions.	
n-Butane	106–97–8
1,4-Butanediol	110–63–4
Butanes, mixed.	
1-Butene	106–98–9
2-Butene	25167–67–3
Butenes, mixed.	
n-Butyl acetate	123–86–4
Butyl acrylate	141–32–2
n-Butyl alcohol	71–36–3
sec-Butyl alcohol	78–92–2
tert-Butyl alcohol	75–65–0
Butylbenzyl phthalate	85–68–7
tert-Butyl hydroperoxide	75–91–2
2-Butyne-1,4-diol	110–65–6
Butyraldehyde	123–72–8
Butyric anhydride	106–31–0
Caprolactam	105–60–2
Carbon disulfide	75–15–0
Carbon tetrachloride	56–23–5
Chloroacetic acid	79–11–8
Chlorobenzene	108–90–7
Chlorodifluoromethane	75–45–6
Chloroform	67–66–3
p-Chloronitrobenzene	100–00–5
Citric acid	77–92–9
Cumene	98–82–8
Cumene hydroperoxide	80–15–9
Cyanuric chloride	108–77–0
Cyclohexane	110–82–7
Cyclohexane, oxidized	68512–15–2
Cyclohexanol	108–93–0
Cyclohexanone	108–94–1
Cyclohexanone oxime	100–64–1
Cyclohexene	110–83–8
Cyclopropane	75–19–4
Diacetone alcohol	123–42–2
1,4-Dichlorobutene	110–57–6
3,4-Dichloro-1-butene	64037–54–3
Dichlorodifluoromethane	75–71–8
Dichlorodimethylsilane	75–78–5
Dichlorofluoromethane	75–43–4
Diethanolamine	111–42–2
Diethylbenzene	25340–17–4
Diethylene glycol	111–46–6
Di-isodecyl phthalate	26761–40–0
Dimethyl terephthalate	120–61–6
2,4-(and 2,6)-dinitrotoluene	121–14–2 606–20–2
Dioctyl phthalate	117–81–7
Dodecene	25378–22–7
Dodecylbenzene, nonlinear.	
Dodecylbenzenesulfonic acid	27176–87–0
Dodecylbenzenesulfonic acid, sodium salt	25155–30–0
Epichlorohydrin	106–89–8
Ethanol	64–17–5

Chemical	CAS No.[1]
Ethanolamine	141–43–5
Ethyl acetate	141–78–6
Ethyl acrylate	140–88–5
Ethylbenzene	100–41–4
Ethyl chloride	75–00–3
Ethylene	74–85–1
Ethylene dibromide	106–93–4
Ethylene dichloride	107–06–2
Ethylene glycol	107–21–1
Ethylene glycol monobutyl ether	111–76–2
Ethylene glycol monoethyl ether acetate	111–15–9
Ethylene glycol monomethyl ether	109–86–4
Ethylene oxide	75–21–8
2-Ethylhexyl alcohol	104–76–7
(2-Ethylhexyl) amine	104–75–6
6-Ethyl-1,2,3,4-tetrahydro 9,10-anthracenedione	15547–17–8
Formaldehyde	50–00–0
Glycerol	56–81–5
n-Heptane	142–82–5
Heptenes (mixed).	
Hexamethylene diamine	124–09–4
Hexamethylene diamine adipate	3323–53–3
Hexamethylenetetramine	100–97–0
Hexane	110–54–3
Isobutane	75–28–5
Isobutanol	78–83–1
Isobutylene	115–11–7
Isobutyraldehyde	78–84–2
Isopentane	78–78–4
Isoprene	78–79–5
Isopropanol	67–63–0
Ketene	463–51–4
Linear alcohols, ethoxylated, mixed.	
Linear alcohols, ethoxylated, and sulfated, sodium salt, mixed.	
Linear alcohols, sulfated, sodium salt, mixed.	
Linear alkylbenzene	123–01–3
Maleic anhydride	108–31–6
Mesityl oxide	141–79–7
Methanol	67–56–1
Methylamine	74–39–5
ar-Methylbenzenediamine	25376–45–8
Methyl chloride	74–87–3
Methylene chloride	75–09–2
Methyl ethyl ketone	78–93–3
Methyl isobutyl ketone	108–10–1
Methyl methacrylate	80–62–6
1-Methyl-2-pyrrolidone	872–50–4
Methyl tert-butyl ether.	
Naphthalene	91–20–3
Nitrobenzene	98–95–3
1-Nonene	27215–95–8
Nonyl alcohol	143–08–8
Nonylphenol	25154–52–3
Nonylphenol, ethoxylated	9016–45–9
Octene	25377–83–7
Oil-soluble petroleum sulfonate, calcium salt.	
Pentaerythritol	115–77–5
3-Pentenenitrile	4635–87–4
Pentenes, mixed	109–67–1
Perchloroethylene	127–18–4
Phenol	108–95–2
1-Phenylethyl hydroperoxide	3071–32–7
Phenylpropane	103–65–1
Phosgene	75–44–5
Phthalic anhydride	85–44–9
Propane	74–98–6
Propionaldehyde	123–38–6
Propyl alcohol	71–23–8
Propylene	115–07–1
Propylene glycol	57–55–6
Propylene oxide	75–56–9
Sorbitol	50–70–4
Styrene	100–42–5
Terephthalic acid	100–21–0

Chemical	CAS No.[1]
Tetraethyl lead	78–00–2
Tetrahydrofuran	109–99–9
Tetra (methyl-ethyl) lead.	
Tetramethyl lead	75–74–1
Toluene	108–88–3
Toluene-2,4-diamine	95–80–7
Toluene-2,4-(and, 2,6)-diisocyanate (80/20 mixture)	26471–62–5
1,1,1-Trichloroethane	71–55–6
1,1,2-Trichloroethane	79–00–5
Trichloroethylene	79–01–6
Trichlorofluoromethane	75–69–4
1,1,2-Trichloro-1,2,2-trifluoroethane	76–13–1
Triethanolamine	102–71–6
Triethylene glycol	112–27–6
Vinyl acetate	108–05–4
Vinyl chloride	75–01–4
Vinylidene chloride	75–35–4
m-Xylene	108–38–3
o-Xylene	95–47–6
p-Xylene	106–42–3
Xylenes (mixed)	1330–20–7

[1] CAS numbers refer to the Chemical Abstracts Registry numbers assigned to specific chemicals, isomers, or mixtures of chemicals. Some isomers or mixtures that are covered by the standards do not have CAS numbers assigned to them. The standards apply to all of the chemicals listed, whether CAS numbers have been assigned or not.

§ 60.708a [Reserved]

§ 60.709a What are my requirements if I use a flare to comply with this subpart?

(a) If you use a flare to comply with the TOC emission standard specified in table 1 to this subpart, then you must meet the applicable requirements for flares as specified in §§ 63.670 and 63.671 of this chapter, including the provisions in tables 12 and 13 to part 63, subpart CC, of this chapter, 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 an affected facility, as determined on an annual average basis. For purposes of compliance with this paragraph (a), the following terms are defined in § 63.641 of this chapter: 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.

(b) When determining compliance with the pilot flame requirements specified in § 63.670(b) and (g) of this chapter, 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) of this chapter, the requirement effectively applies starting with the 15-minute block that includes a full 15 minutes of the flaring event. You are required to demonstrate compliance with the velocity and NHVcz requirements starting with the block that contains the fifteenth minute of a flaring event. You are 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) of this chapter, you must develop and implement the flare management plan no later than startup for a new flare that commenced construction on or after April 25, 2023.

(e) Instead of complying with § 63.670(o)(2)(iii) of this chapter, 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) following the procedures specified in § 60.705a(l).

(f) Section 63.670(o)(3)(ii) of this chapter and all references to it do not apply. Instead, you must comply with the maximum flare tip velocity operating limit at all times.

(g) Substitute ‘‘affected facility’’ 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 you must meet the following conditions:

(1) You are not required to comply with the flare tip velocity requirements in § 63.670(d) and (k) of this chapter;

(2) The NHVcz for pressure-assisted mulit-point flares is 800 Btu/scf;

(3) You must determine the 15-minute block average NHVvg using only the direct calculation method specified in § 63.670(l)(5)(ii) of this chapter;

(4) Instead of complying with § 63.670(b) and (g) of this chapter, 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 you 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 deviation of the standard. Deviations in different 15-minute blocks from the same event are considered separate deviations. 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 you choose to conduct a cross-light performance demonstration as specified in this paragraph (i)(5), you 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 you conduct 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) You 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 part 63, subpart CC of this chapter.

(7) If a pressure-assisted multi-point flare is operating under the requirements of an approved alternative means of emission limitations, you 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 you choose to determine compositional analysis for net heating value with a continuous process mass spectrometer, then you must comply with the requirements specified in paragraphs (j)(1) through (7) of this section.

(1) You must meet the requirements in § 63.671(e)(2) of this chapter. You may augment the minimum list of calibration gas components found in § 63.671(e)(2) of this chapter 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, 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 NHVvg.

(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 Performance Specification 9 of appendix B of this part, 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 part 63, subpart CC, of this chapter, for the process mass spectrometer. You may use the alternative sampling line temperature allowed under Net Heating Value by Gas Chromatograph in table 13 to part 63, subpart CC, of this chapter.

(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 (j)(7).

Equation 1 to Paragraph (j)(7)

$$CE = \frac{C_m - C_a}{C_a} x\, 100 \text{ (Eq. 1)}$$

Where:

Cm = Average instrument response (ppm)
Ca = Certified cylinder gas value (ppm)

(k) If you use a gas chromatograph or mass spectrometer for compositional analysis for net heating value, then you 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 must be calculated using equation 2 to this paragraph (k).

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 paragraph (q) of § 63.670 of this chapter, you must comply with the reporting requirements specified in paragraphs (l)(1) and (2) of this section.

(1) The notification requirements specified in § 60.705a(a).

(2) The semiannual report specified in § 60.705a(k)(4) 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.

(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) of part 63, subpart CC of this chapter as applicable.

(iv) For flaring events meeting the criteria in § 63.670(o)(3) of this chapter 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) of this chapter 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) of this chapter, you 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) of this chapter 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. You 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 of appendix A–7 of this part, then the record must identify whether the visible emissions observation was performed, the results of each observation, total duration of observed visible emissions, and whether it was a 5-minute or 2-hour observation. 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) of this chapter, 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) of this chapter, 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) of this chapter. 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) of this chapter, as applicable.

(6) All periods during which operating values are outside of the applicable operating limits specified in § 63.670(d) through (f) of this chapter and paragraph (i) of this section when regulated material is being routed to the flare.

(7) All periods during which you do not perform flare monitoring according to the procedures in § 63.670(g) through (j) of this chapter.

(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) of this chapter 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) of this chapter.

(14) For any corrective action analysis for which implementation of corrective actions are required in § 63.670(o)(5) of this chapter, 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) You may elect to comply with the alternative means of emissions limitation requirements specified in § 63.670(r) of this chapter in lieu of the requirements in § 63.670(d) through (f) of this chapter, as applicable. However, instead of complying with § 63.670(r)(3)(iii) of this chapter, you 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: SOCMI NSPS 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 this chapter.

(2) The last sentence of § 63.670(o)(6) of this chapter.

(3) The phrase ''that were not caused by a *force majeure* event'' in § 63.670(o)(7)(ii) of this chapter.

(4) The phrase ''that were not caused by a *force majeure* event'' in § 63.670(o)(7)(iv) of this chapter.

§ 60.710a What are my requirements for closed vent systems?

(a) Except as provided in paragraphs (f) and (g) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) through (3) of this section.

(1) Conduct an initial inspection according to the procedures in paragraph (b) of this section unless the closed vent system is operated and maintained under negative pressure,

(2) Conduct annual inspections according to the procedures in paragraph (b) of this section unless the closed vent system is operated and maintained under negative pressure, and

(3) Conduct annual inspections for visible, audible, or olfactory indications of leaks.

(b) You must inspect each closed vent system according to the procedures specified in paragraphs (b)(1) through (6) of this section.

(1) Inspections must be conducted in accordance with Method 21 of appendix A of this part.

(2)(i) Except as provided in paragraph (b)(2)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 of appendix A of this part, except the instrument response factor criteria in section 3.1.2(a) of Method 21 must be for the average composition of the process fluid not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts which are not organic hazardous air pollutants or volatile organic compounds, the average stream response factor must be calculated on an inert-free basis.

(ii) If no instrument is available at the plant site that will meet the performance criteria specified in paragraph (b)(2)(i) of this section, the instrument readings may be adjusted by multiplying by the average response factor of the process fluid, calculated on an inert-free basis as described in paragraph (b)(2)(i) of this section.

(3) The detection instrument must be calibrated before use on each day of its use by the procedures specified in Method 21 of appendix A of this part.

(4) Calibration gases must be as follows:

(i) Zero air (less than 10 parts per million hydrocarbon in air); and

(ii) Mixtures of methane in air at a concentration less than 2,000 parts per million. A calibration gas other than methane in air may be used if the instrument does not respond to methane or if the instrument does not meet the performance criteria specified in paragraph (b)(2)(i) of this section. In such cases, the calibration gas may be a mixture of one or more of the compounds to be measured in air.

(5) You may elect to adjust or not adjust instrument readings for background. If you elect to not adjust readings for background, all such instrument readings must be compared directly to the applicable leak definition to determine whether there is a leak.

(6) If you elect to adjust instrument readings for background, you must determine the background concentration using Method 21 of appendix A of this part. After monitoring each potential leak interface, subtract the background reading from the maximum concentration indicated by the instrument. The arithmetic difference between the maximum concentration indicated by the instrument and the background level must be compared with 500 parts per million for determining compliance.

(c) Leaks, as indicated by an instrument reading greater than 500 parts per million above background or by visual, audio, or olfactory inspections, must be repaired as soon as practicable, except as provided in paragraph (d) of this section.

(1) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(2) Repair must be completed no later than 15 calendar days after the leak is detected.

(d) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a shutdown, as defined in § 60.2, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment must be complete by the end of the next shutdown.

(e) For each closed vent system that contains bypass lines that could divert a vent stream away from the control device and to the atmosphere, you must comply with the provisions of either paragraph (e)(1) or (2), except as specified in paragraph (e)(3) of this section.

(1) Install, calibrate, maintain, and operate a flow indicator that determines whether vent stream flow is present at least once every 15 minutes. You must keep hourly records of whether the flow indicator 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 vent stream is diverted to the atmosphere or the flow indicator is not operating. The flow indicator must be installed at the entrance to any bypass line; or

(2) Secure the bypass line valve in the closed position with a car-seal or a lock-and-key type configuration. A visual inspection of the seal or closure mechanism must be performed at least once every month to ensure the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(3) 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 (e) of this section.

(f) Any parts of the closed vent system that are designated, as described in paragraph (h)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (a)(1) and (2) of this section if:

(1) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1) and (2) of this section; and

(2) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(g) Any parts of the closed vent system are designated, as described in paragraph (h)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (a)(1) and (2) of this section if:

(1) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) You have a written plan that requires inspection of the equipment at least once every 5 years.

(h) You must record the information specified in paragraphs (h)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each closed vent system that contains bypass lines that could divert a vent stream away from the control device and to the atmosphere, you must keep a record of the information specified in either paragraph (h)(3)(i) or (ii) of this section in addition to the information specified in paragraph (h)(3)(iii) of this section.

(i) Hourly records of whether the flow indicator specified under paragraph (e)(1) of this section 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.

(ii) Where a seal mechanism is used to comply with paragraph (e)(2) of this section, hourly records of flow are not required. In such cases, you must record whether the monthly visual inspection of the seals or closure mechanisms has been done, and you must 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 configuration has been checked out, and records of any car-seal that has broken.

(iii) For each flow event from a bypass line subject to the requirements in paragraph (e) of this section, you 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, you must include an estimate of the volume of gas, the concentration of VOC in the gas and the resulting emissions of VOC that bypassed the control device using process knowledge and engineering estimates.

(4) For each inspection during which a leak is detected, a record of the information specified in paragraphs (h)(4)(i) through (viii) of this section.

(i) The instrument identification numbers; operator name or initials; and identification of the equipment.

(ii) The date the leak was detected and the date of the first attempt to repair the leak.

(iii) Maximum instrument reading measured by the method specified in paragraph (c) of this section after the leak is successfully repaired or determined to be nonrepairable.

(iv) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(v) The name, initials, or other form of identification of the owner or operator (or designee) whose decision it was that repair could not be effected without a shutdown.

(vi) The expected date of successful repair of the leak if a leak is not repaired within 15 calendar days.

(vii) Dates of shutdowns that occur while the equipment is unrepaired.

(viii) The date of successful repair of the leak.

(5) For each inspection conducted in accordance with paragraph (b) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(6) For each inspection conducted in accordance with paragraph (a)(3) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(i) The semiannual report specified in § 60.705a(k)(5) must include the items specified in paragraphs (i)(1) through (3) of this section.

(1) Reports of the times of all periods recorded under paragraph (h)(3)(i) of this section when the vent stream is diverted from the control device through a bypass line. Include the start date, start time, and duration in hours of each period.

(2) Reports of all periods recorded under paragraph (h)(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 of each period.

(3) For bypass lines subject to the requirements in paragraph (e) of this section, the semiannual reports must include the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of VOC in the gas in parts per million by volume and the resulting mass emissions of VOC 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.

TABLE 1 TO SUBPART RRRa OF PART 60—EMISSION LIMITS AND STANDARDS FOR VENT STREAMS

For each. . .	You must. . .
1. Vent stream	a. Reduce emissions of TOC (minus methane and ethane) by 98 weight-percent, or to a TOC (minus methane and ethane) concentration of 20 ppmv on a dry basis corrected to 3 percent oxygen by venting emissions through a closed vent system to any combination of non-flare control devices and/or recovery system and meet the requirements specified in § 60.703a and § 60.710a; *or* b. Reduce emissions of TOC (minus methane and ethane) by venting emissions through a closed vent system to a flare and meet the requirements specified in § 60.709a and § 60.710a.

TABLE 2 TO SUBPART RRRa OF PART 60—MONITORING REQUIREMENTS FOR COMPLYING WITH 98 WEIGHT-PERCENT REDUCTION OF TOTAL ORGANIC COMPOUNDS EMISSIONS OR A LIMIT OF 20 PARTS PER MILLION BY VOLUME

Non-flare control device or recovery device	Parameters to be monitored
1. All control and recovery devices	a. Presence of flow diverted to the atmosphere from the control and recovery device; *or* b. Monthly inspections of sealed valves
2. Absorber	a. Exit temperature of the absorbing liquid; *and* b. Exit specific gravity
3. 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 [a]
4. Catalytic incinerator	Temperature upstream and downstream of the catalyst bed
5. Carbon adsorber, regenerative	a. Total regeneration stream mass or volumetric flow during carbon bed regeneration cycle(s); *and* b. Temperature of the carbon bed after regeneration [and within 15 minutes of completing any cooling cycle(s)]
6. Carbon adsorber, non-regenerative or regenerated offsite	Breakthrough
7. Condenser	Exit (product side) temperature
8. Scrubber for halogenated vent streams	a. pH of scrubber effluent;*and* b. Scrubber liquid and gas flow rates
9. Thermal incinerator	Firebox temperature [a]
10. Control devices other than an incinerator, boiler, process heater, or flare; or recovery devices other than an absorber, condenser, or carbon adsorber.	As specified by the Administrator

[a] Monitor may be installed in the firebox or in the ductwork immediately downstream of the firebox before any substantial heat exchange is encountered.

TABLE 3 TO SUBPART RRRa OF PART 60—OPERATING PARAMETERS, OPERATING PARAMETER LIMITS AND DATA MONITORING, RECORDKEEPING AND COMPLIANCE FREQUENCIES

For the operating parameter applicable to you, as specified in Table 2 . . .	You must establish the following operating parameter limit . . .	And you must monitor, record, and demonstrate continuous compliance using these minimum frequencies . . .		
		Data measurement	Data recording	Data averaging period for compliance
Absorbers				
1. Exit temperature of the absorbing liquid.	Maximum temperature	Continuous	Every 15 minutes	3-hour block average
2. Exit specific gravity	Exit specific gravity range.	Continuous	Every 15 minutes	3-hour block average
Boilers or process heaters (with a design heat input capacity <44MW and vent stream is not introduced with or as the primary fuel)				
3. Firebox temperature.	Minimum firebox temperature.	Continuous	Every 15 minutes	3-hour block average
Catalytic incinerators				
4. Temperature in gas stream immediately before the catalyst bed.	Minimum temperature	Continuous	Every 15 minutes	3-hour block average
5. Temperature difference between the catalyst bed inlet and the catalyst bed outlet.	Minimum temperature difference.	Continuous	Every 15 minutes	3-hour block average
Carbon adsorbers				
6. Total regeneration stream mass flow during carbon bed regeneration cycle(s).	Minimum mass flow during carbon bed regeneration cycle(s).	Continuously during regeneration	Every 15 minutes during regeneration cycle.	Total flow for each regeneration cycle

TABLE 3 TO SUBPART RRRa OF PART 60—OPERATING PARAMETERS, OPERATING PARAMETER LIMITS AND DATA MONITORING, RECORDKEEPING AND COMPLIANCE FREQUENCIES—Continued

For the operating parameter applicable to you, as specified in Table 2 . . .	You must establish the following operating parameter limit . . .	And you must monitor, record, and demonstrate continuous compliance using these minimum frequencies . . .		
		Data measurement	Data recording	Data averaging period for compliance
7. Total regeneration stream volumetric flow during carbon bed regeneration cycle(s).	Minimum volumetric flow during carbon bed regeneration cycle(s).	Continuously during regeneration	Every 15 minutes during regeneration cycle.	Total flow for each regeneration cycle
8. Temperature of the carbon bed after regeneration [and within 15 minutes of completing any cooling cycle(s)].	Maximum temperature of the carbon bed after regeneration.	Continuously during regeneration and for 15 minutes after completing any cooling cycle(s).	Every 15 minutes during regeneration cycle (including any cooling cycle).	Average of regeneration cycle
9. Breakthrough	As defined in § 60.701a.	As required by § 60.703a(a)(6)(iii)(B)	Each monitoring event	N/A
Condensers				
10. Exit (product side) temperature.	Maximum temperature	Continuous	Every 15 minutes	3-hour block average
Scrubbers for halogenated vent streams				
11. pH of scrubber effluent.	Minimum pH	Continuous	Every 15 minutes	3-hour block average
12. Influent liquid flow	Minimum inlet liquid flow.	Continuous	Every 15 minutes	3-hour block average
13. Influent liquid flow rate and gas stream flow rate.	Minimum influent liquid-to-gas ratio.	Continuous	Every 15 minutes	3-hour block average
Thermal incinerators				
14. Firebox temperature.	Minimum firebox temperature.	Continuous	Every 15 minutes	3-hour block average
Control devices other than an incinerator, boiler, process heater, or flare; or recovery devices other than an absorber, condenser, or carbon adsorber				
15. As specified by the Administrator.	As specified by the Administrator.	As specified by the Administrator	As specified by the Administrator.	As specified by the Administrator

TABLE 4 TO SUBPART RRRa OF PART 60—CALIBRATION AND QUALITY CONTROL REQUIREMENTS FOR CONTINUOUS PARAMETER MONITORING SYSTEM (CPMS)

If you monitor this parameter . . .	Your accuracy requirements are . . .	And your calibration requirements are . . .
1. Temperature	a. ±1 percent over the normal range of temperature measured or 2.8 degrees Celsius (5 degrees Fahrenheit), whichever is greater, for non-cryogenic temperature ranges. b. ±2.5 percent over the normal range of temperature measured or 2.8 degrees Celsius (5 degrees Fahrenheit), whichever is greater, for cryogenic temperature ranges.	c. Performance evaluation annually and following any period of more than 24 hours throughout which the temperature exceeded the maximum rated temperature of the sensor, or the data recorder was off scale. d. Visual inspections and checks of CPMS operation every 3 months, unless the CPMS has a redundant temperature sensor. e. Selection of a representative measurement location.

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.

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. The EPA expects these rules will not reduce crude oil supply, fuel production, coal production, natural gas production, or electricity production. The EPA estimates these rules will have minimal impact on the amount of imports or exports of crude oils, condensates, or other organic liquids used in the energy supply industries. Given the minimal impacts on energy supply, distribution, and use as a whole nationally, no significant adverse energy effects are expected to occur. For more information on these estimates of energy effects, please refer to Chapter 5 of the RIA available in the docket.

I. National Technology Transfer and Advancement Act (NTTAA)

This action involves technical standards. The EPA has decided to use EPA Method 18. While the EPA identified ASTM 6420–18 as being potentially applicable, the Agency decided not to use it. The use of this voluntary consensus standard would be impractical because it has a limited list of analytes and is not suitable for analyzing many compounds that are expected to occur in gasoline vapor.

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

For NESHAP subparts R and BBBBBB, 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 percent Hispanic or Latino population, African American, and Other and Multiracial are above the national averages for these demographic groups. The percent of people living below the poverty level and those over 25 without a high school diploma, and people living in linguistic isolation are also higher than the national averages. The EPA believes that this action is likely to reduce existing disproportionate and adverse effects on communities with environmental justice concerns. The EPA estimates that these NESHAP final rules will reduce HAP emissions from gasoline distribution facilities by over 2,200 tpy and VOC emissions by 42,500 tpy.

For NSPS subpart XXa, the EPA believes that it is not practicable to assess whether this action is likely to result in new disproportionate and adverse effects on communities with environmental justice concerns, because the location and number of new, modified, or reconstructed sources is unknown. Because NSPS subpart XXa applies to future new facilities, the locations of such Bulk Gasoline Terminals that will be subject to NSPS subpart XXa are not known. In addition, it is not known which existing Bulk Gasoline Terminals may be modified or reconstructed and subject to NSPS subpart XXa. Thus, we are limited in our ability to estimate the potential EJ impacts of this subpart, but we note that future emission increases associated with construction of any new, modified, or reconstructed sources will be minimized to levels of BSER.

The information supporting this Executive order review is contained in section IV.F. of this action, with additional details in section IV.F. of the proposed rules' preamble (87 FR 35637; June 10, 2022), and in the technical report, *Analysis of Demographic Factors for Populations Living Near Gasoline Distribution Facilities,* available in Docket ID No. EPA–HQ–OAR–2020–0371.

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 a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Parts 60 and 63

Environmental protection, Administrative practice and procedures, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

Michael S. Regan,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, parts 60 and 63 of the Code of Federal Regulations are amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

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

Subpart XX—Standards of Performance for Bulk Gasoline Terminals That Commenced Construction, Modification, or Reconstruction After December 17, 1980, and On or Before June 10, 2022

■ 2. The heading for subpart XX is revised to read as set forth above.

■ 3. Section 60.500 is amended by revising paragraph (b) to read as follows:

§ 60.500 Applicability and designation of affected facility.

* * * * *

(b) Each facility under paragraph (a) of this section, the construction or modification of which is commenced after December 17, 1980, and on or before June 10, 2022, is subject to the provisions of this subpart.

* * * * *

■ 4. Subpart XXa is added to read as follows:

Subpart XXa—Standards of Performance for Bulk Gasoline Terminals that Commenced Construction, Modification, or Reconstruction After June 10, 2022

Sec.

Subpart XXa—Standards of Performance for Bulk Gasoline Terminals that Commenced Construction, Modification, or Reconstruction After June 10, 2022

§ 60.500a Applicability and designation of affected facility.

(a) You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the affected facilities listed in paragraphs (a)(1) and (2) of this section.

(1) Each gasoline loading rack affected facility, which is the total of all the loading racks at a bulk gasoline terminal that deliver liquid product into gasoline cargo tanks including the gasoline loading racks, the vapor collection systems, and the vapor processing system.

(2) Each collection of equipment at a bulk gasoline terminal affected facility, which is the total of all equipment associated with the loading of gasoline at a bulk gasoline terminal including the lines and pumps transferring gasoline from storage vessels, the gasoline loading racks, the vapor collection

systems, and the vapor processing system.

(b) Each affected facility under paragraph (a) of this section for which construction, modification (as defined in § 60.2 and detailed in § 60.14), or reconstruction (as detailed in § 60.15 and paragraph (e) of this section) is commenced after June 10, 2022, is subject to the provisions of this subpart.

(c) All standards including emission limitations shall apply at all times, including periods of startup, shutdown, and malfunction. As provided in § 60.11(f), this paragraph (c) supersedes the exemptions for periods of startup, shutdown, and malfunction in subpart A of this part.

(d) A newly constructed gasoline loading rack affected facility that was subject to the standards in § 60.502a(b) will continue to be subject to the standards in § 60.502a(b) for newly constructed gasoline loading rack affected facilities if they are subsequently modified or reconstructed.

(e) For purposes of this subpart:

(1) The cost of the following frequently replaced components of the gasoline loading rack affected facility shall not be considered in calculating either the ''fixed capital cost of the new components'' or the ''fixed capital cost that would be required to construct a comparable entirely new facility'' under § 60.15: pump seals, loading arm gaskets and swivels, coupler gaskets, overfill sensor couplers and cables, flexible vapor hoses, and grounding cables and connectors.

(2) Under § 60.15, the ''fixed capital cost of the new components'' includes the fixed capital cost of all depreciable components, except components specified in paragraph (e)(1) of this section which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following June 10, 2022. For purposes of this paragraph (e)(2), ''commenced'' means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

§ 60.501a Definitions.

The terms used in this subpart are defined in the Clean Air Act, in § 60.2, or in this section as follows:

3-hour rolling average means the arithmetic mean of the previous thirty-six 5-minute periods of valid operating data collected, as specified, for the monitored parameter. Valid data excludes data collected during periods when the monitoring system is out of control, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. The thirty-six 5-minute periods should be consecutive, but not necessarily continuous if operations or the collection of valid data were intermittent.

Bulk gasoline terminal means 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.

Continuous monitoring system is a comprehensive term that may include, but is not limited to, continuous emission monitoring systems, continuous parameter monitoring systems, or other manual or automatic monitoring that is used for demonstrating compliance on a continuous basis.

Equipment means each valve, pump, pressure relief device, open-ended valve or line, sampling connection system, and flange or other connector in the gasoline liquid transfer and vapor collection systems. This definition also includes the entire vapor processing system except the exhaust port(s) or stack(s).

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.

Gasoline cargo tank means a delivery tank truck or railcar which is loading gasoline or which has loaded gasoline on the immediately previous load.

In gasoline service means that a piece of equipment is used in a system that transfers gasoline or gasoline vapors.

Loading rack means the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill gasoline cargo tanks.

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 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.

Total organic compounds (TOC) means those compounds measured according to the procedures in Method 25, 25A, or 25B of appendix A–7 to this part. The methane content may be excluded from the TOC concentration as described in § 60.503a.

Vapor collection system means any equipment used for containing total organic compounds vapors displaced during the loading of gasoline cargo tanks.

Vapor processing system means all equipment used for recovering or oxidizing total organic compounds vapors displaced from the affected facility.

Vapor recovery system means processing equipment used to absorb and/or condense collected vapors and return the total organic compounds for blending with gasoline or other petroleum products or return to a petroleum refinery or transmix facility for further processing. Vapor recovery systems include but are not limited to carbon adsorption systems or refrigerated condensers.

Vapor-tight gasoline cargo tank means a gasoline cargo tank which has demonstrated within the 12 preceding months that it meets the annual certification test requirements in § 60.503a(f).

§ 60.502a Standard for volatile organic compound (VOC) emissions from bulk gasoline terminals.

(a) Each gasoline loading rack affected facility shall be equipped with a vapor collection system designed and operated to collect the total organic compounds vapors displaced from gasoline cargo tanks during product loading.

(b) For each newly constructed gasoline loading rack affected facility, the facility owner or operator must meet the applicable emission limitations in paragraph (b)(1) or (2) of this section no later than the date on which § 60.8(a) requires a performance test to be completed. A flare cannot be used to comply with the emission limitations in this paragraph (b).

(1) If a thermal oxidation system is used, maintain the emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline cargo tanks at or below 1.0 milligram of total organic compounds per liter of gasoline loaded (mg/L). Continual compliance with this requirement must be demonstrated as specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) Conduct initial and periodic performance tests as specified in § 60.503a(a) through (c) and meet the emission limitation in this paragraph (b)(1).

(ii) Maintain combustion zone temperature of the thermal oxidation system at or above the 3-hour rolling average operating limit established during the performance test when loading liquid product into gasoline cargo tanks. Valid operating data must exclude periods when there is no liquid product being loaded. If previous contents of the cargo tanks are known, you may also exclude periods when liquid product is loaded but no gasoline cargo tanks are being loaded provided that you excluded these periods in the determination of the combustion zone temperature operating limit according to the provisions in § 60.503a(c)(8)(ii).

(2) If a vapor recovery system is used:

(i) Maintain the emissions to the atmosphere from the vapor collection system at or below 550 parts per million by volume (ppmv) of TOC as propane determined on a 3-hour rolling average when the vapor recovery system is operating;

(ii) Operate the vapor recovery system during all periods when the vapor recovery system is capable of processing gasoline vapors, including periods when liquid product is being loaded, during carbon bed regeneration, and when preparing the beds for reuse; and

(iii) Operate the vapor recovery system to minimize air or nitrogen intrusion except as needed for the system to operate as designed for the purpose of removing VOC from the adsorption media or to break vacuum in the system and bring the system back to atmospheric pressure. Consistent with § 60.12, the use of gaseous diluents to achieve compliance with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere is prohibited.

(c) For each modified or reconstructed gasoline loading rack affected facility, the facility owner or operator must meet the applicable emission limitations in paragraphs (c)(1) through (3) of this section no later than the date on which § 60.8(a) requires a performance test to be completed.

(1) If a thermal oxidation system is used, maintain the emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline cargo tanks at or below 10 mg/L. Continual compliance with this requirement must be demonstrated as specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) Conduct initial and periodic performance tests as specified in § 60.503a(a) through (c) and meet the emission limitation in this paragraph (c)(1).

(ii) Maintain combustion zone temperature of the thermal oxidation system at or above the 3-hour rolling average operating limit established during the performance test when loading liquid product into gasoline cargo tanks. Valid operating data must exclude periods when there is no liquid product being loaded. If previous contents of the cargo tanks are known, you may also exclude periods when liquid product is loaded but no gasoline cargo tanks are being loaded provided that you excluded these periods in the determination of the combustion zone temperature operating limit according to the provisions in § 60.503a(c)(8)(ii).

(iii) As an alternative to the combustion zone temperature operating limit, you may elect to use the monitoring provisions as specified in paragraph (c)(3) of this section.

(2) If a vapor recovery system is used:

(i) Maintain the emissions to the atmosphere from the vapor collection system at or below 5,500 ppmv of TOC as propane determined on a 3-hour rolling average when the vapor recovery system is operating;

(ii) Operate the vapor recovery system during all periods when the vapor recovery system is capable of processing gasoline vapors, including periods when liquid product is being loaded, during carbon bed regeneration, and when preparing the beds for reuse; and

(iii) Operate the vapor recovery system to minimize air or nitrogen intrusion except as needed for the system to operate as designed for the purpose of removing VOC from the adsorption media or to break vacuum in the system and bring the system back to atmospheric pressure. Consistent with § 60.12, the use of gaseous diluents to achieve compliance with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere is prohibited.

(3) If a flare is used or if a thermal oxidation system for which these provisions are specified as a monitoring alternative is used, meet all applicable requirements specified in § 63.670(b) through (g) and (i) through (n) of this chapter except as provided in paragraphs (c)(3)(i) through (ix) of this section.

(i) For the purpose of this subpart, ''regulated materials'' refers to ''vapors displaced from gasoline cargo tanks during product loading''. If you do not know the previous contents of the cargo tank, you must assume that cargo tank is a gasoline cargo tank.

(ii) In § 63.670(c) of this chapter for visible emissions:

(A) The phrase ''specify the smokeless design capacity of each flare and'' does not apply.

(B) The phrase ''and the flare vent gas flow rate is less than the smokeless design capacity of the flare'' does not apply.

(C) Substitute ''The owner or operator shall monitor for visible emissions from the flare as specified in § 60.504a(c)(4).'' for the sentence ''The owner or operator shall monitor for visible emissions from the flare as specified in paragraph (h) of this section.''

(iii) The phrase ''and the flare vent gas flow rate is less than the smokeless design capacity of the flare'' in § 63.670(d) of this chapter for flare tip velocity requirements does not apply.

(iv) Substitute ''pilot flame or flare flame'' for each occurrence of ''pilot flame.''

(v) Substitute ''gasoline distribution facility'' for each occurrence of ''petroleum refinery'' or ''refinery.''

(vi) As an alternative to the flow rate monitoring alternatives provided in § 63.670(i) of this chapter, you may elect to determine flare waste gas flow rate by monitoring the cumulative loading rates of all liquid products loaded into cargo tanks for which the displaced vapors are managed by the affected facility's vapor collection system and vapor processing system.

(vii) If using provision in § 63.670(j)(6) of this chapter for flare vent gas composition monitoring, you must comply with those provisions as specified in paragraphs (c)(3)(vii)(A) through (G) of this section.

(A) You must submit a separate written application to the Administrator for an exemption from monitoring, as described in § 63.670(j)(6)(i) of this chapter.

(B) You must determine the minimum ratio of gasoline loaded to total liquid product loaded for which the affected source must operate at or above at all times when liquid product is loaded into cargo tanks for which vapors collected are sent to the flare or, if applicable, thermal oxidation system and include that in the explanation of conditions expected to produce the flare gas with lowest net heating value as required in § 63.670(j)(6)(i)(C) of this chapter. For air assisted flares or thermal oxidation systems, you must also establish a minimum gasoline loading rate (*i.e.,* volume of gasoline loaded in a 15-minute period) for which the affected source must operate at or above at all times and include that in the explanation of conditions that ensure the flare gas net heating value is consistent and representative of the lowest net heating value as required in § 63.670(j)(6)(i)(C).

(C) As required in § 63.670(j)(6)(i)(D) of this chapter, samples must be collected at the conditions identified in § 63.670(j)(6)(i)(C) of this chapter, which includes the applicable conditions specified in paragraph (c)(3)(vii)(B) of this section.

(D) The first change from winter gasoline to summer gasoline or from summer gasoline to winter gasoline, whichever comes first, is considered a change in operating conditions under § 63.670(j)(6)(iii) of this chapter and must be evaluated according to the provisions in § 63.670(j)(6)(iii). If separate net heating values are determined for summer gasoline loading versus winter gasoline loading, you may use the summer net heating value for all subsequent summer gasoline loading operations and the winter net heating value for all subsequent winter gasoline loading operations provided there are no other changes in operations.

(E) You must monitor the volume of gasoline loaded and the total volume of liquid product loaded on a 5-minute block basis and maintain the ratio of gasoline loaded to total liquid product loaded at or above the value determined in paragraph (c)(3)(vii)(B) of this section and, for air assisted flares or thermal oxidation systems, maintain the gasoline loading rate at or above the value determined in paragraph (c)(3)(vii)(B) on a rolling 15-minute period basis, calculated based on liquid product loaded during 3 contiguous 5-minute blocks, considering only those periods when liquid product is loaded into gasoline cargo tanks for any portion of three contiguous 5-minute block periods.

(F) For unassisted or perimeter air assisted flares or thermal oxidation systems, if the net heating value determined in § 63.670(j)(6)(i)(F) of this chapter meets or exceeds 270 British thermal units per standard cubic feet (Btu/scf), compliance with the ratio of gasoline loaded to total liquid product loaded as specified in paragraph (c)(3)(vii)(E) of this section demonstrates compliance with the flare combustion zone net heating value (NHV_{cz}) operating limit in § 63.670(e) of this chapter.

(G) For perimeter air assisted flares or thermal oxidation systems, if the net heating value determined in § 63.670(j)(6)(i)(F) of this chapter meets or exceeds the net heating value dilution parameter (NHV_{dil}) operating limit of 22 British thermal units per square foot (Btu/ft^2) at the flow rate associated with the minimum gasoline loading rate determined in paragraph (c)(3)(vii)(B) of this section at any air assist rate used, compliance with the minimum gasoline loading rate as specified in paragraph (c)(3)(vii)(E) of this section demonstrates compliance with the NHV_{dil} operating limit in § 63.670(f) of this chapter.

(viii) You may elect to establish a minimum supplemental gas addition rate and monitor the supplemental gas addition rate, in addition to the operating limits in paragraph (c)(3)(vii)(E) of this section, to demonstrate compliance with the flare combustion zone operating limit in § 63.670(e) of this chapter and, if applicable, flare dilution operating limit in § 63.670(f) of this chapter, as follows.

(A) Use the minimum flare vent gas net heating value prior to addition of supplemental gas as established in paragraph (c)(3)(vii) of this section.

(B) Determine the maximum flow rate based on the maximum cumulative loading rate for a 15-minute block period considering all loading racks at the affected facility and considering restrictions on maximum loading rates necessary for compliance with the maximum pressure limits for the vapor collection and liquid loading equipment specified in paragraph (h) of this section.

(C) Determine the supplemental gas addition rate needed to yield NHV_{cz} of 270 Btu/scf using equation in § 63.670(m)(1) of this chapter.

(D) For flares (or thermal oxidation systems) with perimeter assist air, determine the supplemental gas addition rate needed to yield NHV_{dil} of 22 Btu/ft^2 using equation in § 63.670(n)(1) of this chapter at the flare vent gas net heating value determined in paragraph (c)(3)(vii) of this section, the flare gas flow rate associated with the minimum gasoline loading rate as determined in paragraph (c)(3)(vii)(B) of this section, and the fixed air assist rate. If the air assist rate is varied based on total liquid product loading rates, you must use the air assist rate used at low flow rates and repeat the calculation using the minimum flow rate associated with each air assist rate setting and select the maximum supplemental gas addition rate across any of the air assist rate settings.

(E) Maintain the supplemental gas addition rate above the greater of the values determined in paragraphs (c)(3)(viii)(C) and, if applicable, (c)(3)(viii)(D) of this section on a 15-minute block period basis when liquid product is loaded into gasoline cargo tanks for at least 15-minutes.

(ix) As an alternative to determining the flare tip velocity rate for each 15-minute block to determine compliance with the flare tip velocity operating limit as specified in § 63.670(k)(2) of this chapter, you may elect to conduct a one-time flare tip velocity operating limit compliance assessment as provided in paragraphs (c)(3)(ix)(A) through (D) of this section. If the flare or loading rack configurations change (*e.g.,* flare tip modified or additional loading racks are added for which vapors are directed to the flare), you must repeat this one-time assessment based on the new configuration.

(A) Determine the unobstructed cross-sectional area of the flare tip, in units of square feet, as specified in § 63.670(k)(1) of this chapter.

(B) Determine the maximum flow rate, in units of cubic feet per second, based on the maximum cumulative loading rate for a 15-minute block period considering all loading racks at the gasoline loading racks affected facility and considering restrictions on maximum loading rates necessary for compliance with the maximum pressure limits for the vapor collection and liquid loading equipment specified in paragraph (h) of this section.

(C) Calculate the maximum flare tip velocity as the maximum flow rate from paragraph (c)(3)(ix)(B) of this section divided by the unobstructed cross-sectional area of the flare tip from paragraph (c)(3)(ix)(A) of this section.

(D) Demonstrate that the maximum flare tip velocity as calculated in paragraph (c)(3)(ix)(C) of this section is less than 60 feet per second.

(d) Each vapor collection system for the gasoline loading rack affected facility shall be designed to prevent any total organic compounds vapors collected at one loading rack from passing to another loading rack.

(e) Loadings of liquid product into gasoline cargo tanks at a gasoline loading rack affected facility shall be limited to vapor-tight gasoline cargo tanks according to the methods in § 60.503a(f) using the following procedures:

(1) The owner or operator shall obtain the vapor tightness annual certification test documentation described in § 60.505a(a)(3) for each gasoline cargo

tank which is to be loaded at the affected facility. If you do not know the previous contents of a cargo tank, you must assume that cargo tank is a gasoline cargo tank.

(2) The owner or operator shall obtain and record the cargo tank identification number of each gasoline cargo tank which is to be loaded at the affected facility.

(3) The owner or operator shall cross-check each cargo tank identification number obtained in paragraph (e)(2) of this section with the file of gasoline cargo tank vapor tightness documentation specified in paragraph (e)(1) of this section prior to loading any liquid product into the gasoline cargo tank.

(f) Loading of liquid product into gasoline cargo tanks at a gasoline loading rack affected facility shall be conducted using submerged filling, as defined in § 60.501a, and only into gasoline cargo tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system. If you do not know the previous contents of a cargo tank, you must assume that cargo tank is a gasoline cargo tank.

(g) Loading of liquid product into gasoline cargo tanks at a gasoline loading rack affected facility shall only be conducted when the terminal's and the cargo tank's vapor collection systems are connected. If you do not know the previous contents of a cargo tank, you must assume that cargo tank is a gasoline cargo tank.

(h) The vapor collection and liquid loading equipment for a gasoline loading rack affected facility shall be designed and operated to prevent gauge pressure in the gasoline cargo tank from exceeding 18 inches of water (460 millimeters (mm) of water) during product loading. This level is not to be exceeded and must be continuously monitored according to the procedures specified in § 60.504a(d).

(i) No pressure-vacuum vent in the gasoline loading rack affected facility's vapor collection system shall begin to open at a system pressure less than 18 inches of water (460 mm of water) or at a vacuum of less than 6.0 inches of water (150 mm of water).

(j) Each owner or operator of a collection of equipment at a bulk gasoline terminal affected facility shall perform leak inspection and repair of all equipment in gasoline service, which includes all equipment in the vapor collection system, the vapor processing system, and each loading rack and loading arm handling gasoline, according to the requirements in paragraphs (j)(1) through (8) of this section. The owner or operator must keep a list, summary description, or diagram(s) showing the location of all equipment in gasoline service at the facility.

(1) Conduct leak detection monitoring of all pumps, valves, and connectors in gasoline service using either of the methods specified in paragraph (j)(1)(i) or (ii) of this section.

(i) Use optical gas imaging (OGI) to quarterly monitor all pumps, valves, and connectors in gasoline service as specified in § 60.503a(e)(2).

(ii) Use Method 21 of appendix A–7 to this part as specified in § 60.503a(e)(1) and paragraphs (j)(1)(ii)(A) through (C) of this section.

(A) All pumps must be monitored quarterly, unless the pump meets one of the requirements in § 60.482–1a(d) or § 60.482–2a(d) through (g). An instrument reading of 10,000 ppm or greater is a leak.

(B) All valves must be monitored quarterly, unless the valve meets one of the requirements in § 60.482–1a(d) or § 60.482–7a(f) through (h). An instrument reading of 10,000 ppm or greater is a leak.

(C) All connectors must be monitored annually, unless the connector meets one of the requirements in § 60.482–1a(d) or § 60.482–11a(e) or (f). An instrument reading of 10,000 ppm or greater is a leak.

(2) During normal duties, record leaks identified by audio, visual, or olfactory methods.

(3) If evidence of a potential leak is found at any time by audio, visual, olfactory, or any other detection method for any equipment (as defined in § 60.501a), a leak is detected.

(4) For pressure relief devices, comply with the requirements in paragraphs (j)(4)(i) through (ii) of this section.

(i) Conduct instrument monitoring of each pressure relief device quarterly and within 5 calendar days after each pressure release to detect leaks by the methods specified in paragraph (j)(1) of this section, except as provided in § 60.482–4a(c).

(ii) If emissions are observed when using OGI, a leak is detected. If Method 21 is used, an instrument reading of 10,000 ppm or greater indicates a leak is detected.

(5) For sampling connection systems, comply with the requirements in § 60.482–5a.

(6) For open-ended valves or lines, comply with the requirements in § 60.482–6a.

(7) When a leak is detected for any equipment, comply with the requirements of paragraphs (j)(7)(i) through (iii) of this section.

(i) A weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on equipment may be removed after it has been repaired.

(ii) An initial attempt at repair shall be made as soon as practicable, but no later than 5 calendar days after the leak is detected. An initial attempt at repair is not required if the leak is detected using OGI and the equipment identified as leaking would require elevating the repair personnel more than 2 meters above a support surface.

(iii) Repair or replacement of leaking equipment shall be completed within 15 calendar days after detection of each leak, except as provided in paragraph (j)(8) of this section.

(A) For leaks identified pursuant to instrument monitoring required under paragraph (j)(1) of this section, the leak is repaired when instrument re-monitoring of the equipment does not detect a leak.

(B) For leaks identified pursuant to paragraph (j)(2) of this section, the leak is repaired when the leak can no longer be identified using audio, visual, or olfactory methods.

(8) Delay of repair of leaking equipment will be allowed according to the provisions in paragraphs (j)(8)(i) though (iv) of this section. The owner or operator shall provide in the semiannual report specified in § 60.505a(c), the reason(s) why the repair was delayed and the date each repair was completed.

(i) Delay of repair of equipment will be allowed for equipment that is isolated from the affected facility and that does not remain in gasoline service.

(ii) Delay of repair for valves and connectors will be allowed if:

(A) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(B) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with § 60.482–10a or the requirements in paragraph (b) or (c) of this section, as applicable.

(iii) Delay of repair will be allowed for a valve, but not later than 3 months after the leak was detected, if valve assembly replacement is necessary, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted.

(iv) Delay of repair for pumps will be allowed if:

(A) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system; and

(B) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(k) You must not allow gasoline to be handled at a bulk gasoline terminal that contains an affected facility listed under § 60.500a(a) 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 and all gasoline storage tank fill-pipes 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.

§ 60.503a Test methods and procedures.

(a) *General performance test and performance evaluation requirements.* (1) In conducting the performance tests or evaluations required by this subpart (or as requested by the Administrator), the owner or operator shall use the test methods and procedures as specified in this section, except as provided in § 60.8(b). The three-run requirement of § 60.8(f) does not apply to this subpart.

(2) Immediately before the performance test, conduct leak detection monitoring following the methods in paragraph (e)(1) of this section to identify leakage of vapor from all equipment, including loading arms, in the gasoline loading rack affected facility while gasoline is being loaded into a gasoline cargo tank to ensure the terminal's vapor collection system equipment is operated with no detectable emissions. The owner or operator shall repair all leaks identified with readings of 500 ppmv (as methane) or greater above background before conducting the performance test and within the timeframe specified in § 60.502a(j)(7).

(b) *Performance test or performance evaluation timing.* (1) For each gasoline loading rack affected facility subject to the mass emission limits in § 60.502a(b)(1) or (c)(1), conduct the initial performance test of the vapor collection and processing systems according to the timing specified in § 60.8(a). For each gasoline loading rack affected facility subject to the emission limits in § 60.502a(b)(2) or (c)(2), conduct the initial performance evaluation of the continuous emissions monitoring system (CEMS) according to the timing specified for performance tests in § 60.8(a).

(2) For each gasoline loading rack affected facility complying with the mass emission limits in § 60.502a(b)(1) or (c)(1), conduct subsequent performance test of the vapor collection and processing system no later than 60 calendar months after the previous performance test.

(3) For each gasoline loading rack affected facility complying with the concentration emission limits in § 60.502a(b)(2) or (c)(2), conduct subsequent performance evaluations of CEMS for the vapor collection and processing system no later than 12 calendar months after the previous performance evaluation.

(c) *Performance test requirements for mass loading emission limit.* The owner or operator of a gasoline loading rack affected facility shall conduct performance tests of the vapor collection and processing system subject to the emission limits in § 60.502a(b)(1) or (c)(1), as specified in paragraphs (c)(1) through (8) of this section.

(1) The performance test shall be 6 hours long during which at least 80,000 gallons (300,000 liters) of gasoline is loaded. If this is not possible, the test may be continued the same day until 80,000 gallons (300,000 liters) of gasoline is loaded. If 80,000 gallons (300,000 liters) cannot be loaded during the first day of testing, the test may be resumed the next day with another 6-hour period. During the second day of testing, the 80,000-gallon (300,000-liter) criterion need not be met. However, as much as possible, testing should be conducted during the 6-hour period in which the highest throughput of gasoline normally occurs.

(2) If the vapor processing system is intermittent in operation and employs an intermediate vapor holder to accumulate total organic compounds vapors collected from gasoline cargo tanks, the performance test shall begin at a reference vapor holder level and shall end at the same reference point. The test shall include at least two startups and shutdowns of the vapor processor. If this does not occur under automatically controlled operations, the system shall be manually controlled.

(3) The emission rate (E) of total organic compounds shall be computed using the following equation:

$$E = K\sum_{i=1}^{n}\left(V_{esi}C_{ei}\right) / \left(L\,10^{6}\right)$$

Equation 1 to paragraph (c)(3)

Where:

E = emission rate of total organic compounds, mg/liter of gasoline loaded.
V_{esi} = volume of air-vapor mixture exhausted at each interval "i", scm.
C_{ei} = concentration of total organic compounds at each interval "i", ppm.
L = total volume of gasoline loaded, liters.
n = number of testing intervals.
i = emission testing interval of 5 minutes.
K = density of calibration gas, 1.83×10^6 for propane, mg/scm.

(4) The performance test shall be conducted in intervals of 5 minutes. For each interval "i", readings from each measurement shall be recorded, and the volume exhausted (V_{esi}) and the corresponding average total organic compounds concentration (C_{ei}) shall be determined. The sampling system response time shall be accounted for when determining the average total organic compounds concentration corresponding to the volume exhausted.

(5) Method 2B of appendix A–1 to this part shall be used to determine the volume (V_{esi}) of air-vapor mixture exhausted at each interval.

(6) Method 25, 25A, or 25B of appendix A–7 to this part shall be used for determining the total organic compounds concentration (C_{ei}) at each interval. Method 25 must not be used if the outlet TOC concentration is less than 50 ppmv. The calibration gas shall be propane. If the owner or operator conducts the performance test using either Method 25A or Method 25B, the methane content in the exhaust vent may be excluded following the procedures in paragraphs (c)(6)(i) through (v) of this section. Alternatively, an instrument that uses gas chromatography with a flame ionization detector may be used according to the procedures in paragraph (c)(6)(vi) of this section.

(i) Measure the methane concentration by Method 18 of appendix A–6 to this part or Method 320 of appendix A to part 63 of this chapter.

(ii) Calibrate the Method 25A or Method 25B analyzer using both propane and methane to develop response factors to both compounds.

(iii) Determine the TOC concentration with the Method 25A or Method 25B analyzer on an as methane basis.

(iv) Subtract the methane measured according to paragraph (c)(6)(i) of this section from the concentration determined in paragraph (c)(6)(iii) of this section.

(v) Convert the concentration difference determined in paragraph (c)(6)(iv) of this section to TOC (minus methane), as propane, by using the response factors determined in paragraph (c)(6)(ii) of this section. Multiply the concentration difference in paragraph (c)(6)(iv) of this section by the ratio of the response factor for propane to the response factor for methane.

(vi) Methane must be separated by the gas chromatograph and measured by the flame ionization detector, followed by a back-flush of the chromatographic column to directly measure TOC concentration minus methane. Use a direct interface and heated sampling line from the sampling point to the gas chromatographic injection valve. All sampling components leading to the analyzer must be heated to greater than 110 °C. Calibrate the instrument with propane. Calibration error and calibration drift must be demonstrated according to Method 25A, and the appropriate procedures in Method 25A must be followed to ensure the calibration error and calibration drift are within Method 25A limits. The TOC concentration minus methane must be recorded at least once every 15 minutes. The performance test report must include the calibration results and the results demonstrating proper separation of methane from the TOC concentration.

(7) To determine the volume (L) of gasoline dispensed during the performance test period at all loading racks whose vapor emissions are controlled by the processing system being tested, terminal records or readings from gasoline dispensing meters at each loading rack shall be used.

(8) Monitor the temperature in the combustion zone using the continuous parameter monitoring system (CPMS) required in § 60.504a(a) and determine the operating limit for the combustion device using the following procedures:

(i) Record the temperature or average temperature for each 5-minute period during the performance test.

(ii) Using only the 5-minute periods in which liquid product is loaded into gasoline cargo tanks, determine the 1-hour average temperature for each hour of the performance test. If you do not know the previous contents of the cargo tank, you must assume liquid product loading is performed in gasoline cargo tanks such that you use all 5-minute periods in which liquid product is loaded into gasoline cargo tanks when determining the 1-hour average temperature for each hour of the performance test.

(iii) Starting at the end of the third hour of the performance test and at the end of each successive hour, calculate the 3-hour rolling average temperature using the 1-hour average values in paragraph (c)(8)(ii) of this section. For a 6-hour test, this would result in four 3-hour averages (averages for hours 1 through 3, 2 through 4, 3 through 5, and 4 through 6).

(iv) Set the operating limit at the lowest 3-hour average temperature determined in paragraph (c)(8)(iii) of this section. New operating limits become effective on the date that the performance test report is submitted to the U.S. Environmental Protection Agency (EPA) Compliance and Emissions Data Reporting Interface (CEDRI), per the requirements of § 60.505a(b).

(d) *Performance evaluation requirements for concentration emission limit.* The owner or operator shall conduct performance evaluations of the CEMS for vapor collection and processing systems subject to the emission limits in § 60.502a(b)(2) or (c)(2) as specified in paragraph (d)(1) or (2) of this section, as applicable.

(1) If the CEMS uses a nondispersive infrared analyzer, the CEMS must be installed, evaluated, and operated according to the requirements of Performance Specification 8 of appendix B to this part. Method 25B in appendix A–7 to this part must be used as the reference method, and the calibration gas must be propane. The owner or operator may request an alternative test method under § 60.8(b) to use a CEMS that excludes the methane content in the exhaust vent.

(2) If the CEMS uses a flame ionization detector, the CEMS must be installed, evaluated, and operated according to the requirements of Performance Specification 8A of appendix B to this part. As part of the performance evaluation, conduct a relative accuracy test audit (RATA) following the procedures in Performance Specification 2, section 8.4, of appendix B to this part; the relative accuracy must meet the criteria of Performance Specification 8, section 13.2, of appendix B to this part. Method 25A in appendix A–7 to this part must be used as the reference method, and the calibration gas must be propane. The owner or operator may exclude the methane content in the exhaust following the procedures in paragraphs (d)(2)(i) through (iv) of this section.

(i) Methane must be separated using a chromatographic column and measured by the flame ionization detector, followed by a back-flush of the chromatographic column to directly measure TOC concentration minus methane.

(ii) The CEMS must be installed, evaluated, and operated according to the requirements of Performance Specification 8A of appendix B to this part, except the target compound is TOC minus methane. As part of the performance evaluation, conduct a RATA following the procedures in Performance Specification 2, section 8.4, of appendix B to this part; the relative accuracy must meet the criteria of Performance Specification 8, section 13.2, of appendix B to this part.

(iii) If the concentration of TOC minus methane in the exhaust stream is greater than 50 ppmv, Method 25 in appendix A–7 to this part must be used as the reference method, and the calibration gas must be propane. If the concentration of TOC minus methane in the exhaust stream is 50 ppmv or less, Method 25A in appendix A–7 to this part must be used as the reference method, and the calibration gas must be propane. If Method 25A is the reference method, the procedures in paragraph (c)(6) of this section may be used to subtract methane from the TOC concentration.

(iv) The TOC concentration minus methane must be recorded at least once every 15 minutes.

(e) *Leak detection monitoring.* Conduct the leak detection monitoring specified in § 60.502a(j)(1) for the collection of equipment at a bulk gasoline terminal affected facility using one of the procedures specified in paragraph (e)(1) or (2) of this section. Conduct the leak detection monitoring specified in paragraph (a)(2) of this section using the procedures specified in paragraph (e)(1) of this section, except that the instrument reading that defines a leak is specified in paragraph (a)(2) for all equipment, including loading arms, in the gasoline loading rack affected facility and the calibration gas in paragraph (e)(1)(ii) must be at a concentration of 500 ppm methane.

(1) Method 21 in appendix A–7 to this part. The instrument reading that defines a leak is 10,000 ppmv (as methane). The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A–7. The calibration

gases in paragraphs (e)(1)(i) and (ii) of this section must be used. The drift assessment specified in paragraph (e)(1)(iii) of this section must be performed at the end of each monitoring day.

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) Methane and air at a concentration of 10,000 ppm methane.

(iii) At the end of each monitoring day, check the instrument using the same calibration gas that was used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 to this part, section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. If multiple scales are used, record the instrument reading for each scale used. Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage. If a calibration drift assessment shows a negative drift of more than 10 percent, then re-monitor all equipment monitored since the last calibration with instrument readings between the leak definition and the leak definition multiplied by (100 minus the percent of negative drift) divided by 100. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the leak definition and below the leak definition multiplied by (100 plus the percent of positive drift) divided by 100 monitored since the last calibration may be re-monitored.

(2) OGI according to all the requirements in appendix K to this part. A leak is defined as any emissions plume imaged by the camera from equipment regulated by this subpart.

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

(1) Method 27 of appendix A–8 to this part. Conduct the test using a time period (t) for the pressure and vacuum tests of 5 minutes. The initial pressure (P_i) for the pressure test shall be 460 mm water (H_2O) (18 in. H_2O), gauge. The initial vacuum (V_i) for the vacuum test shall be 150 mm H_2O (6 in. H_2O), gauge. The maximum allowable pressure and vacuum changes (Δ p, Δ v) are as shown in table 1 to this paragraph (f)(1).

TABLE 1 TO PARAGRAPH (f)(1)—ALLOWABLE GASOLINE CARGO TANK TEST PRESSURE OR VACUUM CHANGE

Gasoline cargo tank or compartment capacity, gallons (liters)	Annual certification-allowable pressure or vacuum change (Δ p, Δ v) in 5 minutes, mm H_2O (in. H_2O)
2,500 or more (9,464 or more)	12.7 (0.50)
1,500 to 2,499 (5,678 to 9,463)	19.1 (0.75)
1,000 to 1,499 (3,785 to 5,677)	25.4 (1.00)
999 or less (3,784 or less)	31.8 (1.25)

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

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

(ii) Relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line. After 5 minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable 5-minute pressure increase is 65 mm H_2O (2.5 in. H_2O).

(3) As an alternative to paragraph (f)(1) of this section, you may use the procedure in § 63.425(i) of this chapter.

§ 60.504a Monitoring requirements.

(a) *Monitoring requirements for thermal oxidation systems complying with the combustion zone temperature operating limit.* Install, operate, and maintain a CPMS for measuring the combustion zone temperature as specified in paragraphs (a)(1) through (5) of this section.

(1) Install the temperature CPMS in the combustion (flame) zone or in the exhaust gas stream as close as practical to the combustion burners in a position that provides a representative temperature of the combustion zone of the thermal oxidation system.

(2) The temperature CPMS must be capable of measuring temperature with an accuracy of ±1 percent over the normal range of temperatures measured.

(3) The temperature CPMS must be capable of recording the temperature at least once every 5 minutes and calculating hourly block averages that include only those 5-minute periods in which liquid product was loaded into gasoline cargo tanks.

(4) 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.

(5) Conduct calibration checks at least annually and 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.

(b) *Monitoring requirements for vapor recovery systems.* Install, calibrate, operate, and maintain a CEMS for measuring the concentration of TOC in the atmospheric vent from the vapor recovery system as specified in paragraphs (b)(1) and (2) of this section. Locate the sampling probe or other interface at a measurement location such that you obtain representative measurements of emissions from the vapor recovery system.

(1) The requirements of Performance Specification 8 of appendix B to this part, or, if the CEMS uses a flame ionization detector, Performance Specification 8A of appendix B to this part, the quality assurance requirements in Procedure 1 of appendix F to this part, and the procedures under § 60.13 must be followed for installation, evaluation, and operation of the CEMS. For CEMS certified using Performance Specification 8A of appendix B, conduct the RATA required under Procedure 1 according to the requirements in § 60.503a(d). As required by § 60.503a(b)(3), conduct annual performance evaluations of each TOC CEMS according to the requirements in § 60.503a(d). Conduct accuracy determinations quarterly and calibration drift tests daily in accordance with Procedure 1 in appendix F.

(2) The span value of the TOC CEMS must be approximately 2 times the applicable emission limit.

(c) *Monitoring requirements for flares and thermal oxidation systems for which flare monitoring alternative is provided.* Install, operate, and maintain CPMS for flares used to comply with the emission limitations in § 60.502a(c)(3), including monitors used for gasoline and total liquid product loading rates, following the requirements specified in § 63.671 of this chapter as specified in paragraphs (c)(1) through (3) of this section and conduct visible emission observations as specified in paragraph (c)(4) of this section.

(1) Substitute ''pilot flame or flare flame'' for each occurrence of ''pilot flame.''

(2) You may elect to determine compositional analysis for net heating value with a continuous process mass spectrometer without the use of a gas

chromatograph. If you choose to determine compositional analysis for net heating value with a continuous process mass spectrometer, then you must comply with the requirements specified in paragraphs (c)(2)(i) through (vii) of this section.

(i) You must meet the requirements in § 63.671(e)(2) of this chapter. You 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.

(ii) Calibration gas cylinders must be certified to an accuracy of 2 percent and traceable to National Institute of Standards and Technology (NIST) standards.

(iii) 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}).

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

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

(vi) You must meet applicable requirements in Performance Specification 9 of appendix B to this part 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 of Performance Specification 9 and performing the periodic calibration requirements listed for gas chromatographs in table 13 to part 63, subpart CC, of this chapter, for the process mass spectrometer. You may use the alternative sampling line temperature allowed under Net Heating Value by Gas Chromatograph in table 13 to part 63, subpart CC.

(vii) 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 the following equation:

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

Equation 1 to paragraph (c)(2)(vii)

Where:

C_m = Average instrument response (ppm).
C_a = Certified cylinder gas value (ppm).

(3) If you use a gas chromatograph or mass spectrometer for compositional analysis for net heating value, then you may choose to use the CE of net heating value (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 NHV must be calculated using the following equation:

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

Equation 2 to paragraph (c)(3)

Where:

$NHV_{measured}$ = Average instrument response (Btu/scf)
NHV_a = Certified cylinder gas value (Btu/scf).

(4) If visible emissions are observed for more than one continuous minute during normal duties, visible emissions observation using Method 22 of appendix A–7 to this part must be conducted for 2 hours or until 5-minutes of visible emissions are observed.

(d) *Pressure CPMS requirements.* The owner or operator shall install, operate, and maintain a CPMS to measure the pressure of the vapor collection system to determine compliance with the standard in § 60.502a(h) as specified in paragraphs (d)(1) through (4) of this section.

(1) Install a pressure CPMS (liquid manometer, magnehelic gauge, or equivalent instrument), capable of measuring up to 500 mm of water gauge pressure with ±2.5 mm of water precision on the terminal's vapor collection system at a pressure tap located as close as possible to the connection with the gasoline cargo tank. If necessary to obtain representative loading pressures, install pressure CPMS for each loading rack.

(2) Check the calibration of the pressure CPMS at least annually. Check the calibration of the pressure CPMS 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.

(3) At least quarterly, visually inspect components of the pressure CPMS for integrity, oxidation and galvanic corrosion, unless the system has a redundant pressure sensor.

(4) The output of the pressure CPMS must be reviewed each operating day to ensure that the pressure readings fluctuate as expected during loading of gasoline cargo tanks to verify the pressure taps are not plugged. Plugged pressure taps must be unplugged or otherwise repaired within 24 hours or prior to the next gasoline cargo tank loading, whichever time period is longer.

(e) *Limited alternative requirements for vapor recovery systems.* If the CEMS used for measuring the concentration of TOC in the atmospheric vent from the vapor recovery system as specified in paragraph (b) of this section requires maintenance such that it is off-line for more than 15 minutes, you may follow the requirements in paragraphs (e)(1) and (2) of this section and monitor product loading quantities and regeneration cycle parameters as an alternative to the monitoring requirement in paragraph (b) for no more than 240 hours in a calendar year.

(1) Determine the quantity of liquid product loaded in gasoline cargo tanks for the past 10 adsorption cycles prior to the CEMS going off-line and select the smallest of these values as your

product loading quantity operating limit.

(2) Determine the vacuum pressure, purge gas quantities, and duration of the vacuum/purge cycles used for the past 10 desorption cycles prior to the CEMS going off-line. You must operate vapor recovery system desorption cycles as specified in paragraphs (e)(2)(i) through (iii) of this section.

(i) The vacuum pressure for each desorption cycle must be at or above the average vacuum pressure from the past 10 desorption cycles. Note: a higher vacuum means a lower absolute pressure.

(ii) Purge gas quantity used for each desorption cycle must be at or above the average quantity of purge gas used from the past 10 desorption cycles.

(iii) Duration of the vacuum/purge cycle for each desorption cycle must be at or above the average duration of the vacuum/purge cycle used from the past 10 desorption cycles.

§ 60.505a Recordkeeping and reporting.

(a) *Recordkeeping requirements.* For each affected facility listed under § 60.500a(a), keep records as specified in paragraphs (a)(1) through (9) of this section, as applicable, for a minimum of five years unless otherwise specified in this section. These recordkeeping requirements supersede the requirements in § 60.7(b).

(1) For each thermal oxidation system used to comply with the emission limitations in § 60.502a(b)(1) or (c)(1) by monitoring the combustion zone temperature as specified in § 60.502a(b)(1)(ii) or (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(b)(2) or (c)(2), maintain records, as applicable, of:

(i) The applicable operating or emission limit for the continuous monitoring system (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 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), 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) 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 (a)(1)(ii) of this section.

(vi) For TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) 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 § 60.502a(c)(3) and for each thermal oxidation system using the flare monitoring alternative as provided in § 60.502a(c)(1)(iii), 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) of this chapter 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 was 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 (a)(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 this part, 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 this part 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) of this chapter 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 flare vent gas or the thermal oxidation system vent gas and, if applicable, total steam, perimeter assist air, and premix assist air specified to be monitored under § 63.670(i) of this chapter, 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 flare vent gas, thermal oxidation system 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), the required minimum 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 flare vent gas compositions or thermal oxidation system vent gas specified to be monitored under § 63.670(j) of this chapter. Retain records of individual component concentrations from each compositional analyses for a minimum of 2 years. If an 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) of this chapter as specified in § 60.502a(c)(3)(vii), retain records of the required minimum ratio of gasoline loaded to total liquid product loaded and the actual ratio on a 5-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 5-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) of this chapter, 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) of this chapter or in § 60.502a(c)(3)(vii) and (viii) 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), 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), 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 (a)(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) The gasoline cargo tank vapor tightness documentation required under § 60.502a(e)(1) for each gasoline cargo tank loading at the affected facility shall be kept on file at the terminal in either a hardcopy or electronic form available for inspection. The documentation shall include, at a minimum, the following information:

(i) Test title: Annual Certification Test—EPA Method 27 or Railcar Bubble Leak Test Procedure.

(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 § 60.502a(e)(1) 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 § 60.501a, 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.

(6) A record [list, summary description, or diagram(s) showing the location] of all equipment in gasoline service at the collection of equipment at a bulk gasoline terminal affected facility and at the loading rack affected facility. A record of each leak inspection and leak identified under §§ 60.503a(a)(2) and 60.502a(j) as specified in paragraphs (a)(6)(i) through (iv) of this section:

(i) For each leak inspection, keep the following records:

(A) An indication if the leak inspection was conducted under § 60.502a(j) or § 60.503a(a)(2).

(B) Leak determination method used for the leak inspection.

(ii) For leak inspections conducted with Method 21 of appendix A–7 to this part, 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.

(iii) For leak inspections conducted with OGI, keep the records specified in section 12 of appendix K to this part.

(iv) For each leak 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, the 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 this part, or OGI).

(C) The dates 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 this part is used to confirm the repair, the maximum instrument reading measured by Method 21 of appendix A–7. 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 this part 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.

(7) Records of each performance test or performance evaluation conducted on the affected facility and each notification and report submitted to the Administrator. 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).

(8) 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.

(9) Any records required to be maintained by this subpart that are submitted electronically via the EPA's Compliance and Emissions 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.

(b) *Reporting requirements for performance tests and evaluations.* 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 following the procedures specified in paragraph (e) of this section. As required by § 60.8(f)(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. 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 or performance evaluation must be included as an attachment in the ERT or an alternate electronic file.

(c) *Reporting requirements for semiannual report.* You must submit to the Administrator semiannual reports with the applicable information in paragraphs (c)(1) through (7) of this section by the dates specified in paragraph (d) of this section following the procedure specified in paragraph (e) of this section. For this subpart, the semiannual reports supersede the excess emissions and monitoring systems performance report and/or summary report form required under § 60.7. Beginning on July 8, 2024, 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, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (e). 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.

(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) 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.

(vi) 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 (c)(1)(vi).

(2) For each thermal oxidation system used to comply with the emission limitations in § 60.502a(b)(1) or (c)(1) by monitoring the combustion zone temperature as specified in § 60.502a(b)(1)(ii) or (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(b)(2) or (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) 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 was 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) 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) 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). 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). 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). 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). Enter 0 if no deviations of this type.

(3) For each flare used to comply with the emission limitations in § 60.502a(c)(3) 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) of this chapter were not met. You must identify the specific operating limit that was not met. Additionally, report the information in paragraphs (c)(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) alone or in combination with the supplemental gas flow rate monitoring alternative in § 60.502a(c)(3)(viii), 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), 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 (c)(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) of this chapter 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 (c)(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) 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 § 60.501a, 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) Type of deviation (*e.g.,* not submerged filling, incompatible equipment, or not properly connected).

(iii) Cargo tank identification number.

(6) Report the following information for each leak inspection required under §§ 60.502a(j)(1) and 60.503a(a)(2) and each leak identified under § 60.502a(j)(2).

(i) For each leak detected during a leak inspection required under §§ 60.502a(j)(1) and 60.503a(a)(2), report:

(A) The date of inspection.

(B) The leak determination method (OGI or Method 21 of appendix A–7 to this part).

(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 type of equipment placed on the delay of repair, as specified in § 60.502a(j)(8).

(ii) For leaks identified under § 60.502a(j)(2), 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).

(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 of appendix A–7 to this part, or audio, visual, or olfactory).

(D) The reason(s) why the repair was not feasible within 15 calendar days.

(E) If applicable, the date repair was completed.

(7) 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 limits, or work practice standards during the reporting period. If there were no periods during which a CMS (including a CEMS or CPMS) was inoperable or out-of-control, then provide a statement that there were no periods during which a CMS was inoperable or out-of-control during the reporting period.

(d) *Timeframe for semiannual report submissions.* (1) The first semiannual report will cover the date starting with the date the source first becomes an affected facility subject to this subpart and ending with the last day of the month five months later. For example, if the source becomes an affected facility on April 15, the first semiannual report would cover the period from April 15 to September 30. The first semiannual report must be submitted on or before the last day of the month two months after the last date covered by the semiannual report. In this example, the first semiannual report would be due November 30.

(2) Subsequent semiannual reports will cover subsequent 6 calendar month periods with each report due on or before the last day of the month two months after the last date covered by the semiannual report.

(e) *Requirements for electronically submitting reports.* For reports required to be submitted following the procedures specified in this paragraph (e), you must submit 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). 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 in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (e)(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 are 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 (e).

(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. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Gasoline Distribution 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, Mail Drop: C404–02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group, and all other files should also be flagged to the attention of the Gasoline Distribution Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(f) *Claims of EPA system outage.* 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 (f)(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.

(g) *Claims of force majeure.* 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 (g)(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.

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:

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2002–0049; FRL–8150–01–OAR]

RIN 2060–AU96

New Source Performance Standards Review for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing amendments to the new source performance standards (NSPS) for electric arc furnaces (EAF) and argon-oxygen decarburization (AOD) vessels in the steel industry pursuant to the review required by the Clean Air Act.

DATES:

Effective date: This final rule is effective August 25, 2023. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of August 25, 2023.

Compliance dates: Affected sources that commence construction, reconstruction, or modification after May16, 2022, must comply with all requirements of 40 CFR part 60, subpart AAb no later than August 25, 2023 or upon startup, whichever is later. The date for complying with the changes in the current rules, 40 CFR part 60, subparts AA and AAa is February 21, 2024 publication of the final rule. The date for complying with the ERT submission requirements is February 21, 2024.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2002–0049. 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 will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Donna Lee Jones, Sector Policies and Programs Division (D243–02), P.O. Box 12055, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5251; and email address: *Jones.DonnaLee@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:

A/C air-to-cloth
ANSI American National Standards Institute
AOD argon-oxygen decarburization
ASME American Society of Mechanical Engineers
BACT best available control technology
BID background information document
BLDS bag leak detection systems
BPT benefits per ton
BSER best system of emissions reduction
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
CO carbon monoxide
COMS continuous opacity monitoring systems
DCOT digital camera opacity technique
DEC direct shell evacuation control
EAF electric arc furnace
EIA economic impact assessment
EJ environmental justice
E.O. executive order
EPA Environmental Protection Agency
ERT electronic reporting tool
FR Federal Register
FRED Federal Reserve Economic Data
GASP Group Against Smog and Pollution
gr grains
gr/dscf grans per dry standard cubic feet
HAP hazardous air pollutants
ICR information collection request
II&S integrated iron and steel industry
ISA Integrated Science Assessment for Particulate Matter
LAER Lowest Achievable Emission Rate
lb pounds
lb/ton pounds per ton
mg/dscm milligrams per dry standard cubic meters
NAICS North American Industry Classification System
NAPCTAC National Air Pollution Control Technical Advisory Committee
NO_X nitrogen oxides
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement
OAQPS Office of Air Quality Planning and Standards
OMB Office of Management and Budget
PDF portable document format
PM particulate matter
$PM_{2.5}$ particulate matter less than 2.5 micrometers
PRA Paperwork Reduction Act
PS performance specification
RACT reasonably available control technology
RFA Regulatory Flexibility Act
RIN regulatory information number
SMA Steel Manufacturers Association
SSM startup, shutdown, and malfunction
tpy tons per year
UMRA Unfunded Mandates Reform Act of 1995
U.S. United States
U.S.C. United States Code
VCS voluntary consensus standard
VE visible emissions

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

I. General Information

A. Does this action apply to me?

The source category that is the subject of this final action is composed of steel manufacturing facilities that operate electric arc furnaces (EAF) and argon-oxygen decarburization (AOD) vessels regulated under CAA section 111 New Source Performance Standards (NSPS). The 2022 North American Industry Classification System (NAICS) code for the source category is 331110 for ''Iron and Steel Mills and Ferroalloy Manufacturing'' processes. The NAICS code serves as a guide for readers outlining the type of entities that this final action is likely to affect. The NSPS codified in 40 CFR part 60, subpart AAb are directly applicable to affected facilities that begin construction, reconstruction, or modification after May 16, 2022. Final amendments to 40 CFR part 60, subpart AA are applicable to affected EAF and AOD facilities that begin construction, reconstruction, or modification after October 21, 1974, and on or before August 17, 1983. Final amendments to 40 CFR part 60, subpart AAa are applicable to affected EAF and AOD vessels facilities that begin construction, reconstruction, or modification after August 17, 1983, and on or before May 16, 2022. Federal, state, local and Tribal government entities would not be affected by this action. If you have any questions regarding the applicability of this action to a particular entity, you should carefully examine the applicability criteria found in 40 CFR part 60, subparts AA, AAa, and AAb, and consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section of this preamble, your state air pollution control agency with delegated authority for NSPS, or your EPA Regional Office.

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 final action is available on the internet at *https://www.epa.gov/stationary-sources-air-pollution/electric-arc-furnaces-eafs-and-argon-oxygen-decarburization.* 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 Review

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 by October 24, 2023. 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 ''[o]nly 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 convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA 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 to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. Environmental Protection Agency, Room 3000, WJC West 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. Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

II. Background

A. What is the statutory authority for this final action?

The EPA's authority for this final rule is CAA section 111, which governs the establishment of standards of performance for stationary sources. Section 111(b)(1)(A) of the CAA requires the EPA Administrator to list categories of stationary sources that in the Administrator's judgment cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for new (and modified or reconstructed) sources in each source category pursuant to CAA section 111(b)(1)(B). These standards are referred to as NSPS. The EPA has the authority to define the scope of the source categories, determine the pollutants for which standards should be developed, set the emission level of the standards, and distinguish among classes, types, and sizes within categories in establishing the standards.

CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years review and, if appropriate, revise'' NSPS. However, the Administrator need not review any such standard if the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. When conducting a review of an existing performance standard, the EPA has the discretion and authority to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to reflect ''the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' The term ''standard of performance'' in CAA section 111(a)(1) makes clear that the EPA is to determine both the best system of emission reduction (BSER) for the regulated sources in the source category and the degree of emission limitation achievable through application of the BSER. The EPA must then, under CAA section

111(b)(1)(B), promulgate standards of performance for new sources that reflect that level of stringency. CAA section 111(b)(5) generally precludes the EPA from prescribing a particular technological system that must be used to comply with a standard of performance. Rather, sources can select any measure or combination of measures that will achieve the standard. CAA section 111(h)(1) authorizes the Administrator to promulgate ''a design, equipment, work practice, or operational standard, or combination thereof'' if in his or her judgment, ''it is not feasible to prescribe or enforce a standard of performance.'' CAA section 111(h)(2) provides the circumstances under which prescribing or enforcing a standard of performance is ''not feasible,'' such as, when the pollutant cannot be emitted through a conveyance designed to emit or capture the pollutant, or when there is no practicable measurement methodology for the particular class of sources.

Pursuant to the definition of new source in CAA section 111(a)(2), standards of performance apply to facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Under CAA section 111(a)(4), ''modification'' means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. Changes to an existing facility that do not result in an increase in emissions are not considered modifications. Under the provisions in 40 CFR 60.15, reconstruction means the replacement of components of an existing facility such that: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility; and (2) it is technologically and economically feasible to meet the applicable standards. Pursuant to CAA section 111(b)(1)(B), the standards of performance or revisions thereof shall become effective upon promulgation.

B. How does the EPA perform the NSPS review?

As noted in section II. A of this preamble, CAA section 111 requires the EPA to, at least every 8 years review and, if appropriate, revise the standards of performance applicable to new, modified, and reconstructed sources. If the EPA revises the standards of performance, they must reflect the degree of emission limitation achievable through the application of the BSER considering the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements. CAA section 111(a)(1).

In reviewing an NSPS to determine whether it is ''appropriate'' to revise the standards of performance, the EPA evaluates the statutory factors, which may include consideration of the following information:

• Expected growth for the source category, including how many new facilities, reconstructions, and modifications may trigger NSPS in the future.

• Pollution control measures, including advances in control technologies, process operations, design or efficiency improvements, or other systems of emission reduction, that are ''adequately demonstrated'' in the regulated industry.

• Available information from the implementation and enforcement of current requirements indicates that emission limitations and percent reductions beyond those required by the current standards are achieved in practice.

• Costs (including capital and annual costs) associated with implementation of the available pollution control measures.

• The amount of emission reductions achievable through application of such pollution control measures.

• Any nonair quality health and environmental impact and energy requirements associated with those control measures.

In evaluating whether the cost of a particular system of emission reduction is reasonable, the EPA considers various costs associated with the particular air pollution control measure or a level of control, including capital costs and operating costs, and the emission reductions that the control measure or particular level of control can achieve. The Agency considers these costs in the context of the industry's overall capital expenditures and revenues. The Agency also considers cost-effectiveness analysis as a useful metric, and a means of evaluating whether a given control achieves emission reduction at a reasonable cost. A cost-effectiveness analysis allows comparisons of relative costs and outcomes (effects) of 2 or more options. In general, cost effectiveness is a measure of the outcomes produced by resources spent. In the context of air pollution control options, cost effectiveness typically refers to the annualized cost of implementing an air pollution control option divided by the amount of pollutant reductions realized annually.

After the EPA evaluates the statutory factors, the EPA compares the various systems of emission reductions and determines which system is ''best,'' and therefore represents the BSER. The EPA then establishes a standard of performance that reflects the degree of emission limitation achievable through the implementation of the BSER. In doing this analysis, the EPA can determine whether subcategorization is appropriate based on classes, types, and sizes of sources, and may identify a different BSER and establish different performance standards for each subcategory. The result of the analysis and BSER determination leads to standards of performance that apply to facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Because the NSPS reflect the best system of emission reduction under conditions of proper operation and maintenance, in doing its review, the EPA also evaluates and determines the proper testing, monitoring, recordkeeping and reporting requirements needed to ensure compliance with the emission standards.

C. What is the source category regulated in this final action?

The EPA first promulgated NSPS under CAA section 111 for EAF at steel plants source category on September 23, 1975 (40 FR 43850). These standards of performance are codified in 40 CFR part 60, subpart AA and are applicable to sources that commence construction, modification, or reconstruction after October 21, 1974, and on or before August 17, 1983. These standards of performance regulate emissions of particulate matter (PM) from EAF capture systems and control devices with a PM concentration limit of 12 milligrams per dry standard cubic meter (mg/dscm) [0.0052 grains per dry standard cubic feet (gr/dscf)] and set opacity limits for using capture technology controlling EAF melt shop emissions, which include, but are not limited to, emissions via roof vents, doors, and cracks in walls of 6 percent opacity, with 20 percent and 40 percent opacity allowed during charging and tapping, respectively; control device exhaust at 3 percent opacity due to proper operation of control devices; and dust handling procedures due to proper handling of captured PM at 10 percent opacity.

In 1984, the NSPS rule, 40 CFR part 60, subpart AA (for EAF constructed after October 21, 1974, and on or before August 17, 1983) was reviewed and revised as part of NSPS statutory review (49 FR 43838; October 31, 1984). The 1984 action amended 40 CFR part 60, subpart AA to include AOD and raise the melt shop opacity from 0 percent to 6 percent opacity, keeping the exceptions for charging (20 percent opacity) and tapping (40 percent opacity). The 1984 action also codified a new NSPS subpart, 40 CFR part 60, subpart AAa, to regulate EAF and AOD vessels that commenced construction after August 17, 1983 (49 FR 43843). The NSPS codified at 40 CFR part 60, subpart AAa set requirements for melt shop opacity at 6 percent with no exceptions. Finally, the 1984 action promulgated requirements to include EPA Method 5D (Appendix A to 40 CFR part 60) for the determination of PM emissions from positive-pressure fabric filters, which are common control devices for EAF and AOD vessels for both 40 CFR part 60, subparts AA and AAa.

On February 14, 1989, 40 CFR part 60, subparts AA and AAa (and Appendix A to 40 CFR part 60) were amended to consolidate the EPA test methods and delete repetitions of methods already referenced (54 FR 6672). Then, on May 17, 1989, minor clarifications and corrections were made to the February 1989 revisions (54 FR 21344). On March 2, 1999, as a result of recommendations made by the EPA's sector policy established in 1994,[1] called the ''Common Sense Initiative,'' 40 CFR part 60, subparts AA and AAa were amended to add an option to monitor furnace static pressure instead of melt shop opacity and to monitor baghouse (fabric filter) fan amperage instead of baghouse flowrate (64 FR 10109). On October 17, 2000, amendments were made to 40 CFR part 60, subparts AA and AAa to promulgate Performance Specification (PS) 15 for certifying continuous emission monitoring systems (CEMS) with Fourier transform infrared spectroscopy (FTIR); to reformat various methods as per recommendations by the Environmental Monitoring Management Council; and to make miscellaneous clarifications and technical and editorial corrections (65 FR 61758). On February 22, 2005, 40 CFR part 60, subparts AA and AAa were amended in response to a petition by the American Iron and Steel Institute, Steel Manufacturers Association (SMA), and Specialty Steel Industry of North America to add bag leak detection systems (BLDS) as an alternative monitoring method to the continuous opacity monitoring systems currently cited in the rules (70 FR 8523).

An EAF is a metallurgical furnace used to produce carbon and alloy steels. The input material to an EAF is typically almost 100 percent scrap steel. Cylindrical, refractory-lined EAF are equipped with carbon electrodes to be raised or lowered through the furnace roof. With electrodes retracted, the furnace roof can be rotated to permit charging scrap steel into the EAF by overhead crane. Alloying agents and fluxing materials usually are added through doors on the side of the furnace. Electric current is passed between the electrodes and through the scrap, producing an arc and generating enough heat to melt the scrap steel charge. After the melting and refining periods, impurities (in the form of slag[2]) and the refined steel are poured from the furnace, in a process called ''tapping.'' If AOD vessels are present, they follow the EAF in the production sequence and are used to oxidize carbon, silicon, and impurities, such as sulfur. For these reasons, the AOD vessels reduce additions of alloying material compared to an EAF alone. Use of AOD vessels also reduce EAF heat times, improve quality control, and increase daily steel production. AOD vessels are primarily used in stainless steel making.

The production of steel in an EAF is a batch process. Cycles, also called heats, range from about 1.5 to 5 hours to produce carbon steel and from 5 to 10 hours to produce alloy steel. Scrap steel is charged to begin a cycle, with alloying agents and slag forming materials added later in the process for refining purposes. The stages of each cycle normally include charging, melting, refining (which also usually includes oxygen blowing), and tapping, all of which generate PM emissions.

Air emission control techniques typically involve an air emission capture system and a gas cleaning system. The air emission capture systems used in the EAF industry include direct shell evacuation control (DEC) systems, side draft hoods, combination hoods, canopy hoods, scavenger ducts, and furnace enclosures. The DEC system consists of ductwork attached to a separate opening, or ''fourth hole,'' in the furnace roof (top) that draws emissions from the furnace to a gas cleaner and which works only when the furnace is up-right and the roof is in place. Side draft hoods collect furnace exhaust gases from around the electrode holes and work doors after the gases leave the furnace. Combination hoods incorporate elements from the side draft and direct shell evacuation systems. Canopy hoods and scavenger ducts are used to address charging and tapping emissions. Baghouses, also called fabric filters, are typically used as gas cleaning systems (*i.e.,* emissions control devices).

There are approximately 88 EAF in the United States (U.S.), with most (>95 percent) EAF subject to one of the EAF NSPS subparts. Thirty-one states have one or more EAF facilities, with most of the EAF facilities east of the Mississippi River. Pennsylvania (15), Ohio (10), Alabama (7), and Indiana (7) have the most EAF facilities per state (approximate number of EAF facilities in each state).

The EPA proposed amendments to the NSPS subparts AA and AAa, and a new subpart AAb, based on the current review on May 16, 2022 (87 FR 29710). We received 11 comments from industry, environmental groups, state environmental agencies, and others during the comment period. A summary of the more significant comments we timely received regarding the proposed rule and our responses are provided in this preamble. A summary of all other public comments on the proposal and the EPA's responses to those comments is available in the document *Summary of Public Comments and Responses for Standards of Performance for Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974, and On or Before August 17, 1983; and Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels, Docket ID No. EPA–HQ–OAR–2002–0049* located in the docket for this rule. In this action, the EPA is finalizing decisions and revisions pursuant to CAA section 111(b)(1)(B) review for Steel Plants: Electric Arc Furnaces (EAF) and Argon-Oxygen Decarburization Vessels NSPS (40 CFR part 60, subpart AAa) after our considerations of all the comments received.

D. What outreach and engagement did the EPA conduct?

As part of this rulemaking, and pursuant to multiple Executive Orders addressing environmental justice, the EPA engaged and consulted with the public, including populations of overburdened communities and low-income populations, through interactions, such as a letter sent on

[1] See *Analysis and Evaluation of the EPA Common Sense Initiative.* Prepared by: Kerr Greiner, Andersen, and April, Inc. Funded by the U.S. Environmental Protection Agency under PO No. No. 9W–0753–NTSA. 1999. Available at *https://NEPIS.epa.gov.*

[2] Slag is the molten metal oxides and other impurities that float to the surface of the molten steel product.

May 17, 2022, to 40 leaders of Tribal nations (see Docket ID No. EPA–HQ–OAR–2002–0049). The EPA received comments from the following environmental groups during the comment period: Group Against Smog and Pollution (GASP), Fairfield Environmental Justice Action Coalition (FEJA), Sierra Club, California Communities Against Toxics, and Greater Birmingham Alliance to Stop Pollution, et al. These opportunities gave the EPA a chance to hear from the public, especially communities potentially impacted by this final action.

Some of the key issues raised by environmental justice stakeholders included a specific area of the country where there are PM problems and where there are 2 EAF facilities; and regulating other pollutants, such as sulfur dioxide (SO_2) and greenhouse gases (GHG). Section V of the preamble provides a description of how the Agency considered these comments in the context of regulatory development.

III. What changes did we propose for the Steel Plants: Electric Arc Furnaces (EAF) and Argon-Oxygen Decarburization Vessels NSPS?

On May 16, 2022, the EPA proposed the results of the review of the EAF and AOD source category standards of performance to determine if revisions were warranted pursuant to CAA section 111(b)(1)(B).

Pursuant to this review, we proposed to revise the NSPS for EAF and AOD vessels. We also proposed several clarifications and corrections to existing NSPS rules (40 CFR part 60, subparts AA and AAa). These proposed actions are discussed below in sections III.A and III.B. We also proposed: periodic compliance testing at least once every 5 years; results of the review of opacity from control device exhaust and from dust handling systems to keep same BSER and limits as in 40 CFR part 6, subpart AAa of 3 percent and 10 percent, respectively; that the emission limits would apply at all times; and electronic reporting.

A. Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed, Reconstructed, or Modified After May 16, 2022

1. Analyses To Determine BSER for Melt Shop Opacity and PM Emissions From Control Devices

The EPA proposed to determine that the use of a baghouse with a fabric filter is the BSER for EAF and AOD vessels. The EPA proposed that a limit of at 0.16 pounds (lb) PM emitted per ton steel produced (lb/ton) reflects the degree of emission limitation achievable through application of the BSER. The EPA also proposed to determine using a partial roof canopy to control visible fugitive emissions (VE) from EAF and AOD in the melt shop is BSER. The EPA proposed that a limit of 0 percent opacity during all phases of EAF operation reflects the degree of emission limitation achievable through application of the BSER.

The BSER and proposed standards of performance for PM emissions from capture systems and fabric filters, and for capture of emissions from melt shops was developed from an analysis of EAF PM test reports from 2005 through 2017 obtained by the EPA. The PM data contained in these reports reflected 33 facilities, 46 EAF, 5 AOD, and 54 baghouses in 154 emission and opacity tests (hereafter referred to as the ''EAF dataset''). The EAF dataset showed a substantial improvement in EAF, AOD, and baghouse performance beyond the current NSPS PM standards (40 CFR part 60, subparts AA, AAa) for control devices as well as for melt shop opacity. The costs of control, emissions reductions, and other factors were used in the determination of BSER, as explained in next sections.

a. BSER for Melt Shop Opacity

From the EAF dataset described earlier in this preamble, the EPA identified 15 EAF facilities, approximately half of the EAF dataset, that reported 0 percent melt shop opacity. To determine BSER and its costs to reduce melt shop opacity at EAF facilities from 6 percent to 0 percent opacity, the costs for an addition of a partition roof canopy (above the crane rails) were estimated for the proposal. Canopy hoods are a common method of controlling fugitive EAF emissions. In the proposal cost analysis, we estimated that the annual costs would be $800,000 ($2020 [3]) for a medium-sized steelmaking EAF with installation of a partition roof canopy (above the crane rails). With an estimated PM reduction of 730 tpy to achieve 0 percent melt shop opacity down from the current 6 percent opacity (in 40 CFR part 60, subparts AA, AAa), the cost effectiveness in $2020 was estimated to be $1,100 per ton PM removed ($2020). Similar results were obtained for both small and large EAF.

[3] The cost analyses for the 2022 proposal used a 3.25 percent interest rate. Federal Reserve Economic Data (FRED). Bank Prime Loan Rate Changes: Historical Dates of Changes and Rates. Available at: *https://fred.stlouisfed.org/series/PRIME.* Accessed 11/6/2020.

Based on the BSER analysis as explained at proposal, the EPA proposed that BSER for melt shop is a partition roof canopy (above the crane rails) and proposed in 40 CFR part 60, subpart AAb to revise the opacity limit to 0 percent to limit visible emissions from EAF and AOD that exit from the melt shop during all phases of operation.

b. Capture System, Baghouse, and Facility-Wide Total PM Control Device Emission Limit

The EPA proposed as the BSER a capture system and fabric filter. For the standard, we proposed a facility-wide mass-based PM limit from all EAF and AOD capture systems and control devices of 0.16 lb total PM per ton steel instead of a PM concentration limit that applies to each capture system and control device, which is the format of the current standards in 40 CFR part 60, subparts AA, AAa. As explained in the proposal, the EPA proposed a facility-wide mass-based PM limit because this form of standard was thought to result in better overall PM control and provide greater assurance of limiting PM emissions from the facility. Most importantly, if EAF emissions can be divided up into separate baghouses, for practical purposes or otherwise, with each device falling under the same NSPS PM limit based on air flow in gr/dscf, there is no accounting for the total PM emissions from the facility. A facility-wide total control device PM emissions limit in units of lb PM/ton of steel produced was expected to eliminate the disparity in control device emissions between low- and high-PM concentration exhaust, such as that for control devices for primary emissions (*i.e.,* directly from the EAF or AOD) v. secondary emissions (*i.e.,* from fugitive emissions), as well as the disparity between well-operated v. inefficiently-operated control devices in the cases where both types of control devices operate below the current individual baghouse limit in 40 CFR part 60, subparts AA, AAa.

To evaluate the BSER to reduce emissions from EAF and AOD capture systems and control devices, the EPA evaluated the baghouse air-to-cloth (A/C) ratio, expressed in units of volume of air flow per unit bag area (*i.e.,* cloth), using EAF facility baghouse model plants developed from the EPA dataset describe earlier in this preamble (87 FR 29718–29720). This was done to evaluate BSER, of which cost is a factor. The A/C ratio is generally accepted as the most important design parameter between baghouses of different performance levels, where a low A/C ratio is considered to be the best level of control (less air and more baghouse filter cloth) and a high A/C ratio is a low or poor level control (high air volume and low baghouse filter area).

Using model plants developed from the EAF dataset and the EPA cost-estimating procedures,[4] an A/C ratio of 2.2 m/min (7.2 ft/min) leading to a value of 0.16 lb total PM per ton steel produced was determined to be cost effective (87 FR29710). For a medium-sized model plant consisting of an EAF and all its baghouses, *i.e.,* EAF facility, emitting 0.16 lb PM/ton steel produced, the cost effectiveness at this lb/ton level was approximately $1,800 per ton PM removed $2020, an acceptable cost effectiveness, with an incremental cost effectiveness compared to a model plant at the next higher level of control (A/C ratio of 4.9 ft/min) at $8,500/ton $2020, which was not considered reasonable. Similar results were obtained for small and large EAF. Therefore, a facility-wide total 0.16 lb PM/ton steel produced limit from capture systems and control devices was proposed to represent performance level for the BSER for EAF and AOD capture systems and fabric filters for 40 CFR part 60, subpart AAb.

2. Requirement for Compliance Testing Every Five Years

We proposed that sources complying with 40 CFR part 60, subpart AAb would be required to perform compliance testing every 5 years after the initial testing performed upon startup, as required under 40 CFR part 60.8. This requirement already is required in many of the permits for existing EAF in the EAF dataset and in the industry, and also is a standard requirement for testing for other sources of PM emissions for many other industrial sectors.

3. Review of EAF NSPS Standards for Opacity From EAF Control Devices and Dust Handling Systems

The current NSPS standards for EAF in 40 CFR part 60, subparts AA and AAa, require less than 3 percent opacity from control device (baghouse) exhaust and less than 10 percent for dust handling procedures. We proposed to retain these limits in 40 CFR part 60, subpart AAb. (87 FR 29720–29721). In reviewing the EAF dataset, the EPA based these limits on the fact that no facilities reported lower levels of opacity for these sources, nor were lower levels required in any permits for these or any other EAF facilities. In addition, commensurate with determinations reported in the RACT/BACT/LAER Clearinghouse,[5] the current levels for baghouse exhaust (9 facilities) and dust handling systems (3 facilities) in 40 CFR part 60, subparts AA, AAa were considered BACT. Therefore, we concluded in the proposal that the opacity standards for control device exhaust and dust handling systems would remain the same.

4. Startup, Shutdown, Malfunction Exemption Removal From 40 CFR Part 60, Subpart AAb

The NSPS general provisions (40 CFR 60.11(c)) currently exclude opacity requirements during periods of startup, shutdown and malfunction (SSM). We proposed that opacity limits in 40 CFR part 60, subpart AAb would apply at all times along with all other emissions limits and standards, as provided in 40 CFR 60.11(f), because we concluded in the proposal that there were no technical limitations known to prevent new, reconstructed, or modified facilities from meeting all standards at all times. The language overriding the general provisions SSM opacity exemption was proposed for 40 CFR part 60, subpart AAb at 40 CFR 60.272b(c).

In its 2008 decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the United States Court of Appeals for the District of Columbia Circuit 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 40 CFR 63.6(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 CAA section 112 standards apply continuously. The EPA has determined the reasoning in the court's decision in *Sierra Club* applies equally to CAA section 111 because the definition of emission or standard in CAA section 302(k), and the embedded requirement for continuous standards, also applies to the NSPS. Therefore, consistent with *Sierra Club,* we proposed the NSPS standards in the 40 CFR part 60, subpart AAb would apply at all times.

5. Electronic Reporting for 40 CFR Part 60, Subparts AA, AAa, and AAb

The EPA proposed the requirement that owners and operators of EAF and AOD subject to the current and new NSPS at 40 CFR part 60, subparts AA, AAa, and AAb submit electronic copies of required performance test reports and any semiannual excess emissions and continuous monitoring system performance and summary reports, through the EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI). The proposed rule required that performance test/demonstration of compliance results collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the ERT website[6] at the time of the test be submitted in the format generated through the use of the ERT or an electronic file consistent with the xml schema on the ERT website, and other performance test/demonstration of compliance results be submitted in portable document format (PDF) using the attachment module of the ERT.

For semiannual reports, the proposed rule required that owners and operators use the appropriate spreadsheet template to submit information to CEDRI. The final versions of the templates for these reports are included in the docket for this action.[7] Additionally, the EPA identified the circumstances in which electronic reporting extensions may be provided.

B. Proposed Changes to Current NSPS, 40 CFR Part 60, Subparts AA and AAa

We proposed the following amendments and requested comments on the existing NSPS rules for EAF, 40 CFR part 60, subpart AA, and EAF and AOD, 40 CFR part 60, subpart AAa, to update, correct, or clarify these rules to enhance compliance and enforcement.

- Amendments to clarify and refine the rule requirements in 40 CFR part 60, sections 60.271 and 60.271a ''Definitions'', 60.272 and 60.272a

[4] *Cost Analyses to Determine BSER for PM Emissions and Opacity from EAF Facilities.* D.L. Jones, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, and G.E. Raymond, RTI International, Research Triangle Park, North Carolina. May 1, 2023 (Docket ID No. EPA–OAR–2002–0049).

[5] See *https://www.epa.gov/catc/ractbactlaerclearinghouse-rblc-basic-information* for more information. RACT, or reasonably available control technology, is required on existing sources in areas that are not meeting national ambient air quality standards (*i.e.,* nonattainment areas); BACT, or best available control technology, is required on major new or modified sources in clean areas (*i.e.,* attainment areas); and LAER, or lowest achievable emission rate, is required on major new or modified sources in nonattainment areas. See the RACT/BACT/LAER determinations made for EAF in the cost memorandum prepared for proposal (03–01–22); Docket ID No. EPA–HQ–OAR–2002–0049–0060.

[6] *https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert.*

[7] See 40 CFR part 60, subpart AA, AAa, and AAb, *Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels,* 40 CFR part 60.276(g) Semiannual Compliance Report Spreadsheet Template, available at Docket ID No. EPA–HQ–OAR–2002–0049–0064.

''Standard for particulate matter'', 60.273 and 60.273a ''Emission monitoring'', 60.274a ''Monitoring of operations'', 60.275a ''Test methods and procedures'', and 60.276a ''Recordkeeping and reporting requirements''.

• Minor revisions to clarify the rule and enhance compliance and enforcement.

• Solicited comments, data, and other information on whether the EPA should change the time to both find and fix the cause of a BLDS alarm from 3 hours to a longer timeframe (*e.g.,* 24 hours as in other rules), or some other duration.

• Requirement that owners and operators of EAF facilities submit electronic copies of required performance test/demonstration of compliance reports and semiannual reports through the EPA's CDX using the CEDRI and ERT.

• Requirement that performance test/demonstration of compliance results collected using test methods that are supported by the EPA's ERT as listed on the ERT website[8] at the time of the test be submitted in the format generated through the use of the ERT or an electronic file consistent with the xml schema on the ERT website, and other performance test/demonstration of compliance results be submitted in PDF using the attachment module of the ERT.

• For semiannual reports, requirement that owners and operators use the appropriate spreadsheet template to submit information to CEDRI.

IV. What actions are we finalizing, and what is our rationale for such decisions?

The EPA is finalizing revisions to the NSPS for EAF and AOD at steel plants pursuant the CAA section 111(b)(1)(B) review. The EPA is promulgating the NSPS revisions in a new subpart, 40 CFR part 60, subpart AAb that are applicable to affected facilities constructed, modified, or reconstructed after May 16, 2022. The new subpart reflects a BSER for a PM capture system and fabric filter, and a total facility limit for PM from control devices in units of lb PM/ton steel produced, and a canopy hood to capture melt shop VE, and a 0 percent opacity limit during melting and refining.

We also are finalizing results of the review of opacity from control device exhaust and from dust handling systems to keep same BSER and limits as in 40 CFR part 60, subpart AAa of 3 percent and 10 percent, respectively; that the emission limits would apply at all times; periodic compliance testing at least once every 5 years; and electronic reporting.

The facility-wide PM limit of 0.16 lb/ton as finalized will apply to all EAF and AOD control devices subject to 40 CFR part 60, subpart AAb and also all the air pollution control equipment used to remove particulate matter from the effluent gas stream generated by the EAF and AOD. The melt shop opacity standard of 0 percent as finalized will apply during the melting and refining period, and a 6 percent opacity limit will apply during the charging period and during the tapping period, with daily opacity or VE testing required during all 3 periods. We are finalizing that the PM limit of 0.16 lb/ton standard apply at all times, including during SSM, and that an opacity limit will also apply at all times (*i.e.,* 6 percent opacity during charging and tapping and 0 percent opacity at all other times). We are finalizing the requirement to submit the required compliance test reports through CDX using CEDRI and the ERT.

We also are finalizing clarifications and corrections to the 2 existing EAF rules: 40 CFR 60 subpart AA, Standards of Performance for Steel Plants: Electric Arc Furnaces Constructed After 10/21/74 & On or Before 8/17/83; and 40 CFR 60 subpart AAa, Standards of Performance for Steel Plants: Electric Arc Furnaces & Argon-Oxygen Decarburization Constructed After 8/17/83 and On or Before May 16, 2022. For these rules, we are finalizing amendments to certain parts of the current NSPS standards and to allow 24 hours for owners and operators a find and fix the cause of a BLDS alarm.

A. NSPS Requirements for PM Emissions From Control Devices for Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After May 16, 2022

1. What did we propose as the BSER determination and standard of performance for PM emissions from EAF control devices?

We proposed that BSER for new, modified, and reconstructed EAF and AOD sources is a capture system and fabric filter. We proposed that the PM limit that reflects BSER is a total facility emission rate of 0.16 lb PM/ton of steel from control devices at an affected facility. The EPA proposed a facility-wide mass-based PM limit from all EAF and AOD control devices per ton of steel produced instead of a PM concentration limit based on mass of PM per control device air flow that applies to each control device, which is the format of the standards in 40 CFR part 60, subparts AA, AAa.

2. What significant comments did we receive and what are our responses?

Comment: One commenter asserted that the form of the standard should not be changed from the original form of the standard in NSPS subpart AAa. The commenter stated for the NSPS subpart AAa rulemaking, the EPA rejected a production-based (or mass-based) standard in favor of a concentration-based limit in a NSPS proposed rule that was published on August 17, 1983. The commenter notes that, in that 1983 FR document, the EPA stated:

''A process weight format is based on a direct relationship between the quantity of pollutant emitted and the amount of input material consumed or product produced. Because of wide differences between EAF and AOD shops in operating procedures, such as the length of the steel production cycle, grade of steel produced, control technologies, vessel capacities, and other operating parameters, a simple direct relationship between mass emissions and steel production does not exist. Therefore, a process weight format was not selected for control devices regulated by the proposed standards.''

''Methodology to measure the concentration of emissions discharged to the atmosphere from control devices is readily available and well demonstrated. Concentration measurements are obtained directly from the stack emission test data. A concentration standard can be met equally well by a large or a small shop and by carbon and specialty steel shops. Consequently, a concentration format (*i.e.,* mass emissions per unit volume of gas) was selected for control devices regulated by the proposed standards to ensure control of captured process and fugitive emissions.'' (48 FR 37347)

The commenter continued that the EPA provides no explanation for the change in its position and fails to address the rationale the Agency provided in 1983 for adopting the current grain-loading standards in NSPS subpart AA and NSPS subpart AAa.

Another commenter added that the EPA's failure to justify this ''depart[ure] from a prior policy'' would render abandonment of the current concentration-based standard ''arbitrary and capricious,'' citing to *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502, 515–16 (2009).

EPA Response: The EPA disagrees with the comment that the EPA did not provide an adequate explanation for changing the form of the standard from

[8] *https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert.*

concentration-based to a production-based limit. The new format of the EAF NSPS subpart AAb, in units of lb/ton, ensures compliance as well as ensures that every facility is accountable for the total PM contribution from its EAF to the environment in the nearby community for every unit of steel produced. The EPA fully explained its justification for use of lb/ton format in the 2022 proposal, as follows here.

In the 2022 proposal, we explained that the emissions, and, hence, collected PM, from baghouses that control only secondary emissions can be much lower than the other two types of baghouses, as seen in the EAF dataset where the baghouse with the lowest PM emissions controlled only secondary emissions (87 FR 29715). We also explained that because of the inherent lower baghouse PM input (loading), secondary baghouses can be operated inefficiently without exceeding the current NSPS limit, which is expressed in the units of mass PM per unit of control device exhaust air. In addition, where there is a standard in terms of mass PM per unit of total exhaust air, baghouse dilution air (added to EAF exhaust air) can be increased with the effect of lowering measured baghouse PM emission concentration and disguising the true performance of the baghouse.

Further, at 87 FR 29715, the EPA proposed to set a facility-wide PM limit instead of a limit that applies to each control device (the format of the current standard) because we think this form of standard will result in better control and provide greater assurance of compliance. Most importantly, if EAF emissions can be divided up into separate baghouses, for practical purposes or otherwise, with each device falling under the same NSPS PM limit, there is no accounting for the total PM emissions from the facility. A facility-wide total control device PM emissions limit in units of lb of PM per ton of steel produced also would alleviate the potential disparity in control device emissions between low-and high-loading control devices, such as that for control devices for primary v. secondary emissions, as well as for well-operated v. inefficiently-operated control devices that both operate below the individual baghouse limit (87 FR 29715). Therefore, we did adequately explain our change in position at the proposal and also explained why we now think a facility-wide limit is more protective than a concentration-based limit, thereby satisfying the standard in *Fox Television*. See 556 U.S. at 515–16 (when the Agency acknowledges change in position, ''it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the Agency believes it to be better, which the conscious change of course adequately indicates'').

The commenter did not include any current data showing the lack of a direct relationship between mass emissions and steel production. The graphs in Figure 1 from the memorandum titled *Particulate Matter Emissions from Electric Arc Furnace Facilities,*[9] hereafter called the ''Emissions Memorandum,'' show a similar curve shape when data for the total EAF facility average concentration of PM in gr/dscf from the 2010 EPA/EAF data set[10] are plotted compared to the same PM data expressed as lb/ton PM emissions.

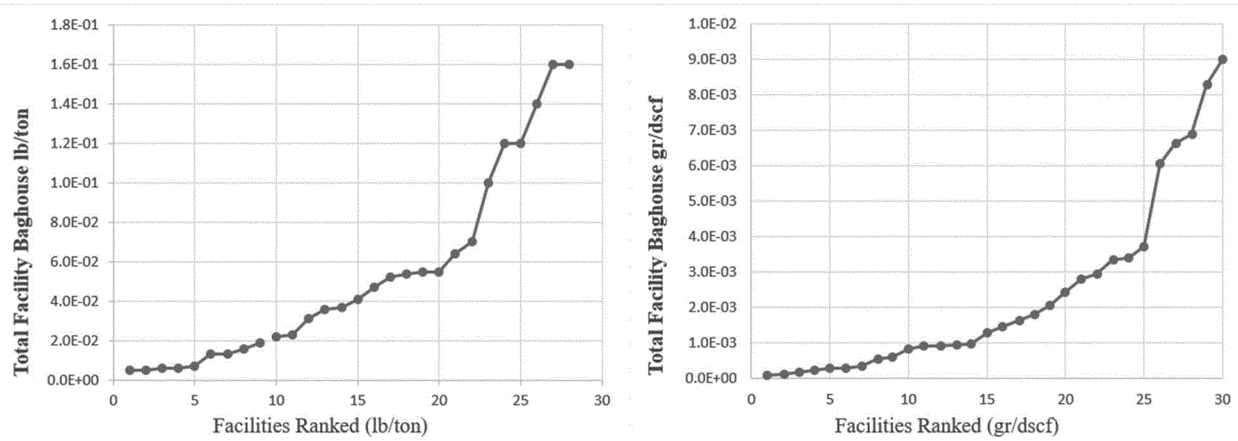

Figure 1. Curves of PM in gr/dscf and lb/ton for All 30 EAF Facilities in EPA EAF Dataset

In 1973, the EPA originally presented a NSPS standard in units of lb/hr-ton during the National Air Pollution Control Technical Advisory Committee (NAPTAC) meeting when the EAF NSPS was first being developed, as described in the 1974 *Background Information for Standards of Performance*[11] (BID). On February 22, 1973, the Agency presented to the National Air Pollution Control Techniques Advisory Committee (NAPCTAC) a draft standard PM limitation of 0.06 lb/hr-ton. However, this standard was ultimately not used by the EPA for the NSPS because of the industry objections with the lb/ton format and interest in the concentration-based limit.

It should be noted that the first promulgated NSPS limit, at 0.0052 gr/dscf, was based on test data from only

[9] *Particulate Matter Emissions from Electric Arc Furnace Facilities.* D.L. Jones, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, and G.E. Raymond, RTI International, Research Triangle Park, North Carolina. May 1, 2023. (Docket ID No. EPA–OAR–2002–0049–0061).

[10] In 2010, the EPA acquired EAF data from approximately 30 EAF facilities via a CAA section 114 test and information request. These data are located in the docket for the EAF NESHAP, 40 CFR part 63, subpart YYYYY at *https://www.regulations.gov/docket/EPA-HQ-OAR-2004-0083* and incorporated by reference into the docket for the EAF NSPS at *https://www.regulations.gov/docket/EPA-HQ-OAR-2002-0049.*

[11] *Background Information for Standards of Performance: Electric Arc Furnaces in the Steel Industry, Volume 1: Proposed Standards.* Publication No. EPA–450/2–74–017a. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina (October 1974).

one facility, as described in the 1974 BID [12] for EAF under 40 CFR part 60, subpart AA, the original EAF NSPS.

Preliminary investigations for the NSPS identified 30 plants from a review of the literature and contacts with industry, a described in the 1974 BID, discussed earlier in this section. From these 30 plants, 11 plants were identified that reportedly were well-controlled for PM emissions. Ten of the 11 facilities were visited, their visible emissions evaluated, and information obtained on the process and control equipment. Although many of the 11 plants practiced good control techniques, the facilities at only 3 plants (Plants A, I and J) were amenable to testing with EPA Method 5. Other facilities were not suitable for emission measurements because they use positive pressure baghouses, which have no stacks. Although development work was in progress, sampling methodology for this type of installation had not been standardized. These 3 plants were nearly identical except for size. They all produced alloy steels and controlled PM emissions with a building evacuation system. Each had a fabric filter control device that exhausted through multiple stacks. Rather than spread the test program effort over 3 tests at nearly identical plants, it was decided a more comprehensive test of one plant would provide more information. The middle-sized plant offered the best possibilities for this comprehensive test. Its size was typical of the mid-range for the industry, and the fabric filter did not have an inordinately large number of exhaust stacks.

To show that a mass-based limit has been considered by the EPA previously, the chronological history of the EAF NSPS subpart AA and AAa standards for PM from control devices, as taken from the 1974 BID, discussed earlier in this section, is as follows:

• In 1972, 299 EAF's in the United States were operated by 99 companies at 121 locations. On February 22, 1973, the Agency presented to the NAPCTAC a draft standard PM limitation of 0.06 pound per hour-ton (lb/hr-ton). Steel industry representatives attending the meeting suggested that the PM standard should be 0.244 lb/hr-ton.

• On May 30 and 31, 1973, at another NAPCTAC meeting, the EPA presented a revised draft technical report and standard. The PM standard presented by the EPA was changed from 0.06 lb/hr-ton to 0.10 lb/hr-ton. The industry representatives at the meeting suggested that the standard be expressed on a concentration basis and be set at 0.008 grains per dry standard cubic feet (gr/dscf) for a dry collector (*e.g.,* baghouse or fabric filter) and 0.02 gr/dscf for a wet collector (scrubber).

• At the January 9, 1974, NAPCTAC meeting, available emission data indicated that a 0.0039 gr/dscf PM standard could be easily achieved. These data were supported by a vendor guarantee of 0.004 gr/dscf on fabric filters at 3 building evacuation systems at 3 similar shops. These shops, owned by one company at one location, produced alloy steel. Another vendor also signed a statement that they would guarantee 0.004 gr/dscf on a system planned for the capture of charging and tapping emissions at a plant which produced carbon steel. Two other vendors stated that although 0.004 gr/dscf was achievable for fabric filters designed to treat large volumes of exhaust gas with low concentrations of PM, it could not be guaranteed, but 0.004 gr/actual cubic feet (acf), approximately equivalent to 0.005 gr/dscf, could be guaranteed. Further, industry representatives at the meeting commented that the 0.0039 gr/dscf level was too stringent for the industry to meet at all times. Therefore, the industry representatives suggested the limitation be 0.008 gr/dscf.

• After the January 9, 1974, NAPCTAC meeting, a vendor stated that, for a fabric filter controlling a direct shell evacuation (DEC) system with a relatively high inlet concentration of PM, 0.005 gr/dscf was a reasonable level to guarantee.

• In the October 21, 1974 proposal (39 FR 37466), the Agency proposed a PM standard to be no more than 0.0052 gr/dscf of PM from the control device, which relaxed the previous presented value of 0.0039 gr/dscf for the limit for the PM concentration emitted from an EAF control device.

In summary, this history of discussions around the first PM limit for EAF control devices in the NSPS is as follows: the EPA originally put forward an EAF control device standard in the form of lb/hr-ton in 1973. The following year, industry suggested a PM limit of 0.008 gr/dscf and vendors presented a guaranteed fabric filter limit of 0.005 gr/dscf. Subsequently, in 1974, the EPA proposed a standard of 0.0039 gr/dscf, which was based on ''available emission data'' from one facility, as noted in the 1974 BID. However, after NAPCTAC discussions with industry and vendors, a limit of 0.0052 gr/dscf was promulgated by the EPA in 1975 in the EAF NSPS subpart AA and confirmed again in 1984 in the EAF NSPS subpart AAa.

Regardless of the EPA's discussions during prior rulemakings, as detailed in the proposed rule and in this final action, we now have a strong basis to find a direct relationship between mass emissions and steel production that justifies our facility-wide PM limit in units of lb/ton. We show in our analyses of 2010 data from 30 facilities discussed in this preamble (see Figure 1), as well as in data from more facilities from 2005, as discussed in another EPA response in this preamble section, that there is a direct relationship. As explained earlier in section IV.A.1 and in other comments in this section, and in the proposal, the EPA analyzed the total facility PM mass emissions versus production at a number of EAF facilities and found that a correlation exists, and that promulgating a PM standard for NSPS subpart AAb in this form would enhance compliance and may reduce emissions. As noted earlier in this EPA response, the new format of the EAF NSPS subpart AAb, in units of lb/ton ensures that every facility is accountable for the total PM contribution from its EAF and AOD to the environment in the nearby community for every unit of steel produced. As an example of similar thoughts on the value of EAF standards in lb/ton, we note a 2017 facility construction permit for prevention of significant deterioration that included a lb/ton PM limit (0.19 lb/ton), as well as a ''no visible emissions'' limit for the EAF.[13]

Comment: The commenter asserted that the EPA conducted evaluation on a concentration basis and not in the form of the proposed standard (lb/ton). A commenter stated the EPA in its proposal performed cost analyses based upon the air flowrates to the air pollution control device, and rather than establishing a standard of performance for the air pollution control device (baghouse), the EPA proposed the PM emissions standard in terms of lb/ton steel produced on a facility-wide basis. The EPA analyzed the performance of emissions controls from EAF on a concentration basis (milligram per dry standard cubic meters (mg/

[12] *Background Information for Standards of Performance: Electric Arc Furnaces in the Steel Industry, Volume 1: Proposed Standards.* Chapter V. Summary of the Procedure For Developing Standards, Section D, Plant Inspections. Publication No. EPA–450/2–74–017a. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina (October 1974. pg. 63 (pdf pg. 88)).

[13] Finkl & Sons Co. DBA Finkl Steel—Chicago. 1355 East 93rd Street, Chicago, Illinois 60619. State of Illinois Clean Air Act Permit Program (CAAPP) Permit. ID No. 031600GUC. Permit No. 14030029. Permitting Authority, Illinois Environmental Protection Agency Bureau of Air, Permit Section 217/785–1705. Final issue date July 5, 2018. pp. 21 and 23 of 129.

dscm)—grain per dry standard cubic feet (gr/dscf))—and not in the form of the proposed standard. The EPA must be consistent with the basis of its evaluation and establish a standard measuring compliance as a concentration exiting the control device.

EPA Response: The commenter correctly notes that, rather than establishing a concentration standard of performance for each individual air pollution control device (baghouse), the EPA in 2022 proposed to set the PM emissions standard in terms of lb/ton steel produced on a facility-wide basis from all control devices at the EAF facility. However, the EPA disagrees that we analyzed the performance of emissions controls from EAF on a concentration basis (gr/dscf)—and not in the form of the proposed standard. The EPA's analysis in the ''Emissions Memorandum'' discussed earlier in this section clearly demonstrates that the EPA evaluated costs and emission reductions on a facility-wide basis in lb/ton format. [See figures and tables in the ''Emissions Memorandum'' discussed earlier in this section: Figure 3 (EAF baghouse data in mass PM per mass of steel produced (lb/ton)); Figure 4 (EAF facility total baghouse mass PM per mass of steel produced (lb/ton)); Table 3 (EAF Baghouse Information and Average PM Emissions (lb/ton)); and Table 5 (Facility Total EAF Baghouse Average PM Emissions (lb/ton))]. Further, the EPA outlined in multiple locations in the proposal that the performance of emissions controls from EAF were done on a facility-wide basis.

For example, at 87 FR 29716, the EPA described the PM and opacity test data that was used in the BSER analysis. At 87 FR 29715–29716, the EPA explained how the opacity limit was developed considering facility-wide emissions. To determine the PM limit for control device PM emissions under the BSER, the EPA only used data from EAF facilities with 0 percent melt shop opacity. This was because facilities that control their melt shop opacity to 0 percent are collecting more PM (specifically from the melt shop) than facilities that have a nonzero melt shop opacity and, as a result, are sending more PM to their control devices. Consequently, EAF facilities with 0 percent melt shop opacity are expected to have a slightly higher control device PM emission rate on average compared to EAF facilities with greater than 0 percent melt shop opacity, as evidenced by the EAF dataset of 33 EAF facilities. As a corollary, at EAF facilities with 6 percent melt shop opacity, some of the PM generated by the EAF is not captured, avoids the control device, and can exit through the melt shop roof, thus raising the melt shop opacity to above 0 percent. In turn, facilities with 6 percent melt shop opacity collect less PM and, therefore, less PM is sent to control device, which results in (slightly) lower PM emissions in the control device exhaust.

Overall, because of the large amount of PM emission differential between 6 percent and 0 percent melt shop opacity, much less PM is emitted to the environment with 0 percent melt shop opacity than with 6 percent opacity, despite the higher level of control device emissions with 0 percent melt shop opacity. This effect is described quantitatively in the proposal preamble (87 FR 29720). Of the 15 EAF facilities in the EPA dataset with 0 percent melt shop opacity, control device PM emissions data and steel production values needed to develop an emission standard in mass of PM per mass of steel production were available for 13 of the 15 facilities; these data included 51 individual tests from 23 baghouses and 21 EAF. The 13 EAF facilities and their PM emissions were used to demonstrate that 0 percent melt shop opacity is BSER and to develop a facility-wide total PM control device emission standard in lb/ton under the BSER for new, modified, and reconstructed EAF or AOD.

As explained earlier in section IV.A.1 and other comments in this section, and in the proposal, the EPA analyzed the total facility PM mass emissions versus production at a number of EAF facilities and found that a correlation exists, and that promulgating a PM standard for NSPS subpart AAb in this form would enhance compliance and may reduce emissions. As noted earlier in this EPA response, the new format of the EAF NSPS subpart AAb, in units of pound per ton (lb/ton), ensures that every facility is accountable for the total PM contribution from its EAF to the environment in the nearby community for every unit of steel produced.

Comment: A commenter asserted that a lb/ton steel limit does not consider the different types of EAF mills. A commenter stated the EPA does not acknowledge nor address the fundamental fact that a ''facility-wide lb/ton'' production, or mass-based standard, ignores the substantial differences among EAF steel mills that directly bear on the PM emissions per ton of steel produced. The commenter claims it is both unfair and inconsistent with the BSER to hold a small specialty steel EAF facility, with low tonnages and more time-intensive steel refining requirements, to the same production-based standard as a facility that produces 10-times or more steel with much shorter heat times (*i.e.,* 2 facilities with vastly different production rates).

The commenter stated a compliance method based on PM per ton of steel produced does not take into consideration the various subcategories of EAF operations, differences in steel products, and variation in heat times and tonnages produced, which vary considerably depending on the product grade of steel and the mix of such products at various mills. Some carbon EAF mills produce high tonnages in relatively short heat times, while specialty EAF steel facilities produce much smaller tonnages over heat times that can be 2 to 3 times as long.

The commenter continued, as the EPA noted in developing the NSPS subpart AAa standards in 1984, the production of steel in an EAF is a batch process where 'heats' or cycles range from 1 to 5 hours, depending upon the size and quality of the charge, the power input to the furnace, and the desired quality of the steel produced. The commenter added, the EPA's statement in the proposal that ''[t]he production of steel in an EAF is a batch process'' (87 FR 29713), is not accurate and fails to acknowledge ''Endless Charging Systems'' and Consteel® continuous feed systems (*i.e.,* continuous charging systems). The commenter added that, to determine appropriate standards of performance, the EPA should conduct a comprehensive evaluation of the different types of EAF mills (such as bar, sheet, and plate) and consider establishing different limitations and requirements for each subcategory. Another commenter encourages the EPA to evaluate current designs and applications of baghouses for the control of PM.

EPA Response: We disagree with the commenter on the relevance of lb/ton standard to the variation in EAF operations. The lb/ton limit being promulgated (0.16 lb/ton) reflects the highest emitting facility in the EPA dataset, which is a stainless steel facility. Therefore, we expect both EAF carbon and stainless steel facilities, continuous or batch, that modify or reconstruct and then are subject to the NSPS subpart AAb will be able to meet the new PM limit. Moreover, future new, reconstructed, and modified facilities will be in an even better position to meet this limit because they can plan their construction, reconstruction, or modification accordingly. For these reasons, and because the facility which represents the PM limit, at 0.16 lb/ton total facility PM control device emissions, is the highest emitting facility in the dataset (and 1 of only a total of 4 steel facilities in the industry that produce only stainless steel), we do not think a subcategory is warranted.

The commenter is correct that the lb/ton limit does not take into account the different types of EAF mills, but the various types of steel and production have all been meeting the single concentration standard in subpart AAa (and AA) without issue in the many years since this limit was first set in 1975. Therefore, meeting a lb/ton standard based on the emissions of one third of the facilities in the industry that also are meeting the current standard will not be a problem. Whether a mill is batch or continuous, slow or fast, will not affect the total amount of PM emitted per amount of steel produced for each facility. When a batch process stops producing steel (*i.e.,* stops tapping steel), it typically also will stop emitting PM from the EAF. If PM emissions continue after the EAF has stopped processing scrap, or steel has stopped being tapped in a batch process, any ''trailing'' PM emitted is still a result of the steel that has just been produced. Therefore, this ''trailing'' PM should be included in the total PM catch for the test run.

Similarly, a continuous EAF process will emit PM as it continues to produce steel. And a relatively large amount of steel produced in a short time will also produce a relatively large amount of PM in a short period. The effect of dividing the PM emitted by the tons of steel produced normalizes the different processes to a common lb/ton term.

Comment: Air-to-cloth (A/C) ratios from integrated iron and steel (II&S) industry were used instead of EAF data. The commenter asserted that the EPA offers no explanation why using II&S baghouse data was relevant to EAF baghouse controls in the first place or why the EPA presumed that relative rank placement of 5 facilities along a ranking of II&S baghouse A/C ratios allowed the EPA to presume those facilities' PM emissions were based on control through a baghouse with the same A/C ratios. Moreover, the commenter asserts that the use of II&S data is inexplicable because the EPA has in its possession the A/C ratios for many plants with EAF. This information was available to the EPA in the rulemaking docket for the 40 CFR part 63, subpart YYYYY NESHAP for EAF, and the EPA even summarized the A/C ratios for the EAF baghouses that were operated during these performance tests.

The commenter continued to assert that the EPA's derived average, median, minimum, and maximum A/C ratios are all incorrect. The derived A/C ratios misstate the actual A/C ratios reported by the 3 model facilities for which the EPA had actual performance test data (Model Plants A, B, and E). For instance, Model Plant E is the North American Stainless facility in Ghent, Kentucky (NAS–KY), which operates 4 baghouses. For those 4 baghouses, the facility reported to the EPA A/C ratios of 4.1, 4.5, 4.5, and 5.0 ft/min—none of which are close to the EPA's erroneously derived A/C ratio of 7.2 ft/min.

EPA Response: The EPA disagrees with the commenter's assertion that the use of II&S data in lieu of the A/C ratios for plants with EAF is inappropriate. The EPA stated in the EAF NSPS proposal (87 FR 29718) that the reason for using more recent 2011 II&S baghouse data was because no A/C ratio data were available in the EAF PM test reports from 2010. Therefore, values for A/C ratios from CAA section 114 responses submitted in 2011 by the II&S industry for the risk and technology review for 40 CFR part 63, subpart FFFFF (85 FR 42074) were used in the EAF BSER PM cost analysis. The baghouses used for emissions from furnaces in the II&S industry are expected to be similar in operation as the baghouses used at EAF/AOD for the purposes of this analysis.

The baghouse A/C ratios from in the NSPS proposal based on II&S data submitted in 2011 for a CAA section 114 request were similar to those submitted in 2005 for another CAA section 114 request for the EAF NESHAP (40 CFR part 63, subpart YYYYY),[14] as shown in Table 1. A quantitative comparison of the A/C ratios from the 2005 EAF NESHAP data to the II&S 2011 data is also shown in Table 1.

TABLE 1—COMPARING A/C RATIOS FOR 2011 II&S DATA V. 2005 EAF NESHAP

Model plant	A/C ratio (ft/min)		Comparing 2011 II&S A/C data to 2005 NESHAP data	
	2011 II&S	2005 EAF NESHAP		
A	1.3	1.4	−7 percent	II&S lower.
B	2.9	2.2	32 percent	II&S higher.
C	4.0	3.0	33 percent	II&S higher.
D	4.9	4.5	9 percent	II&S higher.
E	7.2	6	20 percent	II&S higher.
Average			17 percent	II&S higher.

As the commenter points out, the 2005 EAF data does not include all of the facilities from the 2010 dataset. In addition, the 2005 data did not have A/C data for all the facilities' baghouses, where there were multiple baghouses, and for some facilities the number of baghouses for each facility changed from 2005 to 2010.

In response to this comment, for the final rule, we re-examined the BSER analysis of total facility PM lb/ton steel from capture systems and fabric filters using A/C ratios from the EAF 2005 CAA section 114 request that ranged from 1.4 to 6.0 ft/min. For Model Plant A, corresponding to Timken-Faircrest-OH, the A/C ratio in the 2005 CAA section 114 request (3.4 A/C) was higher than the 2011 II&S data point (at 1.3 A/C), but the A/C ratio derived using a regression analysis that produced the line of best fit from the 2005 CAA section 114 request data (at 1.4 A/C), is very similar to the II&S datapoint (1.3 A/C).

For Model Plant B, based on Timken-Harrison-OH, the A/C ratio from the 2005 CAA section 114 request (at 2.7 A/C) is very similar to the II&S data point (2.9 A/C) and also from a regression analysis that produced the line of best fit from 2005 (2.7 A/C).

For Model Plant E, based on NAS-KY, an average A/C ratio of 4.5 ft/min A/C was derived from the data reported to the EPA in 2010 (and also provided by the commenter). However, the A/C ratio of 6.0 assigned to the same emissions as

[14] Docket ID No. EPA–HQ–OAR–2004–0083.

NAS-KY (0.16 lb/ton) derived from the curve of 2005 CAA section 114 data is not much different than what was used in the EAF proposal (at 7.2 A/C) based on II&S data. These values are shown in Table 2.

TABLE 2—COMPARING A/C RATIO DATA BETWEEN 2005 AND 2010 EAF DATA AND 2011 II&S DATA

Facility	Comparing 2005 to 2010 data	Model plant	A/C ratio (ft/min)			
			2011 II&S data	2005 EPA data	2010 EPA data	Curve using 2005 data
Timken-Faircrest-OH	Different baghouses	A	1.3	3.4	NA	1.4
Timken-Harrison-OH	Same baghouses	B	2.9	2.7	NA	2.2
NAS-Ghent-KY	Same baghouses	E	7.2	NA	4.5	6.0

In addition, the EPA used the data from the 2005 CAA section 114 request for the EAF NESHAP to add to the 2010 CAA section 114 request data used for the lb/ton BSER PM limit analyses for capture systems and fabric filters reported in the proposal in order to re-evaluate the proposed lb/ton BSER standard for capture system and fabric filter PM emissions. The 2005 EAF emission data that was able to be converted to lb/ton values and also had A/C ratio data were used along with 2010 CAA 114 request data used to develop BSER for the proposal. A similar trend in PM lb/ton data was seen in the 2005 data as compared to 2010 data, as shown in Figure 2 below, with a lower maximum PM lb/ton value in the 2005 data.

The 2010 CAA section 114 request data used to develop the PM lb/ton standard for the proposal were matched to the A/C ratios in the 2005 CAA section 114 data for the NAS-Ghent-KY facility, to provide a total of 18 facilities in the dataset for PM lb/ton standard for capture systems and fabric filters for the final rule. See the memorandum titled *Cost Analyses to*

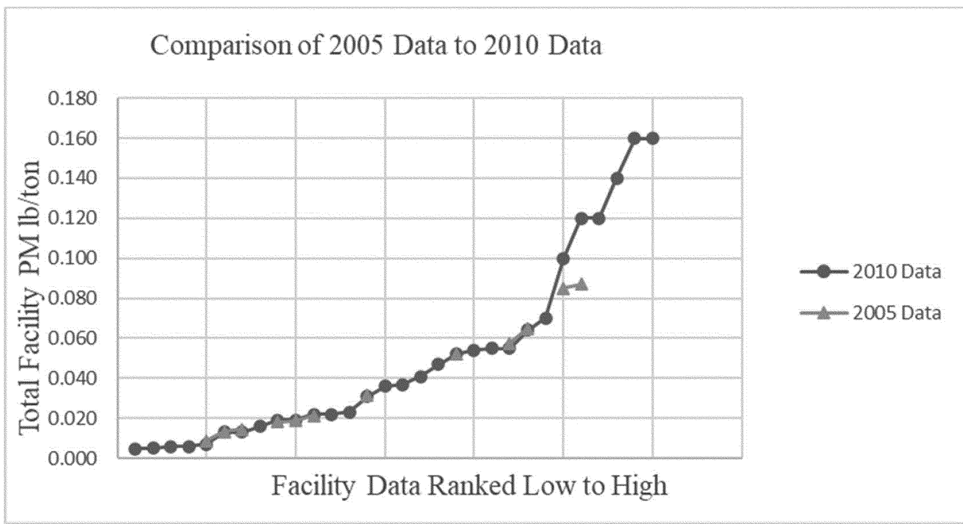

Figure 2. Comparison of 2005 and 2010 CAA Section 114 Request For Data for Total Facility Baghouse PM Emissions Per Mass of Steel Produced (lb/ton)

Determine BSER for PM Emissions and Opacity from EAF Facilities,[15] as updated for the final rule, hereafter referred to as the ''Cost Memorandum,'' located in the docket for this rule. The results of the analyses of a PM limit that reflects BSER were similar between proposal and final producing the same PM 0.16 lb/ton limit for the BSER capture system and fabric filter. See Table 3 for the combined 2005 and 2011 lb/ton data set using EAF A/C ratios and both 2005 and 2011 EAF submitted emissions data. Table 4 shows the results from the model plant analyses comparing the results for the 2 approaches. Note Model Plants E and F are both the highest emitting model plant in the proposal (using 2011 II&S A/C ratios) and final rule (Using 2005 EAF A/C ratios) analyses, respectively. Because Model Plants E and F are the highest emitting model plants, the EPA does not have a baseline with which to compare the costs and emission reductions in order to develop average cost effectiveness values. However, the EPA's determination of the BSER in this review is consistent with its determination of the BSER in the prior 40 CFR 60, subpart AAa rulemaking. And as noted elsewhere in this preamble, a third of the industry is already achieving the PM 0.16 lb/ton limit through application of that BSER, which demonstrates that the costs of meeting that limit are reasonable, and not exorbitant or excessive. See *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999) (''EPA's choice will be sustained unless the environmental

[15] *Cost Analyses to Determine BSER for PM Emissions and Opacity from EAF Facilities.* D.L. Jones, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, and G.E. Raymond, RTI International, Research Triangle Park, North Carolina. May 1, 2023; Docket ID No. EPA–OAR–2002–0049–0061.

or economic costs of using the technology are exorbitant.''); *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981) (the court is not inclined to ''quarrel'' with the EPA's judgment that ''forecasted cost was not excessive and did not make the cost of compliance with the standard unreasonable''); *Portland Cement Association* v. *Train,* 513 F.2d 506, 508 (D.C. Cir. 1975) (the inquiry is whether the costs of the standard are ''greater than the industry could bear and survive''). Moreover, the capital costs and annual costs associated with compliance with the PM 0.16 lb/ton limit are similar to, and in some cases lower than, the costs that the EPA found to be reasonable for implementing the BSER to meet the final opacity standard, discussed in section IV.B. See the ''Cost Memorandum,'' discussed earlier in this section, for details of both the canopy costs for the opacity limit and fabric filter costs for the PM limit. This further demonstrates that the costs of meeting the PM 0.16 lb/ton limit are also reasonable for this industry, for all facility sizes. However, as shown in Table 4, the EPA does not find the incremental costs of achieving the more stringent standards evaluated through application of the BSER to be cost effective for any facility size. Accordingly, the EPA concludes that PM 0.16 lb/ton limit reflects the degree of emission limitation achievable through application of the BSER.

TABLE 3—COMBINED 2005 AND 2010 lb/ton EAF DATASETS WITH 2005 EAF A/C RATIOS

Count	2010 Zero opacity facilities	2010 lb/ton	2005 facility A/C (weighted average)
1	Timken-Faircrest-OH	1.3E–02	3.4
2	Nucor-Crawfordsville-IN	1.6E–02	3.2
3	Gerdau-Charlotte-NC	2.3E–02	2.2
4	Timken-Harrison-OH	3.6E–02	2.6
5	Nucor-Huger-SC	5.2E–02	2.6
6	CMC-Birmingham-AL	5.5E–02	3.7
7	CMC-Cayce-SC	6.4E–02	3.3
8	NAS-Ghent-KY	1.6E–01	4.5 (2010)
Count	2005 Facilities with P/S Baghouses	2005 lb/ton	2005 Facility A/C (weighted average)
1	Nucor-Norfolk-NE	8.7E–03	2.8
2	Nucor-Cofield-NC	1.3E–02	3.0
3	Nucor-Blytheville-AR	1.4E–02	3.0
4	Nucor Bar Mill-Plymouth-UT	1.8E–02	2.1
5	North Star Steel-St. Paul-MN	1.9E–02	2.0
6	Nucor Berkeley-Huger-SC	2.2E–02	2.6
7	IPSCO Steel-Axis-AL	3.2E–02	2.6
8	SMI Steel-Cayce-SC	5.8E–02	3.3
9	CMC/Struct Metals/SMI-Sequin-TX	8.5E–02	6.0
10	IPSCO Steel-Muscatine-IA	8.7E–02	5.1

TABLE 4—COMPARISON OF BSER MODEL PLANTS FOR SMALL, MEDIUM, AND LARGE EAF FACILITIES USING TWO DATASETS: 2005 EAF A/C RATIOS AND 2010 II&S A/C RATIOS, BOTH WITH 2010 EAF lb/ton DATA

Model plant [a]	Total controlled EAF PM emissions	EAF facility average production	A/C ratio (ft/min)		Cost for new baghouse		Incremental cost effectiveness compared to next lower-emitting model plant [b]
	lb/ton	tpy	Value	Basis	Capital $	Annual costs $/yr	delta$/ton PM
Small Facility							
E	0.16	50,000	7.2	2011 II&S	$796,912	$341,981	$13,340
F	0.16	50,000	8.0	2005 EAF	767,439	338,610	7,196
Medium Facility							
E	0.16	775,000	7.2	2011 II&S	4,778,920	2,045,443	12,197
F	0.16	775,000	8.0	2005 EAF	4,361,224	1,997,701	6,575
Large Facility							
E	0.16	3,450,000	7.2	2011 II&S	21,929,003	8,598,613	13,708
F	0.16	3,450,000	8.0	2005 EAF	19,839,154	8,359,718	7,390

[a] Model Plants E and F are both the highest emitting model plants in the two datasets, where the A/C data for Model E is from II&S A/C data and for Model F the 2005 CAA section 114 responses are used for A/C data. Cost analysis values for Model E are the same as from proposal, with updates to reflect $2022 for the final rule v. $2020 that were used for the proposed rule.

[b] The incremental cost effectiveness from Model Plant E to D in $2022, at $12,200/ton for medium-sized facility, is higher than the same comparison of the same model plants in $2020, at $8,500/ton, because of the increase in the values used in the cost estimate as a result of inflation and increase in interest rate from 3.5 percent to 7.5 percent from 2020 to 2022.

Comment: The commenter asserted that the change from a concentration to lb/ton limit complicates compliance and does not result in better control or greater assurance of compliance. The commenter stated the EPA's assertion that switching to a lb/ton standard will ''result in better control and greater assurance of compliance'' is incorrect. Under the current standards in NSPS subparts AA and AAa, compliance is readily demonstrated through EPA Method 5 monitoring of the stack on the primary control device/baghouse. This is a direct measurement of the filtering ability of the baghouse and evidence of compliance with concentration limits without all of the unnecessary variables the new rule introduces which are not directly related to emissions. Under the proposal, facilities subject to NSPS subpart AAb would be required to track tonnages produced during stack tests and match those to emissions data.

EPA Response: The commenter is correct that with a lb/ton standard, facilities subject to NSPS subpart AAb will be required to track tonnages produced during stack tests and match those to emissions data. However, this is already required in the current EAF NSPS (compare 40 CFR 60.274(i)(1), 60.274a(h)(1) with proposed and final 40 CFR 60.274b(h)(1)). The 31 facilities in the 2010 EPA/EAF data set were able to report steel produced during the testing. Therefore, we expect the entire industry to be able to do so.

The baghouse PM emission data in gr/dscf do not address the total emissions generated by a facility. The gr/dscf data can be influenced by increasing dilution air to the baghouse and is not directly related to steel production as PM emissions logically should be. Using concentration in gr/dscf to assess the filtering ability of baghouses can still be done at any time but it doesn't necessarily reflect the contribution of PM by the facility's steel production to the environment. In order to assess a facility's impact to the local environment, the general public would need to know the exhaust rates of every baghouse at a facility to determine the facility's PM emissions, whereas from lb/ton facility-wide data, the maximum amount of PM being emitted can be easily ascertained with only one steel production value and one facility-wide PM limit.

Comment: The commenter asserted that the lb/ton limit does not consider vendor guarantees on control systems. The commenter stated it is critical to obtain vendor guarantees from suppliers when constructing new facilities or EAF and associated control systems, to ensure that the purchased equipment can comply with applicable standards. Vendors can guarantee that the filters/control device have a specific removal rate (*i.e.,* vendors can only guarantee the difference between the clean and dirty side of the bag). Obtaining such guarantees is what gives facilities comfort that the equipment they purchase will perform such that compliance is assured. The commenter stated that such comfort is not possible with the Agency's proposed ''facility-wide'' PM limit, because vendors do not offer lb/ton guarantees for specific equipment and certainly not on a facility-wide basis. This is understandable given a supplier's ability to design equipment to a given concentration or control specification, but lack of ability to control the many factors that influence lb/ton efficiency, especially where a vendor may not be the sole facility-wide designer. Vendors have no control over the tonnage of steel produced or how the steel tonnage estimate comports with the duration of the PM measurement. The commenter concluded the EPA should take this into account by setting a concentration-based emission standard and noted that the EPA has previously acknowledged the importance of being able to obtain vendor guarantees when setting the NSPS subpart AAa limits in 1984 (49 FR 43840). The commenter stated that it would thus be arbitrary and impermissible for the EPA to ignore that consideration here.

EPA Response: Vendors can continue to use gr/dscf to assess the filtering ability of a baghouse, especially since the NESHAP for EAF (40 CFR part 63, subpart YYYYY) still requires gr/dscf determinations. In addition, the calculation of PM concentration in gr PM/dscf is an intermediate step in the calculation of lb PM/ton steel emission rate: concentration (gr/dscf) * flow rate (dscf) = emission rate, as PM in lb/hr; then divide by tons per hour steel for lb PM/ton steel format. Moreover, evaluating the impact of a new facility (or reconstructed or modified facility) under the NSPS subpart AAb, in terms of PM emissions on the surrounding communities, is more easily determined from a lb/ton limit and overall facility steel production. With a lb/ton limit, not only must a new facility determine that their baghouses are working properly, but they must also determine whether the facility is being efficient in its generation of PM at the desired production level compared to the best facilities operating at the same production level.

Comment: A commenter noted that EAF National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR part 63 subpart YYYYY requires concentration limits. The commenter stated the maximum achievable control technology (MACT) standard in the NESHAP for EAF (40 CFR part 63, subpart YYYYY) independently limits PM emissions from each EAF to 0.0052 gr/dscf. The proposed NSPS would thus have the result of subjecting facilities to both a lb/ton limit (via NSPS) and a concentration limit (via NESHAP). Since facilities will still have to track gr/dscf anyway to comply with NESHAP limits, it would be inefficient and unreasonable to also require a lb/ton limit.

EPA Response: The applicability between the NSPS and NESHAP are different. All existing EAF facilities will continue to meet the gr/dscf PM limit in the NESHAP. Only new, reconstructed, or modified EAF or AOD units and their control devices need to meet both the lb/ton PM total facility limit that is being finalized in NSPS subpart AAb along with the NESHAP's individual baghouse limit. As discussed in previous responses to comments in this section, the data needed to show compliance with both standards are obtained in the same test. The combination of the two standards results in the public and regulators being able to more accurately evaluate EAF operation and the potential impact of new facilities on surrounding communities because the rules together limit total facility PM emissions impacts while checking individual control device operation. Facilities subject to the NSPS subpart AAb, and their vendors can continue use the gr/dscf limit to troubleshoot baghouse operation just as facilities have done in the past.

For facilities that modify or reconstruct after May 16, 2022, only the EAF(s) or AOD(s) and the air pollution control equipment that were modified or reconstructed after May 16, 2022, must comply with NSPS subpart AAb. This provision has been added to the rule at in 40 CFR 60.271b under the definition of ''*Electric arc furnace facility.*'' If there are capture systems and control devices that capture PM emissions from sources subject to NSPS subparts AA or AAa at the same site where there are also sources subject to NSPS subpart AAb, the procedures described in the rule at 40 CFR 60.275b(b) include any one of the following options (see also 40 CFR 60.276bI) to determine compliance: use the combined emissions; use a method that is acceptable to the Administrator or delegated authority and that compensates for the emissions from the facilities not subject to the provisions of this subpart; or any combination of the above methods.

3. What is the rationale for the final BSER determination and what is the final standard of performance?

The EPA is finalizing the proposed determination that the BSER for EAF and AOD is capture and control of PM with a fabric filer. The EPA is further finalizing the proposed determination that limit based on the BSER at 0.16 lb/ton total facility PM is achievable for any new, modified, or reconstructed facility because it is based on the EPA's data from approximately one third of the industry. The format of the limit based on BSER (total facility lb PM/ton steel produced from all affected capture systems and fabric filters) provides complete information on the performance of the facility and their EAF rather than that of just the individual baghouse(s) and individual EAF via a concentration based standard, and enables the public and regulators to know the total pollutant impact of the facility's EAF operation on the surrounding community. The current concentration-based limit in NSPS subparts AA and AAa is influenced by the amount of dilution air in the exhaust going through the baghouse, which can be adjusted to some extent by the facility without significant detriment to baghouse operation. Evaluating the impact of PM emissions from a new EAF facility (or reconstructed or modified facility) on the surrounding communities is more easily determined from a facility-wide lb/ton limit. With a lb/ton limit, not only must a new facility determine that their baghouses are working properly, but they must also determine whether the facility is being efficient in its generation of PM at the desired production level compared to the best facilities operating at the same production level. In addition, the total facility lb/ton PM limit provides an overall assessment of emissions from the facility in a format that scales emissions to production, which is based on fundamental engineering principles. The current concentration-based limits in NSPS subparts AA and AAa do not limit the air flow or the number of baghouses that could be used to comply with the standard.

Based on data from 31 EAF facilities (more than one third of the industry), all 31 facilities' baghouse emissions are 40 percent or lower than the current concentration-based limit in 40 CFR part 60, subparts AA, AAa. Therefore, the 0.16 lb/ton production-based limit based on these same data is a significant improvement in emissions control compared to the current standard. Moreover, because the lb/ton limit is the highest level in the EPA data set that includes one third of the industry, the standard that the EPA has determined to reflect the application of the BSER technology is achievable.

Lastly, we used both 2005 EAF PM data with EAF 2005 A/C data, and 2010 EAF PM data with 2005 EAF A/C data for the cost analysis to determine BSER for the EAF lb/ton PM standard, and reached the same conclusion as we did for proposal with 2010 EAF PM data and 2010 II&S A/C data. Therefore, in this final rule, the use of a capture system and fabric filter was determined as the BSER. The PM limit based on BSER of 0.16 lb PM/ton steel facility-wide was derived from the data available to the EPA, which comprised approximately one third of the industry, and also where the EPA considered costs, nonair quality health and environmental impacts, and energy requirements (described below in sections V.A and V.B).

4. Are there any relevant energy impacts or nonair quality health and environmental impacts of the selection of the final BSER and, if so, how were the final emission limitations based on BSER affected?

The EPA did not identify any relevant energy impacts or nonair quality health and environmental impacts of the proposed or final standards for PM emissions from EAF and AOD control devices (baghouses). See sections V.A and V.B. of this preamble for details. No comments were received on these issues.

B. NSPS Requirements for Opacity From Melt Shops for Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After May 16, 2022

1. What did we propose as the BSER determination and standard of performance?

We proposed that VE from EAF and AOD that exit from the melt shop would be limited to an opacity of 0 percent during all phases of operation, based on the determination of BSER as the addition of a partial roof canopy to capture and control melt shop fugitive emissions.

2. What significant comments did we receive and what are our responses?

Comment: One commenter asserted that the proposed 0 percent melt shop opacity limit disregards workers' safety by requiring the closure of roof and buildings. Specifically, the commenter stated the proposed 0 percent melt shop opacity limit disregarded workers' safety related to heat stress and material handling activities and that, therefore, the EPA should reconsider the 0 percent opacity limit. The commenter stated the proposal did not include an analysis of impacts for closure of building openings. A review of the impacts on worker heat stress would be necessary and that the EPA had provided no justification for requiring melt shops to close all openings.

The commenter noted the current proposed rule did not address heat stress concerns, which was in conflict with OSHA's current Heat Stress Initiative and National Enforcement Program that identified ''iron and steel mills'' specifically as a high hazard industry for heat stress. The commenter stated that safe melt shop operation requires air flow to minimize potential heat stress on workers and equipment. The commenter claimed that negative pressure alone was not sufficient to maintain proper airflow through the melt shop and that cross drafts were necessary and doors and other access points needed to be open. The commenter also had significant concerns about employee health impacts from the proposed totally enclosed melt shop, particularly for its Mobile, Alabama facility, which is located in an extreme climate area, as the proposed changes could cause greater heat stress on employees and would necessitate design and structural changes that the EPA failed to consider in its proposal. The commenter stated that 100 percent capture and 0 percent opacity may not be safe. The commenter noted when evaluating 2 different control systems, the EPA may not simply choose the most cost-effective air pollution control system if it potentially has adverse impacts on the health and safety of workers within the melt shop. The commenter stated that facilities need to allow air changes to protect worker health and safety.

The commenter referenced the 1984 amendments, which dismissed the option for a closed roof configuration to achieve 0 percent opacity due to the impacts of heat stress on worker safety and equipment functioning. A commenter said that statements made by the EPA in the 1984 40 CFR part 60, subpart AAa rulemaking (49 FR 43841) that ''the visible emission limits were selected-based on the performance of the capture and control technologies that served as the basis for Regulatory Alternative B (partially open roof monitor)'' and that ''Regulatory Alternative C (closed roof) was not considered suitable as the basis for national standards of performance because it is based on a closed roof configuration which may aggravate worker and equipment heat stress problems.''

EPA Response: The proposed rule 40 CFR part 60, subpart AAb did not require a closed roof nor a totally enclosed melt shop. In addition, the 0 percent shop opacity limit does not restrict air flow from exiting or entering the shop. Rather, the 0 percent opacity limit merely necessitates that no visible particles be emitted from the shop (as reflected by either no VE observations via EPA Method 22 or opacity of 0 percent using EPA Method 9 or the DCOT method). Canopy hoods have the benefit of being able to collect a large volume of emissions, especially those during charging and tapping and route the PM to control devices. Therefore, the basis for the addition of a partial roof canopy with a canopy hood used in the proposed and final cost estimates is to ensure facilities clean the air of particles before allowing the air to exit the shop opening(s). We believe a capture device such as a canopy hood, as opposed to a closed roof, can be used to meet the opacity limit based on BSER and does not endanger worker safety.

Comment: The commenter asserted that the EPA used a limited data set that was not indicative of continuous long-term performance and did not support a finding that 0 percent opacity was adequately demonstrated. The commenter stated the EPA's dataset for EAF steel mills is selective and not representative of the full scope of operations at these facilities. The commenter stated that the EPA purported to have based the proposed 40 CFR part 60, subpart AAb shop opacity limit on individual performance testing reports from a total of 13 of 31 EAF steel mills, which was less than half. The commenter noted that most facilities (16 out of 31) were unable to maintain 0 percent shop opacity throughout the duration of the performance tests. Thus, as the majority of facilities in the EPA's database did not maintain 0 percent opacity, the short duration of performance testing plainly demonstrated that 0 percent shop opacity was not adequately demonstrated.

Another commenter stated the EPA's proposal of 0 percent opacity from the melt shop was based on limited information from opacity tests conducted at 31 facilities, of which less than half achieved the 0 percent melt shop opacity requirement. The commenter stated that the short-term observations conducted during a stack test were taken for a few hours under a specific set of conditions and were not representative of long-term compliance capability and, as such, could not account for routine operating variability and the full range of operating conditions that may affect opacity. The commenter stated that the subset of data the EPA relied upon did not include longer-term operating performance of the identified mills; yet NSPS, as defined by BSER, must account for what was achievable and adequately demonstrated by a wide variety of facilities operating under a wide variety of conditions, not simply show that the standard was achieved at a model plant for a short period of time. The commenter also noted that the data collected by the EPA generally showed that the more years of opacity data reviewed for a given facility, the higher the maximum melt shop opacity.

EPA Response: Thirteen facilities out of the 31 EAF facilities in the EPA data set had 0.00 percent shop opacity during the tests which were reported to the EPA. Two additional facilities in the EPA data set achieved 0.00 percent shop opacity as shown in the submitted test reports and another 4 facilities achieved 0.0 percent as shown in the submitted test reports, for a total of 19 facilities appearing to already be complying with a 0 percent shop standard (1 significant figure) based on tests in the submitted reports, and which were performed using the same test method that would be required to show compliance with the NSPS. Out of the total 31 facilities in the EPA EAF data, only 1 facility had shop opacity greater than 1 percent as an average of all runs in the test, with the overall average among the 31 facilities in the EPA data set at 0.14 percent opacity. See the list of 31 EAF facilities and the opacity test results from reports submitted to the EPA in the 2010 EPA/EAF data set, as shown in Table 5. None of the opacity data submitted to the EPA in 2010 should be construed as being from a ''model plant.'' The opacity data was taken from facilities responding to the CAA section 114 information request with the primary purposes to obtain mercury emissions data and were real facilities, comprising a third of the industry. Data for PM and opacity were collected as part of the CAA section 114 information request only for purposes of showing that the reported mercury data were taken during the time the facility was complying with both the NESHAP (40 CFR part 63, subpart YYYYY) and NSPS (40 CFR part 60, subparts AA and AAa).

TABLE 5—RANGE OF MELT SHOP OPACITY IN 31 EAF TEST REPORTS (2005–2011) FROM THE 2010 CAA SECTION 114 REQUEST

[2010 EPA/EAF Data Set]

Count	Facility ID	Melt shop opacity (percent)
1	AKS-Butler-PA	0.000
2	AKS-Mansfield-OH	0.000
3	CMC-Birmingham-AL	0.000
4	CMC-Cayce-SC	0.000
5	CMC-Mesa-AZ	0.000
6	Ger-Charlotte-NC	0.000
7	Ger-Jackson-MI	0.000
8	NAS-Ghent-KY	0.000
9	Nuc-Crawfordsville-IN	0.000
10	Nuc-Huger-SC	0.000
11	Nuc-Jewett-TX	0.000
12	Nuc-Marion-OH	0.000
13	SSAB-Axis-AL	0.000
14	Tim-Faircrest-OH	0.000
15	Tim-Harrison-OH	0.000
16	Nuc-Darlington-SC	0.001
17	Ger-Knoxville-TN	0.01
18	Ger-StPaul-MN	0.02

TABLE 5—RANGE OF MELT SHOP OPACITY IN 31 EAF TEST REPORTS (2005–2011) FROM THE 2010 CAA SECTION 114 REQUEST—Continued

[2010 EPA/EAF Data Set]

Count	Facility ID	Melt shop opacity (percent)
19	Nuc-Plymouth-UT	0.05
20	CMC-Seguin-TX	0.10
21	Ger-Wilton-IA	0.10
22	Ger-Jacksonville-FL	0.10
23	Ger-Jackson-TN	0.20
24	Alle-Brackenridge-PA	0.20
25	Nuc-Cofield-NC	0.20
26	Alle-Latrobe-PA	0.30
27	Nuc-Blytheville-AR	0.30
28	Nuc-Norfolk-NE	0.30
29	Ger-Beaumont-TX	0.50
30	Ger-Cartersville-GA	0.80
31	Ster-Sterling-IL	1.2
	Overall average	0.14

It would be exorbitantly expensive to the industry (as well as the EPA) for the EPA to request and analyze round-the-clock opacity testing throughout the course of years at a number of facilities in order to obtain data during a ''wide variety of conditions and wide variety of facilities.'' None of the opacity requirements in previously promulgated rules (40 CFR part 60, subparts AA and AAa) have differentiated conditions or facility types for the opacity requirements in those rules. The commenter does not provide any information showing that the need for these data is justified, except for alluding to the fact that facilities improved their control of opacity in more recent years.

The goal of determining BSER is that it is the ''best'' system of emission reduction (considering costs and other factors), not the system used by the majority of the industry nor the top facilities when ranked or any other ranking method. However, the EPA acknowledges that the data obtained through CAA section 114 requests consisted of data collected during melting and refining, which is the time period required to test opacity in the current EAF NSPS rules in 40 CFR part 60, subparts AA, AAa. Therefore, in light of comments provided by the industry that reducing opacity during charging and tapping is difficult to achieve because of the physical structure of equipment and because of the much higher PM emissions during charging and tapping than during melting and refining, in the final rule for 40 FCR part 60, subpart AAb we are maintaining the current rule limit in 40 CFR part 60, subparts AA, AAa of 6 percent opacity to apply during charging and tapping, and retaining the proposed 0 percent melt shop opacity for melting and refining. We estimate that the period of charging and tapping is approximately 15 percent of the total EAF operating time period.

Comment: The commenter asserted that the EPA's limited data set is not representative of performance during ''charging and tapping''; 0 percent opacity should not apply to charging and tapping. The commenter stated the EPA's opacity data set did not adequately demonstrate that a 0 percent opacity limit could be consistently achievable across the full spectrum of expected operating conditions. The commenter said the vast majority of the opacity measurements in the data set were based on measurements taken during the melting and refining stage of production (as required under 40 CFR part 60, subpart AAa), and thus did not demonstrate that 0 percent opacity had been consistently achieved during charging or tapping, which was the established period with the greatest potential for uncaptured emissions to escape the melt shop. The commenter noted that most EAF steel mills were designed such that the primary emission controls (DEC) could not be engaged while the furnace roof was off during charging and tapping.

A commenter referenced previous rulemaking to corroborate their statements that the EPA did not consider its own historical information. One commenter referred to background documents for earlier NSPS rulings stating that in those documents, the EPA concluded that facilities utilizing DEC were likely to have a visible plume during charging and tapping and could not meet 0 percent opacity on a continuous basis. One commenter referenced the 1983 rulemaking docket stating it included only 7 hours of shop opacity data from some portion of the charging and tapping phase, and that such limited data from 4 decades ago was not representative of, or sufficient to, characterize current melt shop operations. The commenter said these previous findings by the EPA contradict the current proposal that 0 percent opacity was achievable on a continuous basis.

A commenter provided confidential summaries of long-term shop opacity data from the 13 facilities identified by the EPA as achieving the 0 percent standard, and noted that most of the opacity data was collected only during melting and refining, and not during charging and tapping. The commenter stated their summaries demonstrated that 0 percent melt shop opacity was not continuously achieved by the 13 mills cited as exemplars. The commenter noted in a reference that they would readily provide the confidential data to the EPA upon request.

A commenter stated that the current design at their facilities included DEC and a baghouse with a canopy, which under the proposed rule was considered the optimal design, yet it appeared the EPA did not include opacity data from their facilities in the limited data set. The commenter noted they fully complied with current limits in 40 CFR part 60, subparts AA, AAa, including opacity; but their facility data showed that compliance with a 0 percent opacity limit at all times per the proposed standard could not be met continuously due to the production process variability and the raw material inputs. The commenter stated it was possible for the melt shop to experience an opacity greater than 0 percent during charging and tapping when the DEC system was disengaged, and there were other sources of opacity from concurrent operations (*e.g.,* vacuum tank degasser operations, the LMF, and the Caster).

A commenter said the EPA in the proposed rule stated 0 percent opacity could be achieved utilizing a canopy over the furnace with an open roof monitor elsewhere. The commenter operated its facilities under such a configuration and did not meet 0 percent opacity on a continuous basis; thus, the EPA's data set was flawed and not representative of the steel manufacturing operation.

EPA Response: The EPA reviewed the summary data provided by the commenter, where for three facilities, the opacity summary data shown in Table 6 were provided.

TABLE 6—SMA DATA ON OPACITY FROM THREE FACILITIES

SMA facility No.	Number readings >0 percent opacity	Total number opacity readings	Percent >0 percent out of all readings	Year of data
1	3	349	0.9	2021
	0	296	None	2020
	11	294	3.7	2019
2	21	1,482	1.4	2021–2022
3	61	2,488	2.5	2021–2022

Although the commenter presented these data attempting to contradict 0 percent opacity as BSER, the data actually support the preponderance of opacity data at 0 percent, since the number of readings greater than 0 percent were low, ranging from none (*i.e.,* no readings greater than 0 percent) to a high of 3.7 percent, out of a total number of readings ranging from 300 to 2,500.

The EPA's evaluation of the degree of emission limitation achievable with the BSER is not based on an average of all facility data nor an average of the best facilities. Rather, the BSER is the *best* system of control that the EPA determines is adequately demonstrated for EAF in the industry, and the EPA's charge under CAA 111(a)(1) and (b)(1)(B) is to establish a standard of performance that reflects the degree of emission limitation achievable by application of that BSER.

The EPA EAF data, taken mostly from the 2010 CAA section 114 request, required ''an aggregate total of 180 minutes of opacity observation concurrent with PM and/or PM less than 2.5 micrometers ($PM_{2.5}$) testing of EAF primary control devices.'' The commenter stated that charging time is less than 1 minute to 3 minutes per charge, and tapping is 4 to 6 minutes, so it is not surprising that most of the time opacity was measured during melting and refining.

However, we agree with the commenter that because the current EAF NSPS rules in 40 CFR part 60, subparts AA and AAa only require opacity measurements during melting and refining, the data obtained by the EPA can be assumed to reflect only operation during melting and refining. Therefore, while we are retaining 0 percent opacity during melting and refining in the final rule as in the proposal, we are reverting back to the opacity limit of 6 percent opacity for charging and tapping as in the current rules in 40 CFR part 60, subparts AA, AAa.

Additionally, opacity testing during charging, tapping, and melting, and refining periods is required in the final rule. Opacity tests during tapping, and melting and refining periods should be able meet the minimum 6 minutes of total opacity testing required under EPA Method 9 in 24 consecutive tests for 15 seconds each. However, we are allowing a modification of EPA Method 9 for testing during charging because of the potentially shorter time period that charging occurs. In the final rule, we are allowing the EPA Method 9 testing during charging to be determined from the average of 12 consecutive observations recorded at 15-second intervals for a total of 3 minutes of opacity testing.

Comment: The commenter asserted that the EPA did not properly evaluate the cost of compliance with 0 percent opacity for a source as a result of modification.

EPA Response: The commenter was not specific as to what type of modification needed to be evaluated for its costs to comply with the proposed opacity standards. A modification that triggers applicability of an NSPS is a modification that increases emissions and meets the requirements in 40 CFR 60.14. Without knowing which type of modification is in question, it is difficult to compare the costs of compliance and address the commenter's concern. A facility may be adding another baghouse to accommodate increased production of the EAF. In this case, the modification (additional baghouse) is outside of the melt shop and, therefore, is not affected by the melt shop standard. If a facility is modifying an EAF to increase production, pursuant to 40 CFR 60.14 (e), an increase in production rate of the existing EAF is not considered a modification if that increase can be accomplished without a capital expenditure on that facility. The partial roof canopy determined to be BSER for the melt shop is a type of capture device that can be added to any melt shop. However, the final rule does not require that a partial roof canopy be installed to be in compliance with the opacity standard. Affected sources can seek other methods to achieve the melt shop opacity.

Comment: In regard to canopy hood control costs, a commenter stated the EPA did not examine advances in control technologies, process operations, design or efficiency improvements, or other systems of emission reduction, that are ''adequately demonstrated.'' Rather, the EPA looked to a decades-old BID, concluded that ''[c]anopy hoods are a common method of controlling fugitive EAF emissions,'' and assessed costs for: adding a partial roof canopy (segmented canopy hood, closed roof over furnace, open roof monitor elsewhere) to collect PM emissions that might otherwise escape through the shops to achieve complete control of melt shop fugitives.

The commenter stated the EPA did not analyze whether canopy hoods were used by the 19 facilities that recorded 0 percent opacity during performance testing or were absent from the 9 facilities that recorded the highest opacity during performance tests. The commenter claims that this information was available to the EPA in the docket for the 40 CFR part 63, subpart YYYYY NESHAP for EAF—the same docket that supplied the majority of the performance test data the EPA used in this rule. The commenter further asserted that the EPA's own review of the survey responses in the 40 CFR part 60, subpart YYYYY docket in June 2005 shows that the EPA knows that canopy hoods were used to capture fugitive emissions from 32 of the 38 EAF described in the CAA section 114 survey responses, and that the presence or absence of a partial roof canopy did not determine whether the facilities responding to the survey could achieve 0 percent opacity. Therefore, the EPA has no basis to now conclude for purposes of demonstrating achievability and cost effectiveness that the singular act of installing a partial roof canopy will ''achieve complete control of melt shop fugitives.''

A commenter stated the EPA's conclusion is also contradicted within the Agency's cost analysis. In order to estimate how much PM is emitted from a facility that emits 6 percent opacity, the EPA used the 1982 BID [*Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels in Steel Industry—Background Information for Proposed Standards. Preliminary Draft.* June 1982, Table 3–7 at 3–37; and the 1983 BID *(Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels in Steel Industry—Background Information for Proposed Standards.* (EPA–450/3–82–020a) July 1983; Table 3–7 at 3–37] to estimate that EAF emit an average of 29 lb/ton of uncontrolled PM emissions. The EPA then relied on the 1982 [and 1983] BID again to estimate that facilities emitting 6 percent opacity captured 90 percent of those emissions using a ''segmented canopy hood, closed roof over furnace, open roof monitor elsewhere.'' This is the exact fugitive emission capture technology that the EPA's Cost Analysis presumes facilities with greater than 0 percent opacity can install to achieve 0 percent opacity. In other words, the EPA's *Cost Analysis* assumes that facilities with a ''segmented canopy hood, closed roof over furnace, open roof monitor elsewhere'' are emitting 6 percent opacity and if those facilities install a ''segmented canopy hood, closed roof over furnace, open roof monitor elsewhere'' they will achieve 0 percent opacity. Commenter stated because it is arbitrary and unreasonable to assume that facilities will be able to achieve 0 percent opacity by doing nothing more than install the same systems that facilities already have installed without reaching 0 percent opacity, the EPA has failed to provide a cost estimate rationally related to reduction of opacity from 6 percent to 0 percent.

EPA Response: Canopy hoods have been in use for many years in many industries and are still in use today. The costs to install a partial roof canopy to enhance control of EAF melt shop fugitives was taken from relatively recent rulemakings (2011 through 2018 [16]) for the Ferroalloys industry, which also uses EAF. The 1984 EAF BID was used only to estimate uncontrolled EAF shop emissions in the proposal because there is no estimate available of uncontrolled emissions due to the fact that most, if not all, EAF facilities, especially those subject to the EAF NSPS subparts AA and AAa, have some type of control of shop emissions, *e.g.,* DEC systems; canopy hoods, side draft hoods, and tapping hoods; partial or total enclosures; scavenger duct systems; and building evacuation systems (72 FR 53818). Even if a total uncontrolled melt shop could be found, it is not a typical source test to measure emissions from a large opening such as a roof vent or an industrial door, nor does the EPA generally have the resources to perform such a test.

If some EAF facilities with canopy hoods are not achieving 0 percent opacity, as the commenter alleges, it is likely because both the NESHAP (40 CFR part 63, subpart YYYYY) and NSPS standards (40 CFR part 60, subparts AA, AAa) currently only require 6 percent opacity limits for EAF and AOD, and because the standard is higher, they are only being designed to meet that standard. Regardless of the fact that some EAF and AOD facilities may have been designed this way, they still can be designed or modified to achieve 100 percent capture to ensure 0 percent opacity. The fact that some hoods have not been achieving 100 percent capture at some facilities is not proof that canopy hoods cannot be used to do so for new, modified, or reconstructed sources. The commenter fails to provide a technical basis for why canopy hoods cannot be designed to achieve 0 percent melt shop opacity.

Out of 31 EAF facilities in the EPA EAF dataset with opacity data, 13 facilities achieved 0.000 percent shop opacity. Two additional facilities achieved 0.00 percent shop opacity, and another 4 facilities achieved 0.0 percent, for a total of 19 facilities able to comply with a 0 percent shop standard. Out of the total 31 facilities in the EPA EAF data, only 1 facility had shop opacity greater than 1 percent as an average of all runs in the test, with the average of all 31 facilities at 0.14 percent opacity (a value that would round down to 0 percent under the NSPS). See the ''Emissions Memorandum,'' discussed earlier in this section, for more information about these data.

The addition of a canopy hood or alteration of existing hoods to achieve slightly better capture is within reach by a facility achieving less than 1 percent opacity but greater than 0 percent. The scenario of installation of a canopy hood in the melt shop is used in the cost analysis to represent one method that is lower in cost and can be used to achieve the standard of performance if an existing source that is not currently achieving 0 percent melt shop opacity were to modify or reconstruct and become an affected facility under 40 CFR 60, subpart AAb.

Comment: A commenter stated melt shop partitions of the size necessary to meaningfully contain EAF emissions within the melt shop are not feasible in many mills given other equipment and shop design, including cranes. In particular, sizable partition walls are not feasible at many EAF steel mills because they will interfere with overhead cranes that transport scrap metal to the furnace. Similarly, transfer ladles that are carried by crane to and from the furnace for tapping molten metal would be blocked by partition walls.

The commenter said for existing facilities that may trigger an NSPS modification in the future, achieving 0 percent shop opacity would require extensive re-engineering that would be costly and introduce practical and worker safety concerns as well. For example, one [trade] association member stated that 0 percent shop opacity could only be achieved, if at all, with near total enclosure of the EAF and doubling the flow rate of the emission control system. The commenter stated that only very short (and therefore marginally effective) partition walls could be installed above the crane because of the lack of space between the crane and the roof. They also noted that such short partitions deteriorated quickly due to the heat and other elements. Thus, to increase the size and collection efficiency to meet a 0 percent opacity requirement, the facility would have to raise the roof of the structure at an undetermined cost (a cost that likely would trigger a ''major modification''), and potentially enclose the entire monovent, which would likely create worker safety and heat stress issues.

The commenter added, facilities would have to increase the number and volume of fans to the baghouse, as well as require new or additional fans in the shop and additional baghouses because the facility's current baghouses are operating at close to maximum capacity. Moreover, for servicing, cranes have to

[16] See *https://www.epa.gov/stationary-sources-air-pollution/ferromanganese-and-silicomanganese-production-national-emission* for information regarding Ferroalloys rules.

be moved to a different part of the melt shop due to the partitions being so close to the top of the cranes. To achieve compliance, existing facilities such as these also would have to enclose the large openings in the casting area to prevent winds from blowing through the shop or wall off the EAF operations. Neither option is feasible; melt shops are typically long buildings with EAF, LMS, and casting in the same structure.

EPA Response: The cost analysis for new, modified, or reconstructed EAF to achieve 0 percent opacity is based on a ''partial'' canopy hood and not ''partition walls,'' as the commenter suggests, that would interfere with overhead cranes. In regard to the comment that ''costly and impractical re-engineering to achieve 0 percent shop opacity that could only be achieved, if at all, with near total enclosure of the EAF that doubles the flow rate of the emission control system,'' there are 19 EAF facilities in the EPA EAF dataset that demonstrated with data from 2010 that they were capable of complying with a 0 percent melt shop opacity standard (which we assumed was during melting and refining) and, therefore, belie this concern. And because only 1 facility among the 31 facilities in the EPA EAF dataset had shop opacity greater than 1 percent as an average of all runs in the test, the addition of a canopy hood may be unnecessary and only alteration of the operation of existing hoods may be needed to achieve slightly better capture to achieve 0 percent melt shop opacity during melting and refining. This shows that meeting a new NSPS standard of 0 percent melt shop opacity during melting and refining is within reach by most if not all existing EAF facilities, so is even more likely achievable in any new facility.

In actuality, it is not likely that all current EAF facilities in the industry will need to comply with 40 CFR part 60, subpart AAb, which would only be applicable to new EAF facilities or, for existing facilities, if the result of any future modifications or reconstruction increased emissions and met the provisions in 40 CFR 60.14 for modifications and 40 CFR 60.15 for reconstruction, respectively.[17] Whether or not the modification or reconstruction planned at the facility would *also* trigger permitting requirements because it is a ''major'' modification under the permitting regulations is not relevant to the EPA's determination of the BSER. Moreover, the EPA does not agree that it is likely that the construction of the canopy will itself be considered a major modification that triggers permitting requirements. The issue here is whether to meet the revised limit an existing source that modifies needs to raise the roof structure to install equipment to meet the standard. The EPA response to this issue is that it is not required to raise the roof structure so as to be able to install equipment, and we have no knowledge (and the commenter has not provided information showing) that raising the melt shop roof has ever having been done to meet a lower opacity, such as 0 percent.

3. What is the rationale for the final BSER determination and what is the final standard of performance?

We established in the proposal (87 FR 29717–29718) that the use of a canopy hood above the crane rails, while not required to achieve 0 percent melt shop opacity during melting and refining, is a cost-effective method that can be used to do so, with cost effectiveness estimated at $1,700 per ton PM removed in $2022 for a medium-sized facility, annual costs of the canopy, at $1.1 million per year, and with PM reduction of 684 tpy at a medium facility achieving 0 percent melt shop opacity during melting and refining and 6 percent during charging and tapping, as compared to 6 percent opacity at all times. Analyses performed for small and large EAF melt shops produced similar cost-effectiveness values, at $1,800 per ton PM removed and $1,700 per ton PM removed, respectively. The values of $1,800 per ton or less are considered cost effective and, therefore, the use of additional canopy hoods above the crane rails is considered BSER for melt shop opacity for new EAF/AOD using this approach. (See section III.A.1.a of this preamble).

The performance data obtained by the EPA for 31 facilities show that 13 facilities achieved 0 percent opacity during melting and refining and the other 17 achieved very low values of opacity so that the overall average melt shop opacity from all 31 facilities was 0.14 percent. Therefore, considering that the costs are achievable even without the addition of a canopy hood, we conclude the 0 percent opacity is the standard of performance that reflects the degree of emission limitation achievable with application of the BSER for melting and refining.

We also concluded that full enclosure is not needed to achieve 0 percent melt shop opacity during melting and refining. The EPA acknowledges that facilities need sufficient capture ventilation to collect melt shop PM emitted as fugitives, but this does not necessarily require a fully enclosed melt shop, as seen in the data from EAF facilities in 2010 test reports obtained by the EPA where 0 percent opacity was achieved.

Because we do not have sufficient data to show that 0 percent melt shop opacity is achievable during charging and tapping to refute industry's assertion that 0 percent melt shop opacity is not achievable during charging and tapping, nor are these data likely available anywhere else, the final rule retains the current 6 percent NSPS limit for charging and tapping in 40 CFR part 60, subparts AA, AAa, and adds to the final rule for 40 CFR part 60, subpart AAb a testing requirement during these periods along with the requirement to test during melting and refining that is already required for facilities in operation on or before May 16, 2022. Note that the test method protocol for measuring opacity during charging has been modified for the final rule, as discussed in section V.B.1 of this preamble.

4. Are there any relevant energy impacts or nonair quality health and environmental impacts of the selection of the final BSER for melt shop opacity and, if so, how were the final emission limitations based on the BSER affected?

There are no relevant energy impacts or nonair quality health and significant environmental impacts of the final BSER for melt shop opacity. These issues are discussed in detail in sections V.A and V.B of this preamble. No comments were received on these issues.

C. NSPS Requirements for Opacity From Control Devices and Dust Handling for Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After May 16, 2022

We proposed to retain the BSER determinations for proper operation of control devices and proper dust handling procedures from NSPS subpart AAa in NSPS subpart AAb as well as the limitations of 3 percent and 10 percent opacity limits from control devices and dust handling, respectively. No comments were received on this subject. Similarly, we are finalizing the requirement for opacity from control devices and dust handling in NSPS subpart AAb, as proposed.

[17] Note that modifications pursuant to CAA section 111 need not be ''major'' to trigger application of the NSPS. Rather, a modification under CAA section 111(a)(4) is defined as a physical change in, or change in the method of operation of, a stationary source which results in *any* increase in emissions. See also 40 CFR 60.14.

D. Startup, Shutdown, Malfunction Requirements for Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Modified, Reconstructed, or Constructed After May 16, 2022

Consistent with *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the EPA has established standards in 40 CFR 60 subpart AAb that apply at all times. We also are finalizing in 40 CFR 60 subpart AAb specific requirements at 40 CFR 60.272b(c) that override the general provisions for SSM requirements. In finalizing the standards in this rule, the EPA has taken into account startup and shutdown periods and, for the reasons explained in section IV.D.2 of this preamble has not finalized alternate standards for those periods.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. Malfunctions, in contrast, are neither predictable nor routine. Instead, they are, by definition, sudden, infrequent, and not reasonably preventable failures of emissions control, process, or monitoring equipment (40 CFR 60.2). The EPA interprets CAA section 111 as not requiring emissions that occur during periods of malfunction to be factored into development of CAA section 111 standards. Nothing in CAA section 111 or in case law requires that the EPA consider malfunctions when determining what standards of performance reflect the degree of emission limitation achievable through ''the application of the best system of emission reduction'' that the EPA determines is adequately demonstrated. While the EPA accounts for variability in setting emissions standards, nothing in CAA section 111 requires the Agency to consider malfunctions as part of that analysis. The EPA is not required to treat a malfunction in the same manner as the type of variation in performance that occurs during routine operations of a source. A malfunction is a failure of the source to perform in a ''normal or usual manner'' and no statutory language compels the EPA to consider such events in setting CAA section 111 standards of performance. The EPA's approach to malfunctions in the analogous circumstances (setting ''achievable'' standards under CAA section 112) has been upheld as reasonable by the D.C. Circuit in *U.S. Sugar Corp.* v. *EPA,* 830 F.3d 579, 606–610 (2016).

1. What did we propose as the BSER determination and standard of performance?

Consistent with *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the EPA proposed that the PM and opacity standards in 40 CFR subpart AAb apply at all times. We also proposed in 40 CFR part 60, subpart AAb specific requirements at 40 CFR 60.272b(c) that override the general provisions exemptions during SSM periods.

2. What significant comments did we receive and what are our responses?

Comment: A commenter asserted that the EPA must provide work practice standards if the EPA removes SSM exemptions. Subjecting SSM periods to the same limit as those during normal operations was not adequately demonstrated as required per CAA section 111(a)(1) and was not provided in the docket prior to promulgation as per CAA section 307(d). The dataset of stack tests from 33 facilities did not include adequate testing to demonstrate that SSM periods consistently met the limits proposed in 40 CFR part 60, subpart AAb. These stack tests were not conducted during SSM periods, and as such could not provide a basis for concluding that emissions during shutdown and startup could comply with the proposed limits. The commenter asserts that, if the EPA cannot show that compliance with a numerical limit was adequately demonstrated during periods of SSM, and provide that data in the record, then the EPA does not have the legal authority under CAA section 111 to subject those emissions to such a standard.

EPA Response: Consistent with *Sierra Club* v. *EPA,* this action will ensure that the PM and opacity standards in EAF NSPS 40 CFR 60, subpart AAb apply at all times, including during periods of startup and shutdown. Because *Sierra Club* v. *EPA* established that emissions standards or limitations must be continuous in nature, the EPA must determine what standard will apply during periods of SSM. Moreover, CAA section 111(h)(1) provides that the EPA may only provide for work practice standards when the Administrator determines that it is not feasible to prescribe or enforce a numerical work practice standard. We have determined that the numerical standards in EAF NSPS 40 CFR 60 subpart AAb are appropriate as EAF and AOD facilities can comply with the standards during startup and shutdown because the control devices are the same during startup and shutdown as in normal operation and would provide the same protection to PM emissions, both for PM from the control devices as well as opacity from melt shop, control devices, and dust handling. In regard to the 0 percent melt shop opacity standard, this standard in 40 CFR part 60, subpart AAb only applies during melting and refining; startup or shutdown does not fall under the operational description of melting and refining. A opacity standard of 6 percent would apply at all other times.

While commenters argue that the EPA must provide work practice standards, the commenters have not provided information showing that compliance with the numerical emission limitations is not possible during startup and shutdown events and that, therefore, the EPA's determination to apply the PM and opacity standards at all times would be inappropriate. In addition to the standards applying at all times, sources will need to comply with the CAA section 111 general provisions, which include ''general duty'' requirements in 40 CFR 60.11(d) to operate ''in a manner consistent with good air pollution control practice for minimizing emissions.'' These provisions apply at all times, including during startup and shutdown, as well as during malfunctions.

Comment: A commenter stated if a 0 percent opacity standard for melt shop emissions at all times was implemented, the EPA must exclude periods of malfunctions and upset conditions. The commenter explained that malfunctions have occurred during the melting and casting operations that required extraordinary measures for corrective action, such as a ''breakout.'' In an extremely dangerous situation, breakouts occurred when molten steel escaped from one or more mold strands at the caster or during casting. The commenter stated after a breakout and subsequent corrective action, emissions were generated and may exit the melt shop, and those emissions should not be considered in determining compliance with the 0 percent opacity melt shop requirement. The commenter said the EPA's proposed approach lacked an understanding of the significant dangers, risks, and related emissions associated with ''breakouts'' and other malfunction events that occur during the steelmaking processes, and the EPA should reconsider the 0 percent melt shop opacity standard.

EPA Response: The EPA disagrees with the commenter that emissions during a malfunction are not appropriately subject to the standard. Malfunctions that cause exceedances of any part of a rule are considered a violation under the NSPS and are a compliance issue that is relegated to the EPA's enforcement office. Facilities should document the circumstances of the malfunction so as to be able to discuss the special circumstances of the event with the EPA's enforcement officer. It is not the purpose of the BSER to take into account unpredictable, sudden, infrequent events such as what is described by the commenter. We also note that casting is not part of the EAF NSPS source category.

E. Testing and Monitoring Requirements for Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels

1. What did we propose for testing and monitoring?

From the EPA review of the current NSPS's testing and monitoring requirements in 40 CFR part 60, subpart AAa, we evaluated and determined the testing, monitoring, recordkeeping and reporting requirements needed to be clarified and revised'' to ensure compliance with the emission standards, considering that the NSPS reflect BSER under conditions of proper operation and maintenance. Consequently, we proposed changes to testing and monitoring in 40 CFR part 60, subparts AA and AAa, and also incorporated some of these requirements along with additional requirements into new 40 CFR part 60, subpart AAb.

Specifically, we proposed amendments to clarify, correct, or refine the rule requirements to enhance compliance and enforcement with 40 CFR part 60, sections 60.271 and 60.271a ''Definitions'', 60.272 and 60.272a ''Standard for particulate matter'', 60.273 and 60.273a ''Emission monitoring'', 60.274a ''Monitoring of operations'', 60.275a ''Test methods and procedures'', and 60.276a ''Recordkeeping and reporting requirements.''

In addition, we proposed that sources complying with 40 CFR part 60, subpart AAb would be required to perform compliance testing every 5 years after the initial testing performed upon startup, as required under 40 CFR 60.8. This requirement for periodic testing already is required in many of the permits for existing EAF in both the EPA's EAF dataset and in the industry, and is a standard requirement for testing of other sources of PM emissions in many other industrial sectors.

We also solicited in the proposal for comments or data and other relevant information on whether the EPA should change the allotted time to both find and fix the cause of a BLDS alarm from 3 hours to a longer timeframe (*e.g.,* 24 hours as in other rules), or some other duration.

2. What significant comments did we receive on testing and monitoring and what are our responses?

Comment: The commenter said facilities should be allowed 24 hours to respond to BLDS alarms and to complete the response as soon as practical in 40 CFR part 60, subparts AA, AAa, and AAb. The commenter disagreed with the proposed 40 CFR part 60, subpart AAb provisions that would require facilities to determine the cause of all BLDS alarms within 1 hour and alleviate the cause of the alarm within 3 hours by taking the necessary response action. The commenter recommended the EPA adopt a 24-hour timeframe to initiate corrective action and to require that response actions be completed as soon as practicable. This approach would recognize the practical realities in identifying and responding to BLDS alarms. The commenter added that this approach is the same as that used in the Integrated Iron and Steel NESHAP, and is consistent with 40 CFR part 63, subparts X (NESHAP for Secondary Lead Smelting), DDD (NESHAP for Mineral Wool Production), EEE (NESHAP from Hazardous Waste Combustors), MMM (NESHAP for Pesticide Active Ingredient Production), RRR (NESHAP for Secondary Aluminum Production), and TTT (NESHAP for Primary Lead Smelting). The commenter said there was no justification for the proposal to be different from other existing rules. The commenter added that the proposed 3-hour time period was arbitrary and ignored the numerous scenarios in which it can take longer than 3 hours to identify and fix the cause of an alarm. Allowing facilities 24 hours to identify the cause and requiring facilities to alleviate the cause of the alarm ''as soon as practicable'' is more practical, particularly where many baghouse compartments must be inspected to determine the cause of an alarm.

The commenter noted that there are situations in which more than 3 hours is needed to respond to a BLDS alarm and address its cause. Because many mills calibrate their BLDS to be very sensitive, the likelihood that a BLDS alarm will be falsely triggered is increased. The commenter included the following examples of situations in which false alarms can occur:

- *Weather.* BLDS alarms will occasionally trigger during a heavy downpour or when there are significant changes in temperature or humidity.
- *Bag Cleaning Cycle.* BLDS alarm may trigger at the end of the baghouse cleaning cycle due to the temporary absence of dust in the bags.
- *New Bag Start.* BLDS alarms can be triggered following a replacement of some or all of the bags in the baghouse.
- *Systems Checks/Testing.* Some facilities may run systems checks on their BLDS that cause the system to alarm. For example, a facility may check the sensitivity of a BLDS by introducing a handful of flour into a port upstream from the probe. Facilities also evaluate and optimize their BLDS performance through drift checks, response tests, calibration exercises, and other quality assurance procedures. Some of these procedures require the alarm to be triggered in order to test performance, but in other instances the BLDS alarm may be inadvertently triggered during testing.
- *Electrical Malfunctions.* As BLDS detection is based on contact electrification, alarms can be triggered due to electrical surges impacting the sensors, processing electronics, or the connections between the sensor and processing electronics. These surges can either be environmental (lightning) or from variations/malfunctions in the BLDS system, its software, or its power source. Additionally, the abrasive environment in the baghouse duct can deteriorate the BLDS probe, probe housing, and housing insulation, which can cause an increase in malfunctions. BLDS alarms may be triggered during temporary power lapses or brief connectivity issues between the sensor and the processing electrics, or between the processing electronics and the system output/alarm. The BLDS can experience brief mechanical or software glitches/errors, including with respect to the sensor's signal amplification or with the configuration of the processing electronics.
- *Repair/Maintenance.* Some baghouse repair and maintenance activities may be conducted while the baghouse is in operation. In some of these cases, proper inspection and repair requires the baghouse to be operating in order to observe and repair malfunctions/maintenance issues. Often these activities are coordinated with a baghouse operator observing the BLDS readout in real time in order to identify the cause of an earlier alarm or to proactively identify maintenance or performance issues. Baghouse repair and maintenance activities sometimes must be conducted when the baghouse is operating because the repair/maintenance is urgently needed, and it is infeasible to quickly shut down the baghouse. These activities will cause BLDS alarms to trigger. Work on baghouse compartments and conveyances can introduce particulates into the system or dislodge caked or

accumulated dust which triggers alarms. Sounding of BLDS alarms also can be caused by maintenance and repair activities conducted when the baghouse is not operating. These activities can introduce foreign material or dislodge accumulations of material from ducts, conveyances, access panels, joints, and other components of the system upstream from the probe. Then when the baghouse is restarted, the newly introduced or dislodged material can cause the BLDS alarm to be triggered.

The commenter pointed out that it is possible for a baghouse to operate within its emission and opacity limits even if the cause of a BLDS alarm is not identified and corrective measures taken. For example, if a broken bag in a compartment causes an alarm, the compartment can be isolated and shut down without affecting the rest of the baghouse. The commenter noted that determining the cause of the alarm often requires operators to undertake a multi-step troubleshooting process of elimination requiring multiple rounds of physical inspections and diagnostic efforts. This process of elimination often requires more than 3 hours to complete. The process can be very time-consuming, particularly when the BLDS alarm lasts only a short time. Identifying the cause of a brief BLDS alarm, the commenter said, can be very difficult and sometimes proves impossible. Some baghouses in the EAF industry have 25 or more compartments housing 5,000 or more individual bags. Some mills do not have BLDS with detection capability in each separate compartment because the baghouse design does not allow for such monitoring (*e.g.,* multiple compartments sharing common exit plenum). In these instances, mills must continue running and sequentially isolate compartments to determine which compartment may have caused the BLDS alarm. Facilities must then physically examine the compartment(s), which may contain 150 or more individual bags. If a bag has a significant rupture or has been dislodged, the cause of the alarm will likely be readily apparent. However, some alarms can be triggered by extremely small holes in bags and, in these cases, finding the leak by physical inspection can take a long time.

The commenter said that EAF mills can have difficulty responding to multiple, intermittent alarms of short duration. The commenter noted that EAF facilities record the alarm as resolved where investigation shows no evidence of a bag leak. While the facility may be able to respond to each separate alarm in under 3 hours, the commenter said they are aware of one instance in which an enforcement authority determined the company was in violation of the 3-hour response requirement because the total time the facility spent responding to each of the separate intermittent alarms exceeded 3 hours. The commenter said the enforcement authority misinterpreted the 3-hour response requirement. This example was provided to show how a 3-hour response requirement presents a compliance risk even when individual responses are completed within the 3-hour window. The commenter recommended the following additions be made to 40 CFR 60.273(f) in all three rules in regard to the leak monitors to clarify false alarm situations.

The commenter recommended adding to the requirements in 40 CFR 60.273(f)), 60.273a(f)), and 60.273b(f)) that begin with: ''Establishing to the extent acceptable by the delegated authority that the alarm was a false alarm and not caused by a bag leak or other malfunction that could reasonably result in excess PM emissions,'' the phrase ''in which case alarms due to the monitor malfunctioning are not subject to the [24-hour] response action requirement, as long as the [leak] monitor malfunction is timely corrected.''

The commenter recommended adding to the requirements in 40 CFR 60.273(f)), 60.273a(f)), and 60.273b(f)) that begin with: ''Shutting down the process producing the PM emissions,'' the phrase ''provided that shutting down the process unit is not required if an operator reasonably believes repetitive alarms are the result of a [leak] monitor malfunction, and the monitor malfunction is timely repaired.''

EPA Response: We appreciate the details provided by the commenters to explain the reasons why a 24-hour response to BLDS alarms is warranted based on technical issues that EAF facility operators face and also why a 24-hour response is justified based on other similar rules that allow a 24-hour response. In light of the rationale provided, we are including the 24-hour response in the revisions to 40 CFR part 60, subparts AA, AAa, and AAb, effective upon promulgation.

In regard to the specific language the commenter suggests including in the rules in 40 CFR 60.273(f)), 60.273a(f)), and 60.273b(f)), the list of potential response actions are not to be taken as exclusive, *i.e.,* the responses listed have the caveat that ''response actions may include, but are not limited to, the following, etc.'' The commenter's suggested changes for 40 CFR 60.273(f) in all 3 rules are redundant within the existing and proposed rules because the phrase ''not caused by . . . . . other malfunction that could reasonably result in excess PM emissions'' already covers leak monitor malfunction. This is the same issue for 40 CFR 60.273(f) in all 3 rules, where a shutdown is just one option for a response action and not a required action. In all 3 rules in 40 CFR 60.273(f), fixing the leak monitor is the appropriate response action if that is determined to be the cause of the alarm. However, along with changing the response time to 24 hours, we have added a specific item in all three EAF rules in 40 CFR 60.273(f) to make it clear that leak monitor malfunction could be the cause, as follows: ''Establishing to the extent acceptable by the delegated authority that the alarm was a false alarm caused by a malfunctioning monitor and not caused by excess PM emissions.''

Comment: A commenter asserted that the current compliance demonstration requirements using the fan amperage and damper position monitoring in 40 CFR part 60, subparts AA, AAa are the best methods for assuring compliance with the melt shop NSPS standards. A commenter asserted that the existing fan amperage and damper position monitoring in combination with opacity observations are the best methods of assuring compliance with the NSPS standards for the melt shop. The commenter opposed the proposed new monitoring requirements for 40 CFR part 60, subparts AA and AAa that included:

- Installation of BLDS on all baghouses, including multi-stack baghouses;
- Monitoring and operational restriction for furnace static pressure monitoring based on 15-minute averages on all EAF;
- Monitoring and operational restriction for volumetric flow rate or static pressure at each separately-ducted hood, based on 15-minute averages on all EAF;
- Removal of the option for monitoring and operational restriction for fan amps;
- Adding inspections and maintenance requirements for holes or other openings in the melt shop building; and
- Mandate for shop opacity observations to be made during charging and tapping or during the period of the heat cycle that generates the greatest uncaptured emissions.

The commenter considered these new monitoring requirements to be unnecessary, expensive, and, in some cases, impractical. The commenter said the existing monitoring requirements in 40 CFR part 60, subparts AA and AAa are adequate for demonstrating compliance with the standards. The commenter stated that the existing fan amperage and damper position monitoring have worked efficiently and effectively for many years and the proposed new monitoring would be less effective and would impose ''. . . extreme technical and engineering complications'' on EAF plants.

Similarly, the commenter urged the EPA to keep the current requirement in 40 CFR part 60, subparts AA, AAa for monitoring fan amperage in place, because they said this parameter directly correlates to the air flow to the control device, via the fan curve, unique to each site.

EPA Response: The responses to BLDS monitoring requirements, damper position, fan amperage, furnace static pressure, melt shop inspection, melt shop opacity, and volumetric flow and static pressure follow here.

• *BLDS Response.* We proposed the BLDS monitoring requirement for all baghouses in 40 CFR part 60, subparts AA, AAa, and AAb because BLDS provides better information about EAF baghouse operation and compliance assurance for the PM emission and stack opacity limits than what is currently required in 40 CFR part 60, subparts AA and AAa, and because BLDS monitoring at all baghouses is technically feasible. Currently, as an alternative to COMs, single-stack baghouses are required to install a BLDS and perform EPA Method 9 visible emissions at the stack, whereas modular, multi-stack, negative-pressure or positive-pressure fabric filters are only required to conduct EPA Method 9 visible emissions monitoring. We agree with the commenter that the proposed change to require all types of baghouses to have BLDS should not be made as a correction in 40 CFR part 60, subparts AA and AAa, nor included in 40 CFR part 60, subpart AAb for all types of baghouses. Therefore, because using BLDS at all baghouses would involve the purchase of equipment not currently installed at facilities not using single-stack baghouses, this requirement is not included in the final rules for 40 CFR part 60, subparts AA and AAa. For 40 CFR part 60, subpart AAb, because for existing facilities that modify or reconstruct, requiring BLDS at baghouses other than those with single stacks would involve the purchase of equipment not currently installed at these facilities, the BLDS requirement is included in the final rule for 40 CFR part 60, subpart AAb only for single stack baghouses. For new sources, the BLDS requirement is included in the final rule for 40 CFR part 60, subpart AAb, only for single stack baghouses because using BLDS on multi-stack baghouses is not demonstrated in the EAF industry due to the high capital cost. Multi-stack baghouses in the EAF industry have vents rather than stacks, are operated at positive pressure, and not amenable to leak detection systems.

• *Damper Position Response.* We proposed changes to the monitoring frequency of damper position in 40 CFR part 60, subparts AA and AAa, and included these proposed changes in 40 CFR part 60, subpart AAb, because of the variability of this parameter during a furnace cycle. As damper position is expected to change during the heat cycle, a once-per-shift monitoring and recordkeeping event fails to provide both the facility and regulatory agencies with the ability to determine if the emissions capture system is being properly operated. Damper position records are intended to be used as a way to evaluate how the total flow (using amperage as surrogate for flow) is partitioned between the separately ducted hoods. Therefore, increasing the recording of damper position provides a more accurate assessment of the capture system throughout a heat cycle. Facilities are already required to record all damper positions during performance testing to demonstrate compliance pursuant to 40 CFR 60.274(c) and 60.274a(c). We disagree with the commenter that this change should not be made as a correction. Therefore, for the reasons explained at proposal, the final rules for 40 CFR part 60, subparts AA, AAa, and AAb include the requirement for damper position recording and frequency during operation in a manner and frequency consistent with damper position records during the initial or most recent performance test demonstrating compliance with applicable PM standards; and for 40 CFR part 60, subpart AAb, only if damper position data were recorded throughout a complete heat cycle. See 40 CFR 60.274(c)(1) and (i)(5), 60. 274a(c)(1) and (h)(5), and 60.274b(c)(1) and (h)(5). Compliance with this clarified aspect of the rule is required 180 days from the effective date of the final rule amendments for facilities complying with 40 CFR part 60, subparts AA and AAa, the same as the requirement for electronic reporting; and no later than the effective date of the final rule or upon startup, whichever is later, for facilities subject to 40 CFR part 60, subpart AAb.

• *Fan Amperage Response.* The EPA proposed deleting the monitoring of fan amps on a once-per-shift basis as a surrogate for volumetric flow from at 40 CFR 60.274(b)/60.274a(b) for 40 CFR part 60, subparts AA and AAa due to the increased use of variable speed fans in the industry. Based on comments provided in response to the proposed change, the EPA agrees with the commenter that fan amperage monitoring should be able to be used as a surrogate for volumetric flow. However, the EPA believes this surrogate can only be allowed under some conditions. To maintain consistency with the original intent of the requirement to record fan amperage in 40 CFR part 60, subpart AAa, in the final rules for 40 CFR part 60, subparts AA, AAa, and AAb, fan amperage monitoring can be used as a surrogate for volumetric flow when recorded on a more frequent basis than once-per-shift. The EPA is promulgating for 40 CFR part 60, subparts AA, AAa, and AAb, the requirement for monitoring and recording of fan amperage as frequently as damper position measurement, *i.e.,* in a manner and frequency consistent with damper position records during the initial or most recent performance test demonstrating compliance with applicable PM standards so that the amperage data provide information that is proportional to volumetric flow in 40 CFR 60.274(c))1) and (i)(5); 60.274(c)(1) and (h)(5); and 60.274b(c)(1)(h)(5). Compliance with this clarified aspect of the rule is required 180 days from the effective date of the final rule amendments for facilities complying with 40 CFR part 60, subparts AA and AAa, the same as the requirement for electronic reporting and no later than the effective date of the final rule or upon startup, whichever is later, for facilities subject to 40 CFR part 60, subpart AAb.

• *Furnace Static Pressure Response.* We proposed the requirement for monitoring and operational restriction for furnace static pressure monitoring for 40 CFR part 60, subparts AA, AAa, and AAb based on 15-minute averages on all EAF because it provides better information about emissions capture at the EAF and compliance assurance with melt shop opacity requirements at 40 CFR 60.272(a)(3), 60.272a(a)(3), and 40 CFR 60.272b(a)(3) than what is currently required in 40 CFR part 60, subparts AA and AAa. Currently, a furnace static pressure monitoring device is not required if the facility conducts daily shop opacity readings. If a facility elects to use furnace static pressure monitoring for compliance, furnace static pressure is only monitored once per shift in 40 CFR part 60, subparts AA and AAa (see 40 CFR 60.273(d)/60.273a(d) and 40 CFR 60.273(d)/60.274a(b)). The EPA proposed requiring continuous monitoring of furnace static pressure because it would provide information about capture at the EAF on a more frequent basis and because many facilities already use this equipment. Because using this monitoring method/compliance option would involve the purchase of equipment not currently available or installed at all subject facilities, we agree with the commenter that this change should not be made as a correction nor included in 40 CFR part 60, subparts AA, AAa, and AAb. Therefore, this requirement for 40 CFR part 60, subparts AA, AAa, and AAb is not included in the final rules.

In response to comments regarding proposed averaging periods of 15 minutes for furnace static pressure, the EPA has modified the averaging period language in the final rule for 40 CFR part 60, subparts AA, AAa, and AAb (40 CFR 60.274(f), 60.274a(f), and 60.274b(f)) to be ''no greater than 15 minutes.'' This modification allows greater flexibility for establishing monitoring setpoints to capture the variability during short periods that are much less than 15 minutes.

• *Melt Shop Inspection Response.* We proposed a clarification that the melt shop be inspected for holes or other openings that would allow particulate matter to escape for 40 CFR part 60, subparts AA, AAa, and included in 40 CFR part 60, AAb, because this procedure provides compliance assurance with melt shop opacity requirements, and is better than what is currently required at 40 CFR 60.272(a)(3)/60.272a(a)(3). Currently, inspections are required for equipment important to the performance of the capture system at 40 CFR 60.274(e)/ 60.274a(d), which specifies that inspections must include observations of physical appearance of the equipment. We disagree with the commenter that changes to 40 CFR part 60, subparts AA and AAa, should not be made as a correction because we understand that the melt shop building itself acts as a portion of the capture system particularly during charging and tapping. Since this inspection would not involve the purchase of equipment not currently available or installed at the facility and arguably is already addressed under the current requirement for inspections, the clarification that inspection for holes or other openings in the melt shop building is part of the capture system inspection is included in the final rules for 40 CFR part 60, subparts AA, AAa, and AAb. Compliance with this clarified aspect of the rule is required 180 days from the effective date of the final rule amendments for facilities complying with 40 CFR part 60, subparts AA and AAa, the same as the requirement for electronic reporting and no later than the effective date of the final rule or upon startup, whichever is later, for facilities subject to 40 CFR part 60, subpart AAb.

• *Melt Shop Opacity Response.* We proposed the clarification that melt shop opacity observations for 40 CFR part 60, subparts AA and AAa must be made during charging and tapping or during the period of the heat cycle that generates the greatest uncaptured emissions for 40 CFR part 60, subparts AA and AAa because this requirement provides better information about EAF and AOD capture system performance and compliance assurance with melt shop opacity requirements at 40 CFR 60.272(a)(3)/60.272a(a)(3) beyond what is currently required. The NSPS at 40 CFR part 60, subpart AA has a 6 percent opacity limit at the melt shop except for during periods of charging and tapping, for which 20 percent and 40 percent are allowed, respectively (see 40 CFR 60.272(a)(3)). When 40 CFR part 60, subpart AAa was promulgated in 1984, the exceptions for periods of charging and tapping were removed, and, instead, the opacity limit for the EAF melt shop was set at 6 percent at all times (see 40 CFR 60.272a(a)(3)). In 40 CFR part 60, subpart AA, the EPA had allowed a higher opacity limit during charging and tapping because those periods had greater potential for uncaptured emissions than during melting and refining. Therefore, we agree with the commenter that the clarification in the proposal that opacity should be tested at the site with the greatest uncaptured emissions should not be made for 40 CFR part 60, subpart AA. However, we disagree with the commenter that the changes to 40 CFR part 60, subpart AAa should not be made as clarifications or corrections because the proposed rule edits clarify that the 6 percent opacity applies at all times in all locations of the melt shop, as explained below. In 40 CFR part 60, subpart, AAa, it was required that sources constructed, modified, or reconstructed after 1983 achieve a greater level of capture performance during charging and tapping than previously required, and the exceptions during charging and tapping that were in 40 CFR part 60, subpart AA were removed. Therefore, the EPA is including in the final rule for 40 CFR part 60, subpart AAa the proposed clarification to the opacity testing option in 40 CFR 60.273a(d)(2), when a facility chooses to forgo using a furnace static pressure monitoring device on an EAF equipped with a DEC system, to test opacity no less than once per week from the tap of one EAF heat cycle to the tap of the following heat cycle. This clarification along with the test method and procedure requirements in 40 CFR 60.275a(e), make it clear that the facility is required to demonstrate compliance with melt shop opacity at all times, including the period of the furnace cycle that provides the greatest challenge to the capture system, which was originally intended when creating 40 CFR part 60, subpart AAa. In addition, the proposed clarification in 40 CFR 60.272a(a)(3) is being finalized in this rulemaking for 40 CFR part 60, subpart AAa, that where it is possible to determine that a number of visible emission sites relate to only 1 incident of visible emissions, only 1 observation of shop opacity is required, at the site of highest opacity that directly relates to the cause (or location) of visible emissions observed during the single incident. The comments concerning the requirement in the proposed changes to 40 CFR part 60, subpart AAb, for shop opacity observations to be made during charging and tapping or during the period of the heat cycle that generates the greatest uncaptured emissions, are no longer relevant due to changes made to the proposed 40 CFR part 60, subpart AAb for the final rule, to allow 6 percent opacity during charging and tapping and to require testing during all phases of operation, *i.e.,* melting and refining, charging, and tapping, Because monitoring opacity is already required in 40 CFR part 60, subpart AAa in the various parts of the rule discussed in the preceding paragraphs, the clarifications of measuring melt shop opacity do not involve the purchase of equipment not currently used at the facility and, therefore, are included in this final rule. Compliance with these rule clarifications of 40 CFR part 60, subpart AAa are required 180 days from the effective date of the final rule amendments, the same as the requirement for electronic reporting.

• *Volumetric Flow and Static Pressure Response.* We proposed the requirement to continuously monitor and have operational restrictions for either volumetric flow rate or static pressure at each separately ducted hood for 40 CFR part 60, subpart AA, AAa, and AAb because it provides better information about emissions capture at the EAF and AOD and compliance assurance with melt shop opacity requirements at 40 CFR 60.272(a)(3), 60.272a(a)(3), and 60.272b(a)(3) than what is currently required in 40 CFR part 60, subparts AA and AAa. In 40 CFR part 60, subpart AA, AAa, and AAb, there are multiple options for monitoring operations at a facility (40 CFR 60.274(b),60.274a(b), and 60.274b(b)), which may include monitoring of volumetric flow and static pressure at each separately ducted hood. Continuous monitoring of volumetric flow rate or static pressure at each separately ducted hood would provide better information about capture at each separately ducted hood and a more direct measure of capture at each separately ducted hood. However, we agree with the commenter that this change should not be made as a correction because using this monitoring method/compliance option would involve the purchase of equipment not currently available or installed at facilities. Therefore, this requirement is not included in the final rule for 40 CFR part 60, subparts AA, AAa, and AAb.

Comment: A commenter asserted that the CAA limits the EPA's NSPS revision authority to only new sources. Commenter stated there is no denying that the proposed monitoring and associated revisions to 40 CFR part 60, subpart AA and AAa are materially substantive and are not error corrections, clarifications, or clerical adjustments. These changes far exceed the EPA's legal authority to revise a NSPS applicable to existing sources. The commenter continued, the EPA's legal authority under the CAA is very limited as it relates to revisions to existing NSPSs. The 40 CFR part 60, subpart AA and AAa proposed revisions (BLDS, furnace static pressure monitoring, volumetric flow monitoring, etc.) all constitute an "emission limitation" as defined by the CAA and, therefore, constitute a "standard of performance." The EPA has no authority under the CAA to make any such revisions to a "standard of performance" unless those revisions are expressly applicable to "new sources." The commenter said the proposed changes to the melt shop monitoring requirements were arbitrary and violate the basic premise of NSPS that revisions apply only to facilities that qualify as new, modified, or reconstructed after proposal of the NSPS requirements.

The commenter also said the EPA does not have the authority to add new monitoring requirements for charging and tapping operations. The existing shop opacity monitoring in 40 CFR part 60, subpart AAa verifies efficiency of the DEC during normal operations. By expanding monitoring requirements to cover tapping and charging (a time period the furnace roof is rolled back, and the DEC control is not engaged), the EPA was creating new monitoring requirements designed to monitor a standard that was not included in the original rule. The proposed monitoring during charging and tapping cannot evaluate DEC capture efficiency, as the shop opacity observations were originally designed to do. Hence, the addition of the new monitoring, the commenter said, represents an unlawful revision to the existing NSPS standard.

The commenter was concerned the EPA was adding entirely new installation, monitoring, and maintenance requirement for charging and tapping furnace modes, including requirements for operators to install, calibrate, and maintain monitoring devices that continuously record the capture system damper position(s) and either the volumetric flow rate through each separately ducted hood or the rolling 15-minute average static pressure at each separately ducted hood. The commenter said these requirements are unnecessary and that they ignore the 1999 rulemaking that provided alternative monitoring methods. The commenter also argued the EPA failed to provide a reasonable explanation for these changes, had not explained why the additional monitoring is needed, had not explained the EPA's change in position from prior EAF steel NSPS rulemakings, and had neglected to account for any costs associated with the monitoring requirements.

EPA Response: General Monitoring Response: We proposed various monitoring changes in 40 CFR part 60, subparts AA and AAa for purposes of providing better information about EAF baghouse operation and compliance assurance for the PM emission limit at 40 CFR 60.272(a)(1)/60.272a(a)(1), and EAF capture system performance and compliance assurance with melt shop opacity requirements at 40 CFR 60.272(a)(3) and 60.272a(a)(3) than what is currently required.

We learned through public comments that some of the monitoring changes would require significant capital investment through equipment purchases; therefore, the changes requiring purchases of equipment are not included in the final rule for 40 CFR part 60, subparts AA and AAa. The requirements that we are finalizing do not make the standards more stringent; therefore, these changes do not implicate the commenter's concern that we have improperly revised the NSPS applicable to existing sources. For these other monitoring changes that are included in the final rule, either as proposed or with modification of proposed requirement, the compliance date is 180 days from the effective date of the final rule amendments for facilities complying with 40 CFR part 60, subparts AA and AAa, which is the same as the requirement for electronic reporting. This time period is to allow facilities to prepare for any changes to reporting and recordkeeping.

The 4 proposed monitoring requirements that are not included in the final rule are for BLDS for multi-stack baghouses for 40 CFR part 60, subparts AA, AAa, and AAb; melt shop opacity for 40 CFR part 60, subpart AA only; furnace static pressure monitoring and operation for 40 CFR part 60, subparts AA, AAa, and AAb; and volumetric flow and static pressure monitoring and operation for 40 CFR part 60, subparts AA, AAa, and AAb. The 2 proposed monitoring requirements that have been retained in the final rule, as proposed, are melt shop inspection (for 40 CFR part 60, subparts AA, AAa, and AAb) and melt shop opacity (for 40 CFR part 60, subparts AAa and AAb). The 2 proposed monitoring requirements that have been retained with modification are for damper position and for fan amperage (for 40 CFR part 60, subparts AA, AAa, and AAb), where we are finalizing the requirement for facilities to record damper positions and fan amperage in a manner and frequency consistent with records made during the initial or most recent performance test demonstrating compliance with applicable PM standards. For additional explanation and rationale behind the 7 proposed requirements and their disposition in the final rule, refer to the discussions in this preamble under the following section headings (listed alphabetically): BLDS Response; Damper Position Response; Fan Amperage Response; Furnace Static Pressure Response; Melt Shop Inspection Response; Melt Shop Opacity Response; and Volumetric Flow and Static Pressure Response.

Comment: A commenter asserted that the current compliance demonstration requirements using the fan amperage and damper position monitoring in 40 CFR part 60, subparts AA, AAa are the best methods for assuring compliance with the melt shop NSPS standards and, therefore, the commenter opposes the proposed new monitoring requirements for 40 CFR part 60 subpart AAb.

The commenter opposed the following proposed new monitoring requirements for 40 CFR part 60 subpart AAb:

- Installation of bag leak detection monitoring systems on all baghouses, including multi-stack baghouses;
- Monitoring and operational restriction for furnace static pressure

monitoring based on 15-minute averages on all EAF;

- Monitoring and operational restriction for volumetric flow rate or static pressure at each separately-ducted hood, based on 15-minute averages on all EAF;
- Removal of the option for monitoring and operational restriction for fan amps;
- Adding inspections and maintenance requirements for holes or other openings in the melt shop building; and
- Mandate for shop opacity observations to be made during charging and tapping or during the period of the heat cycle that generates the greatest uncaptured emissions.

The commenter considered these new monitoring requirements to be unnecessary, expensive, and, some cases, impractical. The commenter said the existing monitoring requirements (in 40 CFR part 60, subparts AA and AAa) are adequate for demonstrating compliance with the standards. The commenter stated that the existing fan amperage and damper position monitoring have worked efficiently and effectively for many years and the proposed new monitoring would be less effective and would impose extreme technical and engineering complications on EAF plants. Similarly, a commenter urged the EPA to keep the current requirement for monitoring fan amperage in place, because they said this parameter directly correlates to the air flow to the control device, via the fan curve, which is unique to each site.

A commenter stated the EPA should clarify how the proposed new monitoring requirements improve compliance demonstration. The commenter said it was unclear how the additional monitoring requirements in the proposed [40 CFR part 60,subpart AAb] rule will improve data or accuracy in demonstrating compliance with applicable requirements. The proposed NSPS 40 CFR part 60, subpart AAb requires monitoring of parameters that are not required to be monitored under the existing NSPS 40 CFR part 60, subparts AA and AAa standards. The commenter recommended the EPA explain the benefits of new monitoring techniques and additional monitoring parameters. The monitoring requirements should provide enough data to accurately demonstrate compliance with applicable requirements. The commenter added that the EPA must consider the cost to air agencies and facilities and associated benefits to compliance before requiring additional monitoring. Additional monitoring with no clear benefit is burdensome for both regulated facilities and delegated authorities due to additional equipment, maintenance, and operator costs.

EPA Response: We considered the comments submitted by the commenter and have modified the final rule for 40 CFR part 60, subpart AAb for certain proposed requirements to reflect this and other comments received, and removed other requirements entirely. We included some monitoring requirements in the final rules, as proposed. Our response to each issue listed by the commenter are described in this section in the EPA responses to the comments, as follows: BLDS Response; Damper Position Response; Fan Amperage Response; Furnace Static Pressure Response; Melt Shop Inspection Response (as well as the EPA's response to the proposed requirements in 40 CFR 60.274b(d) for 40 CFR part 60, subpart AAb in regard to allowing operators discretion in an inspection as to what issues ''materially impact'' the capture system performance); Melt Shop Opacity Response; Volumetric Flow and Static Pressure Response; and General Monitoring Response.

The comment concerning a proposed requirement in 40 CFR part 60, subpart AAb for shop opacity observations to be made during charging and tapping or during the period of the heat cycle that generates the greatest uncaptured emissions is no longer relevant due to changes made to the proposed 40 CFR part 60, subpart AAb for the final rule, to allow 6 percent opacity during charging and tapping and to require testing during all phases of operation, *i.e.,* melting and refining, charging, and tapping.

Comment: A commenter asserted that the EPA should define the term ''material impact'' (40 CFR 60.274e, 60.274a(d), and 60.274b(d)) in terms of opacity limits and only require repairs when holes result in noncompliance with the opacity standards.

A commenter recommended the EPA better define a ''material impact'' on the capture system because they said the phrase was too vague. Any airflow changes, they said, may theoretically impact capture efficiency to some extent, but fluctuations that do not affect the compliance of the facility with the substantive emission and opacity standards should not be prohibited. The EPA should define material impacts in terms of opacity limits by revising 40 CFR part 60, subparts AA, AAa, and AAb to only require repairs to openings that lead to noncompliance with the opacity standards.

EPA Response: The Melt Shop Inspection Response earlier in this section provides part of the EPA response to this comment concerning proposed requirements for 40 CFR part 60, subpart AAb (40 CFR 60.274b(d)), which is the same as the EPA response for the proposed clarifications in 40 CFR part 60, subparts AA and AAa (40 CFR 60.274(e) and 60.274a(d)) and explains why we disagree with the commenter and are including the requirement to inspect for holes or other openings in the melt shop in the final rules to ensure compliance with the opacity standards in 40 CFR part 60, subparts AA, AAa, and AAb.

In addition, for 40 CFR part 60, subpart AAb, we proposed the requirement for monthly inspections to include the language to address issues that are ''determined by the operator to materially impact the efficacy of the capture system'' in 40 CFR 60.274b(d). This allows for a determination by the operator as to whether an identified issue is to be considered a true deficiency that is expected to impact capture system performance, as opposed to the language in 40 CFR part 60, subpart AAa that requires maintenance for ''any deficiency.'' Therefore, we agree with this aspect of the comment and are including the proposed rule language for monthly inspections that allow for operator discretion as to what issues ''materially impact'' the capture system performance in the final rule for 40 CFR part 60, subpart AAb (40 CFR 60.274b(d)).

Comment: A commenter asserted that the EPA should clarify the calculation for determining compliance with the opacity limits when using EPA Method 9 for 40 CFR part 60, subpart AAb. The commenter asked the EPA to clarify in the rule how facilities should determine compliance with the opacity limits. The commenter noted that compliance with the shop opacity limits will be determined based on the arithmetic average of 24 consecutive 15-second opacity observations over a 6-minute period. The commenter said that it is their understanding that the proposed zero opacity standard does not require all 24 15-second EPA Method 9 observation periods to be zero percent and that some of the 24 readings may exceed 0 percent provided the arithmetic average rounds down to 0. Similarly, in calculating compliance with the existing 6 percent shop opacity standard, some readings can exceed 6 percent provided the arithmetic average rounded down is below 6 percent. The commenter asked the EPA to confirm their interpretation of the rule is correct.

The commenter noted that this approach is consistent with prior NSPS rulemakings, including 40 CFR part 60, subpart KK (Lead-Acid Battery Manufacturing) and 40 CFR part 60, subpart NN (Phosphate Rock Plants). However, the commenter said the EPA specified in 40 CFR part 60, subparts KK and NN that compliance with the opacity standard is determined by taking the average opacity over a 6-minute period, according to EPA Method 9, and rounding the average to the nearest whole percentage (45 FR 2790 and 2794; January 14, 1980 and 47 FR 16564, 16566, 16582, and 16586; April 16, 1982). The commenter recommended the EPA add the same explanation provided in these earlier NSPS in the final shop opacity limit.

EPA Response: The method for calculating opacity has not changed substantially for 40 CFR part 60, subpart AAb; the final rule incorporates the current EPA Method 9 procedures for melting and refining, and for tapping (see section IV.B.2 in this preamble for changes to opacity measurement procedures with EPA Method 9 during charging). When determining the final value for opacity in 40 CFR part 60, subpart AAb, facilities should round to the nearest whole number (0 percent). Therefore, an average opacity level calculated to be 0.49 percent would round (down) to 0 percent.

3. What is the rationale for the final requirements for testing and monitoring?

We are finalizing the proposed requirement in 40 CFR part 60, subparts AA, AAa, and AAb that the melt shop be inspected for holes or other openings that would allow PM to escape because it clarifies the building inspection requirement already in the current NSPS. We are also incorporating into the final rules for 40 CFR part 60, subparts AA, AAa, and AAb the allowance of up to 24 hours to find and fix baghouse leaks following a BLDS alarm event because it is commensurate with many other EPA rules and no evidence exists for the specific need for limiting the tie period to 3 hours for EAF. The reasons that more than 3 hours and up to 24 hours is needed to respond to BLDS alarms provided by the commenter are valid. We are finalizing that sources complying with 40 CFR part 60, subpart AAb will be required to perform compliance testing every 5 years after the initial testing performed upon startup, as required under 40 CFR part 60.8. This requirement is already required in many of the permits for existing EAF in the EAF dataset and in the industry, and is a standard requirement for testing for other sources of PM emissions for many other industrial sectors.

We learned through public comments that some of the proposed monitoring changes, BLDS monitoring, furnace static pressure monitoring and operation, and volumetric flow and static pressure monitoring and operation, would require significant capital investment through equipment purchases. Therefore, these changes requiring purchases of equipment are not being finalized for 40 CFR part 60, subparts AA, AAa, and AAb.

We are finalizing 2 proposed monitoring requirements for 40 CFR part 60, subparts AA, AAa, and AAb, which are the requirements for melt shop inspection and stipulation that the melt shop opacity limits apply at all times during the designated periods of applicability under the rules. We are also finalizing the proposed damper position and fan amperage monitoring requirements with modifications. Other miscellaneous monitoring requirements also are being finalized with modifications resulting from comments on the proposed requirements, as described in in this section.

All testing and monitoring requirements proposed and finalized in this action were evaluated to ensure compliance with the NSPS emission standards under conditions of proper operation and maintenance. However, because we learned through comments that some of the proposed changes to monitoring in the existing NSPS rules would incur unintended costs, these requirements were either not finalized in their entirety or were finalized with modifications.

F. Electronic Reporting

The EPA is finalizing the proposed requirement that owners and operators of EAF and AOD subject to the current and new NSPS at 40 CFR part 60, subparts AA, AAa, and AAb submit electronic copies of required performance test reports and any semiannual excess emissions and continuous monitoring system performance and summary reports, through the EPA's CDX using the 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*,[18] available in the docket for this action, and hereafter referred to as the ''Electronic Reporting Memorandum.'' The finalized rule requires that performance test/demonstration of compliance results collected using test methods that are supported by the EPA's ERT as listed on the ERT website [19] at the time of the test be submitted in the format generated through the use of the ERT or an electronic file consistent with the xml schema on the ERT website, and other performance test/demonstration of compliance results be submitted in PDF using the attachment module of the ERT.

For semiannual reports, the finalized rule requires that owners and operators use the appropriate spreadsheet template to submit information to CEDRI. The final versions of the templates for these reports are included in the docket for this action.[20]

Additionally, the EPA has identified 2 broad circumstances in which electronic reporting extensions may be provided. These circumstances are: (1) Outages of the EPA's CDX or CEDRI which preclude an owner and operator from accessing the system and submitting required reports; and (2) *force majeure* events, which are defined as events that will be or have been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevent an owner and operator from complying with the requirement to submit a report electronically. Examples of *force majeure* events are acts of nature, acts of war or terrorism, equipment failure, or safety hazards beyond the control of the facility. The EPA is providing these potential extensions to protect owners and operators from noncompliance in cases where they cannot successfully submit a report by the reporting deadline for reasons outside of their control. In both circumstances, the decision to accept the claim of needing additional time to report is within the discretion of the Administrator, and reporting should occur as soon as possible.

The electronic submittal of the reports addressed in this final rulemaking increase the usefulness of the data

[18] *Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules.* Memorandum, Measurement Policy Group, U.S. Environmental Protection Agency, Research Triangle Park, NC. August 19, 2020.

[19] *https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert.*

[20] See 40 CFR part 60, subpart AA, AAa, and AAb, *Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels,* 40 CFR part 60.276(g) Semiannual Compliance Report Spreadsheet Template, available at Docket ID No. EPA–HQ–OAR–2002–0049–0064.

contained in those reports and is keeping with current trends in data availability and transparency. Electronic submittal would further assist in the protection of public health and the environment by improving compliance, facilitating the ability of regulated facilities to demonstrate compliance with requirements, and by facilitating the ability of delegated state, local, Tribal, and territorial air agencies and the EPA to assess and determine compliance. Ultimately, electronic reporting would reduce the burden on regulated facilities, delegated air agencies, and the EPA by making the data easy to record and read. Electronic reporting also eliminates paper waste and redundancies and minimizes data reporting errors. The resulting electronic data are more quickly and accurately accessible to the affected facilities, air agencies, the EPA, and the public. Moreover, electronic reporting is consistent with the EPA's plan [21] to implement Executive Order 13563 and is in keeping with the EPA's agency-wide policy [22] developed in response to the White House's Digital Government Strategy.[23] For more information on the benefits of electronic reporting, see the ''Electronic Reporting Memorandum'' discussed earlier in this section.

No comments were received on electronic reporting. Therefore, we are finalizing the requirements for electronic reporting as proposed.

G. Effective Date and Compliance Dates

Pursuant to CAA section 111(b)(1)(B), affected sources that commence construction, reconstruction, or modification after May 16, 2022, must comply with all requirements of 40 CFR part 60, subpart AAb, no later than August 25, 2023 or upon startup, whichever is later.

The date for complying with the ERT submission requirements is February 21, 2024. The date for complying with the changes in the current rules, 40 CFR part 60, subparts AA and AAa is February 21, 2024 publication of the final rule.

V. Summary of Cost, Environmental, and Economic Impacts

A. What are the air quality impacts?

For 40 CFR part 60, subpart AAb, reductions in PM and $PM_{2.5}$ potentially emitted from new, modified, and reconstructed EAF compared to these emissions allowed under the current NSPS subpart AAa with 6 percent melt shop opacity will have a beneficial air impact.

Based on the actual emissions emitted by 31 facilities in the EAF dataset, where the actual average opacity was 0.14 percent, the emissions impact for PM from 9 new, modified, or reconstructed EAF facilities projected in the next 10 years (estimated to reflect 3 small, 4 medium, and 2 large) is estimated to be an emissions reduction of 134 tons PM that would otherwise be emitted in 2032. Using an estimate of 0.218 [24] for the ratio of $PM_{2.5}$ to PM the emissions impact for $PM_{2.5}$ from nine new facilities projected in the next 10 years, as above, there would be an emissions reduction of 28 tons of $PM_{2.5}$ in 2032. Details of these emissions estimates can be found in the ''Emissions Memorandum'' discussed in section IV.A.2.

No actual PM emission reductions are estimated for the new PM limit for facility-wide total baghouse emissions in lb/ton. The EPA did not estimate PM emission reductions from new, modified, and reconstructed sources under the facility-wide total baghouse limit because based the 2010 EAF dataset, all facilities in the dataset are already achieving an emission level comparable to the limit being finalized in this action.

B. What are the secondary impacts?

A secondary impact as a result of this rule is that solid wastes may increase slightly, with an estimated 15 tons per facility per year based on 2010 EAF performance, with the potential additional waste from PM collected to meet the 0 percent melting and refining opacity limit under NSPS subpart AAb. The small increase in solid wastes would be the same for both the carbon and specialty steel shops. However, most PM collected from EAF is recycled to reclaim zinc, which also defrays some of the disposal costs.[25] [26]

Additionally, a relatively small increase in energy may result from the use of electricity to power fans that draw EAF and AOD exhaust air into the canopy hood that captures the PM and sends PM-laden air to the baghouse, at 66, 940, 4,700 MW-hr per year for small, medium, and large facilities, respectively. However, if the A/C ratio of the fabric filters is lowered to meet the facility baghouse standard due to an increase in number of bags, some decrease in energy use may occur.

Finally, there will be no water or noise impacts with the promulgated NSPS subpart AAb.

C. What are the cost impacts?

Costs were estimated for regular testing every 5 years for 9 new facilities projected in the 10 years after May 16, 2022. The estimated annual testing costs for each facility are $10,625 per year ($2022) for conducting EPA Method 5 for PM emissions at each baghouse's exhaust over a 5-year period, using an estimate of 1.64 baghouses per facility based on the EAF data. While new, modified, or reconstructed sources that start up after May 16, 2022, are subject to testing every 5 years under the finalized NSPS subpart AAb, EPA Method 5 testing is required upon initial startup under 40 CFR 60.8. Therefore, in the first 5 years after startup, there will be no testing costs as a result of the finalized rule. Then, in the sixth through the tenth year after initial startup after May16, 2022, the estimated new, modified, or reconstructed sources will incur costs of approximately $9,562 per year ($2022) per facility for testing, based on an estimate of 0.9 new, modified, or reconstructed facilities per year (0.9 × $10,625). Due to the estimated staggered startup of these new, modified, or reconstructed facilities, with 0.9 new, modified, or reconstructed facilities starting each year after the proposal (May 16, 2022), the total costs for testing for all new, modified, or reconstructed facilities under this rule after the initial testing required under 40 CFR part 60.8 will range from approximately $523,000 ($2022) in the sixth year after May 16, 2022 (corresponding to 5.4 new facilities), to a total of approximately $900,000 in the tenth year after May 16, 2022 (reflecting costs for 9 facilities, with testing costs of approximately

[21] EPA's Final Plan for Periodic Retrospective Reviews (August 2011). Available at: *https://www.regulations.gov/document?D=EPA-HQ-OA-2011-0156-0154.*

[22] E-Reporting Policy Statement for EPA Regulations (September 2013). Available at: *https://www.epa.gov/sites/default/files/2016-03/documents/epa-ereporting-policy-statement-2013-09-30.pdf.*

[23] Digital Government: Building a 21st Century Platform to Better Serve the American People (May 2012). Available at: *https://obamawhitehouse.archives.gov/sites/default/files/omb/egov/digital-government/digital-government.html.*

[24] The $PM_{2.5}$ to PM ratio is an average of similar uncontrolled sources, as cited in *Evaluation of $PM_{2.5}$ Emissions and Controls at Two Michigan Steel Mills and a Coke Oven Battery.* Final Report. Work Assignment 4–12 under EPA Contract No. 68–D–01–073 by RTI International, Research Triangle Park, NC. U.S. Environmental Protection Agency, Research Triangle Park, NC. February 2006.

[25] *Proven Waelz Kiln Technology.* Accessed 2/18/22. *http://www.globalsteeldust.com/waelz_kiln_technology.*

[26] Rütten, J. *Application of the Waelz Technology on Resource Recycling of Steel Mill Dust.* Düsseldorf: GmbH. D–40225, 2006.

$100,000 per facility per year), where the testing costs that would occur in years 6 through 10 are for the new, modified, or reconstructed facilities that start up in years 1 through 5 after May 16, 2022.

Based on information from 2010 through 2017 obtained by the EPA for 31 EAF facilities, the EPA found the average opacity to be 0.14 percent, with about half of the units achieving 0 percent opacity in the tests. Because opacity in the baseline is already low, the EPA expects any new, modified, or reconstructed facility would be able to meet the promulgated opacity and PM limits without any additional control devices beyond those already required by the NSR program, applicable state requirements or by minor process changes to improve capture of exhaust flows or other process parameters, if needed. While the actual cost impacts of the promulgated 0 percent opacity for melting and refining and 6 percent opacity for charging and tapping would likely be substantially lower, the EPA developed an upper bound estimate of potential compliance costs based upon the assumption that affected units would install a partial roof canopy above the crane rails to ensure 0 percent opacity during melting and refining and 6 percent opacity during charging and tapping compared to a hypothetical baseline model facility meeting 6 percent opacity at all times. These costs to achieve the opacity requirements are estimated to be $86,000, $1,140,000, $5,700,000 ($2022) per year per facility for small, medium, and large model facilities, respectively.

Total annual costs for NSPS subpart AAb, based on nine new, modified, or reconstructed facilities in the first 10 years after May 16, 2022, are $560,000 per year ($2022) for 3 small facilities, $4.9M per year for 4 medium facilities, and $11.5M per year for 2 large facilities, for a total of $17M per year ($2022) for 9 new facilities in the tenth year after May 16, 2022, using the same staggered startup rate described for testing costs. Details of the cost estimates for the final rule can be found in the ''Cost Memorandum'' discussed in section IV.A.2 (with proposal costs updated to 2022 [27]) which can be found in the docket for this rule.

For the promulgated mass-based PM standard in lb/ton for facility-wide total baghouse PM emissions, we estimated the capital and annual costs between a baseline scenario based on the current NSPS individual baghouse concentration limit (in gr/dscf) in 40 CFR part 60, subparts AA and AAa and a scenario based on a lower total facility-wide baghouse PM emissions in a mass-based limit (in lb/ton), which is the format for the standard of performance we are promulgating. Because data from the 31 existing EAF facilities in the 2010 dataset used by the EPA to develop the facility-wide PM limit show these facilities could already meet the 0.16 lb/ton total facility baghouse PM limit, we expect the promulgated mass-based standard applied to future new, modified, and reconstructed EAF facilities would be feasible and pose minimal cost impacts, if any.

Additional cost analysis, including calculation of costs using the upper bound cost estimates for the installation of partial roof canopies, can be found in the Economic Impact Analysis (EIA) associated with this final rule, which is available in the docket for this rule. The EIA additionally presents costs in terms of the present value and equivalent annual value of projected compliance costs over the 2023 to 2032 period discounted at 3 and 7 percent.

D. What are the economic impacts?

Economic impact analyses focus on changes in market prices and output levels. If changes in market prices and output levels in the primary markets are significant enough, impacts on other markets may also be examined. Both the magnitude of costs associated with the promulgated requirements and the distribution of these costs among affected facilities can have a role in determining how the market will change in response to a regulatory requirement. As discussed in section IV.B. of this preamble, the cost analysis incorporates the assumption that units affected by the new NSPS subpart AAb would install a partial roof canopy above the crane rails to ensure 0 percent melt shop opacity compared to a hypothetical baseline model facility meeting 6 percent opacity. The costs should be viewed as upper bound estimates on the potential compliance costs as the EPA expects any new, modified or reconstructed facility would be able to meet the promulgated opacity and PM limits without any additional control devices beyond those already required by the NSR program, applicable state requirements, or by minor process changes to improve capture of exhaust flows or other process parameters, if needed. As discussed in the EIA, even under the upper bound cost assumptions described, the EPA expects the potential economic impacts of this final rule will be small.

As required by the Regulatory Flexibility Act (RFA), we performed an analysis to determine if any small entities might be disproportionately impacted by the promulgated requirements. The EPA does not know what firms will construct new facilities in the future and, as a result, cannot perform a cost-to-sales analysis with the same confidence as we do with firms owning existing facilities. However, based on an assessment of the new units built during the 2011 to 2020 period and the units that have been announced, which are all owned by firms that are not considered to be small businesses, the EPA does not believe it is likely that any future facilities will be built by a small business. See the EIA in the docket for this action for additional information on the analysis presented in this section.

E. What are the benefits?

The new requirements being finalized in 40 CFR subpart AAb are expected to reduce PM emissions, including $PM_{2.5}$. In addition, the revisions to 40 CFR part 60, subparts AA and AAa will clarify the rules, enhance compliance and enforcement, and is expected to reduce PM emissions, including $PM_{2.5}$. As explained in section IV.A of this preamble, the requirements are projected to reduce 28 tons of $PM_{2.5}$ in 2032. These emissions reductions are expected to produce health benefits in the affected locations. The *Integrated Science Assessment for Particulate Matter* (ISA) [28] contains synthesized toxicological, clinical, and epidemiological evidence that the EPA uses to determine whether each pollutant is causally related to an array of adverse human health outcomes associated with either acute (*i.e.,* hours or days-long) or chronic (*i.e.,* years-long) exposure. For each outcome, the ISA includes the EPA conclusions as to whether this relationship is causal, likely to be causal, suggestive of a causal relationship, inadequate to infer a causal relationship, or not likely to be a causal relationship.

In the ISA, it was found that acute exposure to $PM_{2.5}$ was causally related to cardiovascular effects and mortality (*i.e.,* premature death), and respiratory

[27] In the time since the proposal costs were assessed in 2020, inflation has increased with a subsequent increase in the gross national product (GNP), which is the basis for the U.S. dollars used in the costs estimates. In addition, interest rates, which affect capital costs, increased from 3.5 percent to 7.5 percent from proposal cost preparation (in 2021) to final rule cost preparation (in 2022).

[28] *Integrated Science Assessment for Particulate Matter* (Final Report, 2019). EPA/600/R19/188. U.S. Environmental Protection Agency, Washington, DC. 2019.

effects as likely-to-be-causally related. Further, the EPA identified cardiovascular effects and total mortality as causally related to long-term exposure to $PM_{2.5}$ and respiratory effects as likely-to-be-causal; the evidence was suggestive of a causal relationship for reproductive and developmental effects as well as cancer, mutagenicity, and genotoxicity.

The benefits per ton (BPT) of the $PM_{2.5}$ emissions reductions cited earlier in this preamble for years 2025 and 2030 and at 3 percent and 7 percent discount rates are presented in Table 7 below in 2022 dollars. The BPT of the $PM_{2.5}$ emissions reductions for year 2025, at a 3 percent discount rate translates to a low projection of $417,000 per ton emission reduction, to a high projection of $891,000 per ton emission reduction (in 2022 dollars). Information regarding the process by which these BPTs were calculated is available in the 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*.

TABLE 7—BENEFITS PER TON OF $PM_{2.5}$ REDUCED

Year	$/ton $PM_{2.5}$ emission reductions $2022			
	3 Percent discount rate		7 Percent discount rate	
	Low	High	Low	High
2025	$417,000	$891,000	$375,000	$803,000
2030	451,000	933,000	405,000	839,000

Note: The range reported here reflects the use of risk estimates from two alternative long-term exposure PM-mortality studies.[29]

F. What analysis of environmental justice did we conduct?

Executive Order 12898 directs the EPA to identify the populations of concern that are most likely to experience unequal burdens from environmental harms, which are specifically minority populations (people of color), low-income populations, and Indigenous peoples (59 FR 7629; February 16, 1994). Additionally, Executive Order 13985 is intended to advance racial equity and support underserved communities through Federal government actions (86 FR 7009; January 20, 2021). 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.'' [30] 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.'' In recognizing that people of color and low-income populations 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,'' [31] 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 minority populations, low-income populations, and/or Indigenous peoples; (2) exacerbate existing disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples; or (3) present opportunities to address existing disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples through this action under development.

The Agency has conducted an analysis of the demographics of the populations living near existing facilities in the EAF population in the U.S. Because this action finalizes standards of performance for new, modified, and reconstructed EAF sources that commence construction after May 16, 2022, the locations of the construction of new EAF facilities are not known. In addition, it is not known which of the existing facilities will be modified or reconstructed in the future. Therefore, the demographic analysis was conducted for the 88 existing EAF facilities as a characterization of the demographics in areas where these facilities are now located.

The full results of the demographic analysis can be found in section E, ''*What are the environmental justice impacts?,*'' of the preamble to the proposed rule (87 FR 29724). The analysis included an assessment of individual demographic groups of the populations living within 5 km and within 50 km of the existing facilities. We then compared the data from the analysis to the national average for each of the demographic groups. The results show that for populations within 5 km of the 87 existing EAF facilities (we identified one additional existing facility since the proposed rule was published for a total of 88 facilities, but the overall results did not change). The percent of the population that is African American is above the national average (17 percent versus 12 percent). The percent of people living below the poverty level is also above the national average (17 percent versus 13 percent). The percent of the population that is Native American, Hispanic or Latino, or Other/Multiracial are below the national averages. The percent of the population over 25 without a high school diploma and the percent of the population in linguistic isolation are similar to the national averages. The results of the analysis of populations within 50 km of the 88 EAF facilities is similar to the 5 km analysis.

The methodology and the results of the demographic analysis for the final rule are presented in a technical report, *Analysis of Demographic Factors for Populations Living Near Electric Arc Furnace Facilities,* available in the docket for this action (Docket ID No. EPA–HQ–OAR–2002–0049).

[29] *Estimating the Benefit per Ton of Reducing Directly-emitted $PM_{2.5}$, $PM_{2.5}$ Precursors and Ozone Precursors from 21 Sectors*. U.S. Environmental Protection Agency, Office of Air and Radiation, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711. 2022. Available at: *https://www.epa.gov/system/files/documents/2021-10/source-apportionment-tsd-oct-2021_0.pdf.*

[30] See *https://www.epa.gov/environmentaljustice.*

[31] See *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

The EPA expects that the Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed after May 16, 2022, will ensure compliance via frequent testing and reduce emissions via a lower opacity limit for melt shops and with the standards at all times (including periods of SSM). The rule will also increase data transparency through electronic reporting. Therefore, effects of emissions on populations in proximity to any future affected sources, including in communities potentially overburdened by pollution, which are often people of color, and low-income and Indigenous communities will be reduced due to compliance with the standards of performance being finalized in this action.

VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://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)

The information collection activities in this final rule have been submitted for approval to OMB under the PRA. The information collection request (ICR) document that the EPA prepared has been assigned the EPA ICR number 1060.21. 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.

These amendments to 40 CFR part 60, subparts AA and AAa to require electronic reporting, and implement editorial and clarifying changes to rule language are estimated to reduce time spent and paperwork for rule. We are promulgating a new subpart for new, modified, or reconstructed facilities that start up after May 16, 2022, under 40 CFR part 60, subpart AAb with similar reporting, recordkeeping, and compliance requirements as 40 CFR part 60, subparts AA and AAa.

Respondents/affected entities: EAF and AOD facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subparts AA; AAa; and AAb).

Estimated number of respondents: 90, includes 88 estimated current facilities subject to 40 CFR part 60, subparts AA and AAa, and 3 new facilities that would be subject to 40 CFR part 60, subpart AAb in the 3 years after proposal (May 16, 2022).

Frequency of Response: One time.

Total estimated burden: The annual recordkeeping and reporting burden for facilities to comply with all the requirements in the NSPS is estimated to be 57,100 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 of the requirements in the NSPS is estimated to be $7,400,000 (per year), of which $65,686 (per year) is for this final rule ($60,000 for EPA Method 5 compliance and $696 for electronic reporting), and $7,130,000 for other costs related to continued compliance with the NSPS, including $198,000 for paperwork associated with operation and maintenance requirements. The total rule costs reflect an increase/decrease cost of $450,000 (per year) from the previous ICR that reflects savings due to electronic reporting and an increase to the labor rates.

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 the three identified small entities among the approximately 90 EAF facilities (36 companies), because most facilities are likely to be performing regular compliance tests as part of their permit renewal process. Additionally, no facilities are expected to be built by small entities over the next 10 years based on past industry growth and small business starts. The 3 current facilities owned by small businesses were started in 1912, 1968, and 1994, respectively. Further discussion is included in the EIA for this final rule.

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 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. This rule will implement improvements in air quality due to new EAF in all locations of new EAF facilities, including any new EAF which are in proximity to Tribal grounds. It would 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 that are the subject of this rulemaking. Thus, Executive Order 13175 does not apply to this action.

Consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA consulted with Tribal officials during the development of this action. A copy of the memorandum dated May 17, 2022, sent to Tribal leaders concerning the EAF NSPS is provided in the docket to this rule.

G. 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 economically significant as defined in 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. The EPA does not believe there are disproportionate risks to children because the new subpart AAb lowers emissions from the melt shop during melting and refining, which will benefit children's health; and other changes made to all subparts, AA, AAa, and AAb, increase compliance with emission limits, which also benefits children's health. However, EPA's Policy on Children's Health applies to this action. Information on how the Policy was applied is available under ''Children's Environmental Health'' in the Supplementary Information section of this preamble.

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 action involves technical standards. Therefore, the EPA conducted searches for the EAF NSPS through the Enhanced National Standards Systems Network Database managed by the American National Standards Institute (ANSI). We also contacted voluntary consensus standards (VCS) organizations and accessed and searched their databases. We conducted searches for EPA Methods 1, 2, 3, 3A, 3B, 4, 5, 5D, and 22 of 40 CFR part 60, appendix A. 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 reference method, the EPA 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 reference methods. The EPA may reconsider determinations of impracticality when additional information is available for a particular VCS. No applicable VCS were identified for EPA Methods 5D and 22.

The EPA is incorporating by reference the VCS ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' to provide that the manual procedures (but not instrumental procedures) of VCS ANSI/ASME PTC 19.10–1981—Part 10 may be used as an alternative to EPA Method 3B. The manual procedures (but not instrumental procedures) of VCS ANSI/ASME PTC 19.10–1981—Part 10 may be used as an alternative to EPA Method 3B for measuring the oxygen or carbon dioxide content of the exhaust gas. This standard is acceptable as an alternative to EPA Method 3B and is available from ASME at *www.asme.org;* by mail at Three Park Avenue, New York, NY 10016–5990; or by telephone at (800) 843–2763. This method determines quantitatively the gaseous constituents of exhausts resulting from stationary combustion sources. The gases covered in ANSI/ASME PTC 19.10–1981 are oxygen, carbon dioxide, carbon monoxide, nitrogen, sulfur dioxide, sulfur trioxide, nitric oxide, nitrogen dioxide, hydrogen sulfide, and hydrocarbons. However, the use in this rule is only applicable to oxygen and carbon dioxide.

In the final rule, the EPA is incorporating by reference the VCS ASTM D7520–16, Standard Test Method for Determining the Opacity of a Plume in the Outdoor Ambient Atmosphere, which 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 DCOT method is an acceptable alternative to EPA Method 9 with the following caveats:

- During the DCOT certification procedure outlined in Section 9.2 of ASTM D7520–16, the facility 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 or a sparse tree stand).
- The facility 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.
- The facility must follow the recordkeeping procedures outlined in 40 CFR 63.10(b)(1) for the DCOT certification, compliance report, data sheets, and all raw unaltered JPEGs used for opacity and certification determination.
- The facility or the DCOT vendor must have a minimum of 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 any one anyone reading, and the average error must not exceed 7.5 percent opacity.
- 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 or training of the DCOT camera, software, and operator in accordance with ASTM D7520–16 is on the facility, DCOT operator, and DCOT vendor. This method describes procedures to determine the opacity of a plume, using digital imagery and associated hardware and software, where opacity is caused by PM emitted from a stationary point source in the outdoor ambient environment. The opacity of emissions is determined by the application of a DCOT that consists of a digital still camera, analysis software, and the output function's content to obtain and interpret digital images to determine and report plume opacity. The ASTM D7520–16 document is available from ASTM at *www.astm.org* or 1100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, telephone number: (610) 832–9500, fax number: (610) 832–9555 at *service@astm.org.*

The EPA is finalizing the use of the guidance document, *Fabric Filter Bag Leak Detection Guidance,* EPA–454/R–98–015, Office of Air Quality Planning and Standards (OAQPS), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, September 1997. This document provides guidance on the use of triboelectric monitors as fabric filter bag leak detectors. The document includes fabric filter and monitoring system descriptions; guidance on monitor selection, installation, setup, adjustment, and operation; and quality assurance procedures. The document is available at *https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=2000D5T6.PDF.*

Additional information for the VCS search and determinations can be found in the three memoranda titled *Voluntary Consensus Standard Results for Standards of Performance for Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974, and*

On or Before August 17, 1983; Voluntary Consensus Standard Results for Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 17, 1983, and On or Before May 16, 2022; and *Voluntary Consensus Standard Results for Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After May 16, 2022,* available in the docket for this final rule.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629; February 16, 1994) directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations (people of color and/or Indigenous peoples) and low-income populations.

The EPA believes that the human health and environmental conditions that exist prior to this action do not result in disproportionate and adverse effects on people of color, low-income populations, and/or indigenous peoples if a modified or reconstructed EAF facility becomes subject to the final rule for 40 CFR part 60, subpart AAb, considering the demographics analysis for the existing EAF facilities described in section V.F of this preamble. However, it is unknown where new EAF facilities will be located so it is not possible to predict the impacts of these facilities on people of color, low-income populations, and/or indigenous peoples.

The EPA believes that this action is not likely to result in new disproportionate and adverse effects on people of color, low-income populations and/or indigenous peoples. The impacts of these final rules are beneficial to all demographic groups, and include requirements to clarify current rules in 40 CFR part 60, subparts AA, AAa and, for new sources built after publication of this final rule (in 40 CFR part 60, subpart AAb), to ensure compliance via frequent testing, to meet a lower opacity limit for melt shops during melting and refining, to meet a baghouse emissions limit as a facility-wide total in lb/ton, and to meet all the promulgated standards at all times, including periods of SSM.

The information supporting this Executive Order review is contained in section V.F of this preamble and in a technical report, *Analysis of Demographic Factors For Populations Living Near Steel Plants Using Electric Arc Furnaces,* located in the docket for this rule. Because the EPA does not know where new facilities will be located that will become subject to this new 40 CFR part 60, subpart AAb, a demographic analysis was performed on the existing EAF/AOD population, which could become subject to 40 CFR part 60, subpart AAb if a modification or reconstruction increases emissions.

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 60

Environmental protection, Administrative practice and procedures, Air pollution control, Incorporation by reference, Reporting and recordkeeping requirements.

Michael S. Regan,

Administrator.

For the reasons set forth in the preamble, the EPA amends 40 CFR part 60 as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

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

Subpart A—General Provisions.

■ 2. Section 60.17 is amended by revising paragraphs (g)(14), (h)(206), and (j)(2) to read as follows:

§ 60.17 Incorporation by reference.

* * * * *

(g) * * *

(14) ASME/ANSI PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], (Issued August 31, 1981), IBR approved for §§ 60.56c(b); 60.63(f); 60.106(e); 60.104a(d), (h), (i), and (j); 60.105a(b), (d), (f), and (g); 60.106a(a); 60.107a(a), (c), and (d); 60.275(e); 60.275a(e); 60.275b(e); tables 1 and 3 to subpart EEEE; tables 2 and 4 to subpart FFFF; table 2 to subpart JJJJ; §§ 60.285a(f); 60.396(a); 60.2145(s) and (t); 60.2710(s) and (t); 60.2730(q); 60.4415(a); 60.4900(b); 60.5220(b); tables 1 and 2 to subpart LLLL; tables 2 and 3 to subpart MMMM; §§ 60.5406(c); 60.5406a(c); 60.5407a(g); 60.5413(b); 60.5413a(b); and (d).

* * * * *

(h) * * *

(206) 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 §§ 60.271(k); 60.272(a) and (b); 60.273(c) and (d); 60.274(h); 60.275(e); 60.276(c); 60.271a; 60.272a(a) and (b); 60.273a(c) and (d); 60.274a(h); 60.275a(e); 60.276a(f); 60.271b; 60.272b(a) and (b); 60.273b(c) and (d); 60.274b(h); 60.275b(e); 60.276b(f); 60.374a(d).

* * * * *

(j) * * *

(2) EPA–454/R–98–015, Office of Air Quality Planning and Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance, September 1997, *https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=2000D5T6.PDF;* IBR approved for §§ 60.273(e); 60.273a(e); 60.273b(e); 60.373a(b); 60.2145(r); 60.2710(r); 60.4905(b); 60.5225(b).

* * * * *

Subpart AA—Standards of Performance for Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974, and On or Before August 17, 1983

■ 3. Section 60.270 is amended by revising paragraph (b) to read as follows:

§ 60.270 Applicability and designation of affected facility.

* * * * *

(b) The provisions of this subpart apply to each affected facility identified in paragraph (a) of this section that commenced construction, modification, or reconstruction after October 21, 1974, and on or before August 17, 1983, where a modification is any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which this standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which this standard applies) into the atmosphere not previously emitted.

■ 4. Section 60.271 is amended by:

■ a. Revising paragraphs (a), (d) through (f), (i) through (k), (m), and (n); and

■ b. Adding new paragraphs (p) through (r).

The revisions and additions read as follows:

§ 60.271 Definitions.

* * * * *

(a) *Electric arc furnace (EAF)* means a furnace that produces molten steel and heats the charge materials with electricity using carbon electrodes. Furnaces that continuously feed direct-reduced iron ore pellets as the primary source of iron are not affected facilities within the scope of this definition.

* * * * *

(d) *Capture system* means the equipment (including ducts, hoods, fans, dampers, etc.) used to capture particulate matter generated by the operation of an EAF and transport captured particulate matter to the air pollution control device.

(e) *Charge* means the addition of iron and steel scrap or other materials into the shell of an electric arc furnace.

(f) *Charging period* means the time period when iron and steel scrap or other materials are added into the top of an EAF until the melting and refining period commences.

* * * * *

(i) *Melting and refining* means that phase of the steel production cycle when charge material is melted and undesirable elements are removed from the metal.

(j) *Melting and refining period* means the time period commencing at the initial energizing of the electrode to begin the melting process and ending at the initiation of the tapping period, excluding any intermediate times when the electrodes are not energized as part of the melting process.

(k) *Shop opacity* means the arithmetic average of 24 or more opacity observations of any EAF emissions emanating from, and not within, the shop, taken in accordance with EPA Method 9 of appendix A of this part. Alternatively, ASTM D7520–16 (incorporated by reference, see § 60.17), may be used with the following five conditions: (1) During the digital camera opacity technique (DCOT) certification procedure outlined in Section 9.2 of ASTM D7520–16 (incorporated by reference, see § 60.17), the owner or operator 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) 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 § 60.17);

(3) The owner or operator must follow the recordkeeping procedures outlined in § 60.7(f) for the DCOT certification, compliance report, data sheets, and all raw unaltered JPEGs used for opacity and certification determination;

(4) 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 anyone reading and the average error must not exceed 7.5 percent opacity;

(5) 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 § 60.17) and these requirements is on the facility, DCOT operator, and DCOT vendor.

* * * * *

(m) *Shop* means the building that houses one or more EAF's and serves as the point from which compliance with § 60.272(a)(3), ''Standard for Particulate Matter,'' is measured.

(n) *Direct shell evacuation system* means any system that creates and maintains a negative pressure within the EAF shell during melting and refining, and transports emissions to the control device.

* * * * *

(p) *Damper* means any device used to open, close or throttle a DEC system or hood designed to capture emissions from an EAF and route them to the associated control device(s). It does not include isolation dampers used to isolate a fan or baghouse compartment for repair or cleaning, or dampers controlling collection of emissions from equipment other than an EAF.

(q) *Negative-pressure fabric filter* means a fabric filter with the fans on the downstream side of the filter bags.

(r) *Positive-pressure fabric filter* means a fabric filter with the fans on the upstream side of the filter bags.

■ 5. Section 60.272 is amended by revising paragraphs (a)(2), (a)(3) introductory text, and (b) to read as follows:

§ 60.272 Standard for particulate matter.

(a) * * *

(2) Exit from a control device and exhibit three percent opacity or greater, as measured in accordance with EPA Method 9 of appendix A of this part, or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271.

(3) Exit from a shop and, due solely to operations of any EAF(s), exhibit 6 percent opacity or greater, as measured in accordance with EPA Method 9 of appendix A of this part, or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271. Shop opacity shall be recorded for any point(s) where visible emissions are observed. Where it is possible to determine that a number of visible emission sites relate to only one incident of visible emissions, only one observation of shop opacity will be required. In this case, the shop opacity observations must be made for the site of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident, except:

* * * * *

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from dust-handling equipment any gases which exhibit 10 percent opacity or greater, as measured in accordance with EPA Method 9 of appendix A of this part, or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271.

■ 6. Section 60.273 is amended by:

■ a. Revising paragraphs (c), (d), (e) introductory text and (e)(3);

■ b. In paragraph (e)(4) introductory text, remove the text ''the U.S. Environmental Protection Agency guidance document ''Fabric Filter Bag Leak Detection Guidance'' (EPA–454/R–98–015)'' and add, in its place, the text ''EPA–454/R–98–015, Fabric Filter Bag Leak Detection Guidance (incorporated by reference, see § 60.17)'';

■ c. Revising paragraphs (e)(6)(ii), and (7), (f) introductory text, and (f)(1) and (5);

■ d. Redesignating paragraph (f)(6) as paragraph (f)(7);

■ e. Adding new paragraph (f)(6); and

■ f. Revising paragraph (g).

The revisions and addition read as follows:

§ 60.273 Emission monitoring.

* * * * *

(c) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the control device(s) is not required on any modular, multi-stack, negative-pressure or positive-pressure fabric filter or on any single-stack fabric filter if observations of the opacity of the visible emissions from the control device are performed by a certified visible emission observer and the owner installs and operates a bag leak detection system according to paragraph (e) of this section whenever the control device is being used to remove particulate matter from the EAF. Visible emission observations shall be conducted at least once per day of the control device for at least three 6-minute periods when the furnace is operating in the melting and refining period. All visible emissions observations shall be conducted in accordance with EPA Method 9 of appendix A to this part, or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271. If visible emissions occur from more than one point, the opacity shall be recorded for any points where visible emissions are observed. Where it is possible to determine that a number of visible emission points relate to only one incident of the visible emission, only one set of three 6-minute observations will be required. In that case, the EPA Method 9 observations must be made for the point of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident. Records shall be maintained of any 6-minute average that is in excess of the emission limit specified in § 60.272(a)(2).

(d) A furnace static pressure monitoring device is not required on any EAF equipped with a DEC system if observations of shop opacity are performed by a certified visible emission observer as follows:

(1) At least once per day when the furnace is operating.

(2) No less than once per week, commencing from the tap of one EAF heat cycle to the tap of the following heat cycle. A melt shop with more than one EAF shall conduct these readings while both EAFs are in operation. Both EAFs are not required to be on the same schedule for tapping.

(3) Shop opacity shall be determined as the arithmetic average of 24 or more consecutive 15-second opacity observations of emissions from the shop taken in accordance with EPA Method 9, or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271. Shop opacity shall be recorded for any point(s) where visible emissions are observed in proximity to an affected EAF. Where it is possible to determine that a number of visible emission points relate to only one incident of visible emissions, only one observation of shop opacity will be required. In this case, the shop opacity observations must be made for the point of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident.

(e) A bag leak detection system must be installed on all single-stack fabric filters and operated whenever the control device is being used to remove particulate matter from the EAF if the owner or operator elects not to install and operate a continuous opacity monitoring system as provided for under paragraph (c) of this section. In addition, the owner or operator shall meet the visible emissions observation requirements in paragraph (c) of this section. The bag leak detection system must meet the specifications and requirements of paragraphs (e)(1) through (8) of this section.

* * * * *

(3) The bag leak detection system must be equipped with an alarm system that will activate when an increase in relative particulate loading is detected over the alarm set point established according to paragraph (e)(4) of this section, and the alarm must be located such that it can be identified by the appropriate plant personnel.

* * * * *

(6) * * *

(ii) If opacities greater than zero percent are observed over four consecutive 15-second observations during the daily opacity observations required under paragraph (c) of this section and the alarm on the bag leak detection system alarm is not activated, the owner or operator shall lower the alarm set point on the bag leak detection system to a point where the alarm would have been activated during the period when the opacity observations were made.

(7) For negative pressure, induced air baghouses, and positive pressure baghouses that are discharged to the atmosphere through a stack, the bag leak detection sensor must be installed downstream of the baghouse or upstream of any wet scrubber.

* * * * *

(f) For each bag leak detection system installed according to paragraph (e) of this section, the owner or operator shall initiate procedures to determine the cause of all alarms within 1 hour of an alarm. The cause of the alarm must be alleviated within 24 hours of the time the alarm occurred by taking whatever response action(s) are necessary. Response actions may include, but are not limited to the following:

(1) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may have caused an increase in particulate emissions;

* * * * *

(5) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system;

(6) Establishing to the extent acceptable by the delegated authority that the alarm was a false alarm and not caused by a bag leak or other malfunction that could reasonably result in excess particulate emissions; or

* * * * *

(g) In approving the site-specific monitoring plan required in paragraph (e)(4) of this section, the Administrator or delegated authority may allow owners or operators more than 24 hours to alleviate specific conditions that cause an alarm if the owner or operator identifies the condition that could lead to an alarm in the monitoring plan, adequately explains why it is not feasible to alleviate the condition within 24 hours of the time the alarm occurred, and demonstrates that the requested additional time will ensure alleviation of the condition as expeditiously as practicable.

■ 7. Section 60.274 is amended by revising paragraphs (b) through (g), and (i) to read as follows:

§ 60.274 Monitoring of operations.

* * * * *

(b) Except as provided under paragraph (d) of this section, the owner or operator subject to the provisions of this subpart shall:

(1) Monitor and record on a continuous basis the rolling 15-minute average furnace static pressure (if a DEC system is in use, and a furnace static pressure gauge is installed according to paragraph (f) of this section) and either:

(i) Install, calibrate, and maintain a monitoring device that continuously records the capture system fan motor amperes and damper position(s);

(ii) Install, calibrate, and maintain a monitoring device that continuously records on a rolling 15-minute average basis either the volumetric flow rate through each separately ducted hood; or

(iii) Install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate at the control device inlet and continuously record damper position(s).

(2) The volumetric flow monitoring device(s) may be installed in any appropriate location in the capture system such that reproducible flow rate monitoring will result. The flow rate monitoring device(s) shall have an

accuracy of ±10 percent over its normal operating range and shall be calibrated according to the manufacturer's instructions. The Administrator may require the owner or operator to demonstrate the accuracy of the monitoring device(s) relative to EPA Methods 1 and 2 of appendix A of this part.

(3) Parameters monitored pursuant to this paragraph, excluding damper position, shall be recorded on a rolling averaging period not to exceed 15 minutes.

(c) When the owner or operator of an affected facility is required to demonstrate compliance with the standards under § 60.272(a)(3) and at any other time that the Administrator may require (under section 114 of the CAA, as amended), the owner or operator shall determine during periods in which a hood is operated for the purpose of capturing emissions from the affected facility subject to paragraph (b) of this section, either:

(1) Monitor and record the fan motor amperes at each damper position, and damper position consistent with paragraph (i)(5) of this section;

(2) install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate through each separately ducted hood; or

(3) install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate at the control device inlet and monitor and record the damper position consistent with paragraph (i)(5) of this section.

(4) Parameters monitored pursuant to this paragraph, excluding damper position, shall be recorded on a rolling averaging period not to exceed 15 minutes.

(5) The owner or operator may petition the Administrator or delegated authority for reestablishment of these parameters whenever the owner or operator can demonstrate to the Administrator's or delegated authority's satisfaction that the EAF operating conditions upon which the parameters were previously established are no longer applicable. The values of the parameters as determined during the most recent demonstration of compliance shall be the appropriate operational range or control set point throughout each applicable period. Operation at values beyond the accepted operational range or control set point may be subject to the requirements of § 60.276(a).

(d) The owner or operator may petition the Administrator or delegated authority to approve any alternative method that will provide a continuous record of operation of each emission capture system.

(e) The owner or operator shall perform monthly operational status inspections of the equipment that is important to the performance of the total capture system (*i.e.,* pressure sensors, dampers, and damper switches). This inspection shall include observations of the physical appearance of the equipment (*e.g.,* presence of hole in ductwork or hoods, flow constrictions caused by dents or excess accumulations of dust in ductwork, and fan erosion) and building inspections to ensure that the building does not have any holes or other openings for particulate matter laden air to escape. Any deficiencies that are determined by the operator to materially impact the efficacy of the capture system shall be noted and proper maintenance performed.

(f) Except as provided for under § 60.273(d), where emissions during any phase of the heat time are controlled by use of a direct shell evacuation system, the owner or operator shall install, calibrate, and maintain a monitoring device that continuously records the pressure in the free space inside the EAF. The pressure shall be recorded as no greater than 15-minute integrated block averages. The monitoring device may be installed in any appropriate location in the EAF or DEC duct prior to the introduction of ambient air such that reproducible results will be obtained. The pressure monitoring device shall have an accuracy of ±5 mm of water gauge over its normal operating range and shall be calibrated according to the manufacturer's instructions.

(g) Except as provided for under § 60.273(d), when the owner or operator of an EAF is required to demonstrate compliance with the standard under § 60.272(a)(3) and at any other time the Administrator may require (under section 114 of the Act, as amended), the pressure in the free space inside the furnace shall be determined during the melting and refining period(s) using the monitoring device under paragraph (f) of this section. The owner or operator may petition the Administrator or delegated authority for reestablishment of the 15-minute integrated average pressure whenever the owner or operator can demonstrate to the Administrator's or delegated authority's satisfaction that the EAF operating conditions upon which the pressures were previously established are no longer applicable. The pressure range or control setting during the most recent demonstration of compliance shall be maintained at all times the EAF is operating in a melting and refining period. Continuous operation at pressures higher than the operational range or control setting may be considered by the Administrator or delegated authority to be unacceptable operation and maintenance of the affected facility.

* * * * *

(i) During any performance test required under § 60.8, and for any report thereof required by § 60.276(c) of this subpart or to determine compliance with § 60.272(a)(3) of this subpart, the owner or operator shall monitor the following information for all heats covered by the test:

(1) Charge weights and materials, and tap weights and materials;

(2) Heat times, including start and stop times, and a log of process operation, including periods of no operation during testing and, if a furnace static pressure monitoring device is operated pursuant to paragraph (f) of this section, the pressure inside the furnace when DEC systems are used;

(3) Control device operation log;

(4) Continuous opacity monitor or EPA Method 9 data, or, as an alternative to EPA Method 9, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271;

(5) All damper positions, no less frequently than performed in the latest melt shop opacity compliance test for a full heat, if selected as a method to demonstrate compliance under paragraph (b) of this section;

(6) Fan motor amperes at each damper position, if selected as a method to demonstrate compliance under paragraph (b) of this section;

(7) Volumetric air flow rate through each separately ducted hood, if selected as a method to demonstrate compliance under paragraph (b) of this section; and

(8) Static pressure at each separately ducted hood, if selected as a method to demonstrate compliance under paragraph (b) of this section.

(9) Parameters monitored pursuant to paragraphs (i)(6)–(8) of this section shall be recorded on a rolling averaging period not to exceed 15 minutes.

■ 8. Section 60.275 is amended by:

■ a. Revising paragraphs (a) and (b)(2);

■ b. Adding paragraph (b)(3);

■ c. Revising paragraphs (c), (e)(1), (3), and (4);

■ d. Removing paragraph (g);

■ e. Redesignating existing paragraphs (h) through (j) as paragraphs (g) through (i), respectively; and

■ f. Revising newly redesignated paragraphs (g) introductory text, (g)(3), and (h).

The revisions and additions read as follows:

§ 60.275 Test methods and procedures.

(a) During performance tests required in § 60.8, the owner or operator shall not add gaseous diluent to the effluent gas after the fabric filter in any pressurized fabric collector, unless the amount of dilution is separately determined and considered in the determination of emissions.

(b) * * *

(2) Use a method that is acceptable to the Administrator or delegated authority and that compensates for the emissions from the facilities not subject to the provisions of this subpart.

(3) Any combination of the criteria of paragraphs (b)(1) and (b)(2) of this section.

(c) When emissions from any EAF(s) are combined with emissions from facilities not subject to the provisions of this subpart, compliance with § 60.272(a)(3) will be based on emissions from only the affected facility(ies). The owner or operator may use operational knowledge to determine the facilities that are the sources, in whole or in part, of any emissions observed in demonstrations of compliance with § 60.272(a)(3).

* * * * *

(e) * * *

(1) EPA Method 5 (and referenced EPA Methods 1, 2, 3, 3A, 3B, and 4) shall be used for negative-pressure fabric filters and other types of control devices and EPA Method 5D (and referenced EPA Method 5) shall be used for positive-pressure fabric filters to determine the particulate matter concentration and, if applicable, the volumetric flow rate of the effluent gas. The sampling time and sample volume for each run shall be at least 4 hours and 4.5 dscm (160 dscf) and, when a single EAF is sampled, the sampling time shall include an integral number of heats. The manual portions only and not the instrumental portion of the voluntary consensus standard ANSI/ASME PTC 19.10–1981 (incorporated by reference, see § 60.17) is an acceptable alternative to EPA Methods 3, 3A, and 3B.

* * * * *

(3) EPA Method 9 or, as an alternative, ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271, and the procedures of § 60.11 shall be used to determine opacity.

(4) To demonstrate compliance with § 60.272(a)(1), (2), and (3), the EPA Method 9 test runs shall be conducted concurrently with the particulate matter test runs, unless inclement weather interferes.

* * * * *

(g) Where emissions from any EAF(s) are combined with emissions from facilities not subject to the provisions of this subpart, the owner or operator may use any of the following procedures for demonstrating compliance with § 60.272(a)(3), except if the combined emissions are controlled by a common capture system and control device, in which case the owner or operator may use any of the following procedures during an opacity performance test and during shop opacity observations:

* * * * *

(3) Any combination of the criteria of paragraphs (g)(1) and (2) of this section.

(h) If visible emissions observations are made in lieu of using a continuous opacity monitoring system, as allowed for by § 60.273(c), visible emission observations shall be conducted at least once per day for at least three 6-minute periods when the furnace is operating in the melting and refining period. All visible emissions observations shall be conducted in accordance with EPA Method 9. If visible emissions occur from more than one point, the opacity shall be recorded for any points where visible emissions are observed. Where it is possible to determine that a number of visible emission sites relate to only one incident of the visible emission, only one set of three 6-minute observations will be required. In that case, the EPA Method 9 observations must be made for the site of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident. Records shall be maintained of any 6-minute average that is in excess of the emission limit specified in § 60.272(a).

* * * * *

■ 9. Section 60.276 is amended by:

■ a. Revising paragraphs (a), (b), (c) introductory text, (c)(3), (4), (6)(iv), (10), (d), and (e)(3); and

■ b. Adding paragraphs (f) through (k).

The revisions and additions read as follows:

§ 60.276 Recordkeeping and reporting requirements.

(a) Continuous operation at a furnace static pressure that exceeds the operational range or control setting under § 60.274(g), for owners and operators that elect to install a furnace static pressure monitoring device under § 60.274(f) or operation at flow rates lower than those established under § 60.274(c) may be considered by the Administrator or delegated authority to be unacceptable operation and maintenance of the affected facility. Operation at such values shall be reported to the Administrator or delegated authority semiannually.

(b) When the owner or operator of an EAF is required to demonstrate compliance with the standard under § 60.275(b)(2) or a combination of (b)(1) and (b)(2), the owner or operator shall provide notice to the Administrator or delegated authority of the procedure(s) that will be used to determine compliance. Notification of the procedure(s) to be used must be postmarked at least 30 days prior to the performance test.

(c) For the purpose of this subpart, the owner or operator shall conduct the demonstration of compliance with § 60.272(a) of this subpart and furnish the Administrator or delegated authority with a written report of the results of the test. This report shall include the following information:

* * * * *

(3) Make and model of the control device, and continuous opacity monitoring equipment, if applicable;

(4) Flow diagram of process and emission capture system including other equipment or process(es) ducted to the same control device;

* * * * *

(6) * * *

(iv) Continuous opacity monitor or EPA Method 9 data, or, as an alternative to EPA Method 9, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271.

* * * * *

(10) Test observers from any outside agency;

* * * * *

(d) The owner or operator shall maintain records of all shop opacity observations made in accordance with § 60.273(d). All shop opacity observations in excess of the emission limit specified in § 60.272(a)(3) of this subpart shall indicate a period of excess emissions, and shall be reported to the Administrator or delegated authority semi-annually, according to § 60.7(c) and submitted according to paragraph (h) of this section. In addition to the information required at § 60.7(c), the report shall include the following information:

(1) The company name and address of the affected facility.

(2) An identification of each affected facility being included in the report.

(3) Beginning and ending dates of the reporting period.

(4) A certification by a certifying official of truth, accuracy, and completeness. This certification shall

state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(e) * * *

(3) An identification of the date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, if procedures were initiated within 1 hour of the alarm, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and if the alarm was alleviated within 24 hours of the alarm.

(f) Records of the measurements required in § 60.274 must be retained for at least 5 years following the date of the measurement.

(g) Within 60 days after the date of completing each performance test or demonstration of compliance required by this subpart, you must submit the results of the performance test following the procedures specified in paragraphs (g)(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 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.

(3) Confidential business information (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) or (2) 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. The preferred method to submit CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (*e.g.,* Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and should include clear CBI markings and note the docket ID. 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. If sending CBI information through the postal service, 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 (g)(1) and (2) 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) You must submit a report of excess emissions and monitoring systems performance report according to § 60.7(c) to the Administrator semiannually. Submit all 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, follow paragraph (g)(3) of this section except send to the attention of the Electric Arc Furnace Sector Lead. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (h). 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.

(i) 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 (i)(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.

(j) 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 (j)(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.

(k) 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.

Subpart AAa—Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarbonization Vessels Constructed After August 17, 1983 and On or Before May 16, 2022

■ 10. Section 60.270a is amended by revising paragraph (b) to read as follows:

§ 60.270a Applicability and designation of affected facility.

* * * * *

(b) The provisions of this subpart apply to each affected facility identified in paragraph (a) of this section that commences construction, modification, or reconstruction after August 17, 1983 and on or before May 16, 2022, where a modification is any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which this standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which this standard applies) into the atmosphere not previously emitted.

■ 11. Section 60.271a is amended by:

■ a. Revising definitions for ''capture system'' and ''charge'';

■ b. Adding in alphabetical order the definition for ''Charging period'' and ''Damper'';

■ c. Revising the definitions for ''Direct-shell evacuation control system (DEC system),'' ''Dust-handling system'', ''Electric arc furnace (EAF)'', ''Heat cycle'', ''Meltdown and refining period'', ''Refining'', ''Shop'', and ''Shop opacity''.

The revisions and additions read as follows:

§ 60.271a Definitions.

* * * * *

Capture system means the equipment (including ducts, hoods, fans, dampers, etc.) used to capture particulate matter generated by the operation of an electric arc furnace or AOD vessel and transport captured particulate matter to the air pollution control device.

Charge means the addition of iron and steel scrap or other materials into the shell of an electric arc furnace or the addition of molten steel or other materials into the top of an AOD vessel.

Charging period means the time period when iron and steel scrap or other materials are added into the top of an electric arc furnace until the melting and refining period commences.

* * * * *

Damper means any device used to open, close or throttle a DEC system or hood designed to capture emissions from an EAF or AOD vessel and route them to the associated control device(s). It does not include isolation dampers used to isolate a fan or baghouse compartment for repair or cleaning, or dampers controlling collection of emissions from equipment other than an EAF or AOD vessel.

Direct-shell evacuation control system (DEC system) means a system that creates and maintains a negative pressure within the electric arc furnace shell during melting and refining, and transports emissions to the control device.

Dust-handling system means equipment used to handle particulate matter collected by the control device for an electric arc furnace or AOD vessel subject to this subpart. For the purposes of this subpart, the dust-handling system shall consist of the control device dust hoppers, the dust-conveying equipment, any silo, dust storage equipment, the dust-treating equipment (*e.g.,* pug mill, pelletizer), dust transfer equipment (including, but not limited to transfers from a silo to a truck or rail car), and any secondary control devices used with the dust transfer equipment.

Electric arc furnace (EAF) means a furnace that produces molten steel and heats the charge materials with electricity using-carbon electrodes. For the purposes of this subpart, an EAF shall consist of the furnace shell and roof and the transformer. Furnaces that continuously feed direct-reduced iron ore pellets as the primary source of iron are not affected facilities within the scope of this definition.

Heat cycle means the period beginning when scrap is charged to an EAF shell and ending when the EAF tap is completed or beginning when molten steel is charged to an AOD vessel and ending when the AOD vessel tap is completed.

Melting and refining period means the time period commencing at the initial energizing of the electrode to begin the melting process and ending at the initiation of the tapping period, excluding any intermediate times when the electrodes are not energized as part of the melting process.

* * * * *

Refining means that phase of the steel production cycle during which impurities are removed from the molten steel and alloys are added to reach the final metal chemistry.

Shop means the building that houses one or more EAF's or AOD vessels and serves as the point from which compliance with § 60.272a(a)(3), ''Standard for Particulate Matter,'' is measured.

Shop opacity means the arithmetic average of 24 observations of the opacity of any EAF or AOD emissions emanating from, and not within, the shop, taken in accordance with EPA Method 9 of appendix A of this part. Alternatively, ASTM D7520–16 (incorporated by reference, see § 60.17), may be used with the following five conditions:

(1) During the digital camera opacity technique (DCOT) certification procedure outlined in Section 9.2 of ASTM D7520–16 (incorporated by reference, see § 60.17), the owner or operator 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) 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 § 60.17);

(3) The owner or operator must follow the recordkeeping procedures outlined in § 60.7(f) for the DCOT certification, compliance report, data sheets, and all raw unaltered JPEGs used for opacity and certification determination;

(4) 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 anyone reading and the average error must not exceed 7.5 percent opacity;

(5) 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 § 60.17) and these requirements is on the facility, DCOT operator, and DCOT vendor.

* * * * *

■ 12. Revise § 60.272a to read as follows:

§ 60.272a Standard for particulate matter.

(a) On and after the date of which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from an EAF or an AOD vessel any gases which:

(1) Exit from a control device and contain particulate matter in excess of 12 mg/dscm (0.0052 gr/dscf);

(2) Exit from a control device and exhibit 3 percent opacity or greater, as measured in accordance with EPA Method 9 of appendix A of this part, or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271; and

(3) Exit from a shop and, due solely to the operations of any affected EAF(s) or AOD vessel(s), exhibit 6 percent opacity or greater, as measured in accordance with EPA Method 9 of appendix A of this part, or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271. Shop opacity shall be recorded for any point(s) where visible emissions are observed. Where it is possible to determine that a number of visible emission sites relate to only one incident of visible emissions, only one observation of shop opacity will be required. In this case, the shop opacity observations must be made for the site of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from the dust-handling system any gases that exhibit 10 percent opacity or greater, as measured in accordance with EPA Method 9 of appendix A of this part, or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271.

■ 13. Section 60.273a is amended by:

■ a. Revising paragraphs (c), (d), (e) introductory text, (e)(3);

■ b. In paragraph (e)(4) introductory text, remove the text ''the U.S. Environmental Protection Agency guidance document ''Fabric Filter Bag Leak Detection Guidance'' (EPA–454/R–98–015)'' and add, in its place, the text ''EPA–454/R–98–015, Fabric Filter Bag Leak Detection Guidance (incorporated by reference, see § 60.17)'';

■ c. Revising paragraphs (e)(6)(i) and (ii), (e)(7), (f) introductory text, (f)(1) and(5);

■ d. Redesignating paragraph (f)(6) as paragraph (f)(7);

■ e. Adding new paragraph (f)(6); and

■ f. Revising paragraph (g).

The revisions and addition read as follows:

§ 60.273a Emission monitoring.

* * * * *

(c) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the control device(s) is not required on any modular, multi-stack, negative-pressure or positive-pressure fabric filter or on any single-stack fabric filter if observations of the opacity of the visible emissions from the control device are performed by a certified visible emission observer and the owner installs and operates a bag leak detection system according to paragraph (e) of this section whenever the control device is being used to remove particulate matter from the EAF or AOD. Visible emission observations shall be conducted at least once per day of the control device for at least three 6-minute periods when the furnace is operating in the melting and refining period. All visible emissions observations shall be conducted in accordance with EPA Method 9, or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271. If visible emissions occur from more than one point, the opacity shall be recorded for any points where visible emissions are observed. Where it is possible to determine that a number of visible emission points relate to only one incident of the visible emission, only one set of three 6-minute observations will be required. In that case, the EPA Method 9 observations must be made for the point of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident. Records shall be maintained of any 6-minute average that is in excess of the emission limit specified in § 60.272a(a)(2).

(d) A furnace static pressure monitoring device is not required on any EAF equipped with a DEC system if observations of shop opacity are performed by a certified visible emission observer as follows:

(1) At least once per day when the furnace is operating.

(2) No less than once per week, commencing from the tap of one EAF heat cycle to the tap of the following heat cycle. A melt shop with more than one EAF shall conduct these readings while both EAFs are in operation. Both EAFs are not required to be on the same schedule for tapping.

(3) Shop opacity shall be determined as the arithmetic average of 24 consecutive 15-second opacity observations of emissions from the shop taken in accordance with EPA Method 9, or, as an alternative, according to

ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271. Shop opacity shall be recorded for any point(s) where visible emissions are observed. Where it is possible to determine that a number of visible emission points relate to only one incident of visible emissions, only one observation of shop opacity will be required. In this case, the shop opacity observations must be made for the point of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident.

(e) A bag leak detection system must be installed on all single-stack fabric filters and operated whenever the control device is being used to remove particulate matter from the EAF or AOD vessel if the owner or operator elects not to install and operate a continuous opacity monitoring system as provided for under paragraph (c) of this section. In addition, the owner or operator shall meet the visible emissions observation requirements in paragraph (c) of this section. The bag leak detection system must meet the specifications and requirements of paragraphs (e)(1) through (8) of this section.

* * * * *

(3) The bag leak detection system must be equipped with an alarm system that will activate when an increase in relative particulate loading is detected over the alarm set point established according to paragraph (e)(4) of this section, and the alarm must be located such that it can be identified by the appropriate plant personnel.

* * * * *

(6) * * *

(i) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects including temperature and humidity according to the procedures identified in the site-specific monitoring plan required under paragraph (e)(4) of this section.

(ii) If opacities greater than zero percent are observed over four consecutive 15-second observations during the daily opacity observations required under paragraph (c) of this section and the alarm on the bag leak detection system alarm is not activated, the owner or operator shall lower the alarm set point on the bag leak detection system to a point where the alarm would have been activated during the period when the opacity observations were made.

(7) For negative pressure, induced air baghouses, and positive pressure baghouses that are discharged to the atmosphere through a stack, the bag leak detection sensor must be installed downstream of the baghouse or upstream of any wet scrubber.

* * * * *

(f) For each bag leak detection system installed according to paragraph (e) of this section, the owner or operator shall initiate procedures to determine the cause of all alarms within 1 hour of an alarm. The cause of the alarm must be alleviated within 24 hours of the time the alarm occurred by taking whatever response action(s) are necessary. Response actions may include, but are not limited to, the following:

(1) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may have caused an increase in particulate emissions;

* * * * *

(5) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system;

(6) Establishing to the extent acceptable by the delegated authority that the alarm was a false alarm and not caused by a bag leak or other malfunction that could reasonably result in excess particulate emissions; and

* * * * *

(g) In approving the site-specific monitoring plan required in paragraph (e)(4) of this section, the Administrator or delegated authority may allow owners or operators more than 24 hours to alleviate specific conditions that cause an alarm if the owner or operator identifies the condition that could lead to an alarm in the monitoring plan, adequately explains why it is not feasible to alleviate the condition within 24 hours of the time the alarm occurred, and demonstrates that the requested additional time will ensure alleviation of the condition as expeditiously as practicable.

■ 14. Section 60.274a is amended by revising paragraphs (b) through (h) to read as follows:

§ 60.274a Monitoring of operations.

* * * * *

(b) Except as provided under paragraph (e) of this section, the owner or operator subject to the provisions of this subpart shall:

(1) Monitor and record on a continuous basis the rolling 15-minute average furnace static pressure (if a DEC system is in use, and a furnace static pressure gauge is installed according to paragraph (f) of this section) and either:

(i) Install, calibrate, and maintain a monitoring device that continuously records the capture system fan motor amperes and damper position(s);

(ii) Install, calibrate, and maintain a monitoring device that continuously records on a rolling 15-minute average basis either the volumetric flow rate through each separately ducted hood; or

(iii) Install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate at the control device inlet continuously record damper positions(s).

(2) The volumetric flow monitoring device(s) may be installed in any appropriate location in the capture system such that reproducible flow rate monitoring will result. The flow rate monitoring device(s) shall have an accuracy of ±10 percent over its normal operating range and shall be calibrated according to the manufacturer's instructions. The Administrator may require the owner or operator to demonstrate the accuracy of the monitoring device(s) relative to EPA Methods 1 and 2 of appendix A of this part.

(3) Parameters monitored pursuant to this paragraph, excluding damper position, shall be recorded on a rolling averaging period not to exceed 15 minutes.

(c) When the owner or operator of an affected facility is required to demonstrate compliance with the standards under § 60.272a(a)(3) and at any other time that the Administrator may require (under section 114 of the CAA, as amended), the owner or operator shall determine during periods in which a hood is operated for the purpose of capturing emissions from the affected facility subject to paragraph (b) of this section, all damper positions and either the:

(1) Monitor and record the fan motor amperes at each damper position, and damper position consistent with paragraph (h)(5) of this section;

(2) Install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate through each separately ducted hood; or

(3) Install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate at the control device inlet and monitor and record the damper position consistent with paragraph (h)(5) of this section.

(4) Parameters monitored pursuant to this paragraph, excluding damper position, shall be recorded on a rolling averaging period not to exceed 15 minutes.

(5) The owner or operator may petition the Administrator or delegated authority for reestablishment of these parameters whenever the owner or operator can demonstrate to the Administrator's or delegated authority's satisfaction that the affected facility

operating conditions upon which the parameters were previously established are no longer applicable. The values of the parameters as determined during the most recent demonstration of compliance shall be the appropriate operational range or control set point throughout each applicable period. Operation at values beyond the accepted operational range or control set point may be subject to the requirements of § 60.276a(c).

(d) Except as provided under paragraph (e) of this section, the owner or operator shall perform monthly operational status inspections of the equipment that is important to the performance of the capture system (*i.e.,* pressure sensors, dampers, and damper switches). This inspection shall include observations of the physical appearance of the equipment (*e.g.,* presence of holes in ductwork or hoods, flow constrictions caused by dents or excess accumulations of dust in ductwork, and fan erosion) and building inspections to ensure that the building does not have any holes or other openings for particulate matter laden air to escape. Any deficiencies that are determined by the operator to materially impact the efficacy of the capture system shall be noted and proper maintenance performed.

(e) The owner or operator may petition the Administrator or delegated authority to approve any alternative to either the monitoring requirements specified in paragraph (b) of this section or the monthly operational status inspections specified in paragraph (d) of this section if the alternative will provide a continuous record of operation of each emission capture system.

(f) Except as provided for under § 60.273a(d), if emissions during any phase of the heat cycle are controlled by the use of a DEC system, the owner or operator shall install, calibrate, and maintain a monitoring device that allows the pressure in the free space inside the EAF to be monitored. The pressure shall be recorded as no greater than 15-minute integrated block averages. The monitoring device may be installed in any appropriate location in the EAF or DEC duct prior to the introduction of ambient air such that reproducible results will be obtained. The pressure monitoring device shall have an accuracy of ±5 mm of water gauge over its normal operating range and shall be calibrated according to the manufacturer's instructions.

(g) Except as provided for under § 60.273a(d), when the owner or operator of an EAF controlled by a DEC is required to demonstrate compliance with the standard under § 60.272a(a)(3), and at any other time the Administrator may require (under section 114 of the Clean Air Act, as amended), the pressure in the free space inside the furnace shall be determined during the melting and refining period(s) using the monitoring device required under paragraph (f) of this section. The owner or operator may petition the Administrator or delegated authority for reestablishment of the pressure whenever the owner or operator can demonstrate to the Administrator's or delegated authority's satisfaction that the EAF operating conditions upon which the pressures were previously established are no longer applicable. The pressure range or control setting during the most recent demonstration of compliance shall be maintained at all times when the EAF is operating in a melting and refining period. Continuous operation at pressures higher than the operational range or control setting may be considered by the Administrator or delegated authority to be unacceptable operation and maintenance of the affected facility.

(h) During any performance test required under § 60.8, and for any report thereof required by § 60.276a(f) of this subpart, or to determine compliance with § 60.272a(a)(3) of this subpart, the owner or operator shall monitor the following information for all heats covered by the test:

(1) Charge weights and materials, and tap weights and materials;

(2) Heat times, including start and stop times, and a log of process operation, including periods of no operation during testing and, if a furnace static pressure monitoring device is operated pursuant to paragraph (f) of this section, the pressure inside an EAF when DEC systems are used;

(3) Control device operation log;

(4) Continuous opacity monitor or EPA Method 9 data, or, as an alternative to EPA Method 9, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271;

(5) All damper positions, no less frequently than performed in the latest melt shop opacity compliance test for a full heat, if selected as a method to demonstrate compliance under paragraph (b) of this section;

(6) Fan motor amperes at each damper position, if selected as a method to demonstrate compliance under paragraph (b) of this section;

(7) Volumetric air flow rate through each separately ducted hood, if selected as a method to demonstrate compliance under paragraph (b) of this section; and

(8) Static pressure at each separately ducted hood, if selected as a method to demonstrate compliance under paragraph (b) of this section.

(9) Parameters monitored pursuant to paragraphs (h)(6) through (8) of this section shall be recorded on a rolling averaging period not to exceed 15 minutes.

■ 15. Section 60.275a is amended by:

■ a. Revising paragraphs (a) and (b)(2);

■ b. Adding paragraph (b)(3);

■ c. Revising paragraphs (c) and (e);

■ d. Removing paragraph (h);

■ e. Redesignating paragraphs (i) and (j) as paragraphs (h) and (i) and revising the newly redesignated paragraph (h).

The revisions and addition read as follows:

§ 60.275a Test methods and procedures.

(a) During performance tests required in § 60.8, the owner or operator shall not add gaseous diluents to the effluent gas stream after the fabric filter in any pressurized fabric filter collector, unless the amount of dilution is separately determined and considered in the determination of emissions.

(b) * * *

(2) Use a method that is acceptable to the Administrator or delegated authority and that compensates for the emissions from the facilities not subject to the provisions of this subpart.

(3) Any combination of the criteria of paragraphs (b)(1) and (b)(2) of this section.

(c) When emission from any EAF(s) or AOD vessel(s) are combined with emissions from facilities not subject to the provisions of this subpart, compliance with § 60.272a(a)(3) will be based on emissions from only the affected facility(ies). The owner or operator may use operational knowledge to determine the facilities that are the sources, in whole or in part, of any emissions observed in demonstrations of compliance with § 60.272a(a)(3).

* * * * *

(e) The owner or operator shall determine compliance with the particulate matter standards in § 60.272a as follows:

(1) EPA Method 5 (and referenced EPA Methods 1, 2, 3, 3A, 3B, and 4) shall be used for negative-pressure fabric filters and other types of control devices and EPA Method 5D (and referenced EPA Method 5) shall be used for positive-pressure fabric filters to determine the particulate matter concentration and volumetric flow rate of the effluent gas. The sampling time and sample volume for each run shall be at least 4 hours and 4.50 dscm (160 dscf) and, when a single EAF or AOD vessel

is sampled, the sampling time shall include an integral number of heats. The manual portions only and not the instrumental portion of the voluntary consensus standard ANSI/ASME PTC 19.10–1981 (incorporated by reference, see § 60.17) is an acceptable alternative to EPA Methods 3, 3A, and 3B.

(2) When more than one control device serves the EAF(s) being tested, the concentration of particulate matter shall be determined using the following equation:

$$c_{st} = \left[\sum_{i=1}^{n} \left(c_{si} Q_{sdi} \right) \right] / \sum_{i=1}^{n} Q_{sdi}$$

Where:

c_{st} = average concentration of particulate matter, mg/dscm (gr/dscf).

c_{si} = concentration of particulate matter from control device ''i'', mg/dscm (gr/dscf).

n = total number of control devices tested.

Q_{sdi} = volumetric flow rate of stack gas from control device ''i'', dscm/hr (dscf/hr).

(3) EPA Method 9 or, as an alternative, ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271, and the procedures of § 60.11 shall be used to determine opacity.

(4) To demonstrate compliance with § 60.272a(a) (1), (2), and (3), the EPA Method 9 test runs shall be conducted concurrently with the particulate matter test runs, unless inclement weather interferes.

* * * * *

(h) Where emissions from any EAF(s) or AOD vessel(s) are combined with emissions from facilities not subject to the provisions of this subpart, determinations of compliance with § 60.272a(a)(3) will only be based upon emissions originating from the affected facility(ies), except if the combined emissions are controlled by a common capture system and control device, in which case the owner or operator may use any of the following procedures during an opacity performance test and during shop opacity observations:

(1) Base compliance on control of the combined emissions; or

(2) Utilize a method acceptable to the Administrator that compensates for the emissions from the facilities not subject to the provisions of this subpart.

(i) Unless the presence of inclement weather makes concurrent testing infeasible, the owner or operator shall conduct concurrently the performance tests required under § 60.8 to demonstrate compliance with § 60.272a(a) (1), (2), and (3) of this subpart.

■ 16. Section 60.276a is amended by:

■ a. Revising paragraphs (a) through (c), (e), (f) introductory text, (f)(3) and (4), (6)(iv), (10), (g), and (h)(3); and

■ b. Adding new paragraphs (i) through (m).

The revisions and additions read as follows:

§ 60.276a Recordkeeping and reporting requirements.

(a) Records of the measurements required in § 60.274a must be retained for at least 5 years following the date of the measurement.

(b) Each owner or operator shall submit a written report of exceedances of the control device opacity to the Administrator or delegated authority semi-annually. For the purposes of these reports, exceedances are defined as all 6-minute periods during which the average opacity of emissions from the control device is 3 percent or greater.

(c) Continuous operation at a furnace static pressure that exceeds the operational range or control setting under § 60.274a(g), for owners and operators that elect to install a furnace static pressure monitoring device under § 60.274a(f) or operation at flow rates lower than those established under § 60.274a(c) may be considered by the Administrator or delegated authority to be unacceptable operation and maintenance of the affected facility. Operation at such values shall be reported to the Administrator or delegated authority semiannually.

* * * * *

(e) When the owner or operator of an EAF or AOD is required to demonstrate compliance with the standard under § 60.275a(b)(2) or a combination of § 60.275a(b)(1) and (b)(2) the owner or operator shall provide notice to the Administrator or delegated authority of the procedure(s) that will be used to determine compliance. Notification of the procedure(s) to be used must be postmarked at least 30 days prior to the performance test.

(f) For the purpose of this subpart, the owner or operator shall conduct the demonstration of compliance with § 60.272a(a) of this subpart and furnish the Administrator or delegated authority with a written report of the results of the test. This report shall include the following information:

* * * * *

(3) Make and model of the control device, and continuous opacity monitoring equipment, if applicable;

(4) Flow diagram of process and emission capture system including other equipment or process(es) ducted to the same control device;

* * * * *

(6) * * *

(iv) Continuous opacity monitor or EPA Method 9 data, or, as an alternative to EPA Method 9, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271.

* * * * *

(10) Test observers from any outside agency;

* * * * *

(g) The owner or operator shall maintain records of all shop opacity observations made in accordance with § 60.273a(d). All shop opacity observations in excess of the emission limit specified in § 60.272a(a)(3) of this subpart shall indicate a period of excess emissions and shall be reported to the Administrator or delegated authority semi-annually, according to § 60.7(c) and submitted according to paragraph (j) of this section. In addition to the information required at § 60.7(c), the report shall include the following information:

(1) The company name and address of the affected facility.

(2) An identification of each affected facility being included in the report.

(3) Beginning and ending dates of the reporting period.

(4) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(h) * * *

(3) An identification of the date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, if procedures were initiated within 1 hour of the alarm, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and if the alarm was alleviated within 24 hours of the alarm.

(i) Within 60 days after the date of completing each performance test or demonstration of compliance required by this subpart, you must submit the results of the performance test following the procedures specified in paragraphs (i)(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 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.

(3) Confidential business information (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 (i)(1) or (2) 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. The preferred method to submit CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (*e.g.,* Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and should include clear CBI markings and note the docket ID. 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. If sending CBI information through the postal service, 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 (i)(1) and (2) 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.

(j) You must submit a report of excess emissions and monitoring systems performance report according to § 60.7(c) to the Administrator semiannually. Submit all 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, follow paragraph (i)(3) of this section except send to the attention of the Electric Arc Furnace Sector Lead. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (j). 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.

(k) 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 (k)(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.

(l) 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 (l)(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.

(m) 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.

■ 17. Add subpart AAb to part 60 to read as follows:

Subpart AAb—Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarbonization Vessels Constructed After May 16, 2022

§ 60.270b Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in steel plants that produce carbon, alloy, or specialty steels: electric arc furnaces (EAF), argon-oxygen decarburization (AOD) vessels, and dust-handling systems.

(b) The provisions of this subpart apply to each affected facility identified in paragraph (a) of this section that commences construction, modification, or reconstruction after May 16, 2022.

§ 60.271b Definitions

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

Argon-oxygen decarburization vessel (AOD vessel) means any closed-bottom, refractory-lined converter vessel with submerged tuyeres through which gaseous mixtures containing argon and oxygen or nitrogen may be blown into molten steel for further refining.

Bag leak detection system means a system that is capable of continuously monitoring relative particulate matter (dust) loadings in the exhaust of a baghouse to detect bag leaks and other conditions that result in increases in particulate loadings. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, electrodynamic, light scattering, light transmittance, or other effect to continuously monitor relative particulate matter loadings.

Capture system means the equipment (including ducts, hoods, fans, dampers, etc.) used to capture particulate matter generated by the operation of an electric arc furnace (EAF) or AOD vessel and transport captured particulate matter to the air pollution control device.

Charge means the addition of iron and steel scrap or other materials into the shell of an EAF or the addition of molten steel or other materials into the top of an AOD vessel.

Charging period means the time period when iron and steel scrap or other materials are added into the top of an EAF until the melting and refining period commences.

Control device means the air pollution control equipment used to remove particulate matter from the effluent gas stream generated by an EAF or AOD vessel.

Damper means any device used to open, close or throttle a DEC system or hood designed to capture emissions from an EAF or AOD vessel and route them to the associated control device(s). It does not include isolation dampers used to isolate a fan or baghouse compartment for repair or cleaning, or dampers controlling collection of emissions from equipment other than an EAF or AOD vessel.

Direct-shell evacuation control system (DEC system) means a system that designed to create and maintain a negative pressure within the EAF shell during melting and refining, and transports emissions to the control device.

Dust-handling system means equipment used to handle particulate matter collected by the control device for an EAF or AOD vessel subject to this subpart. For the purposes of this subpart, the dust-handling system shall consist of the control device dust hoppers, the dust-conveying equipment, any silo, dust storage equipment, the dust-treating equipment (*e.g.,* pug mill, pelletizer), dust transfer equipment (including, but not limited to transfers from a silo to a truck or rail car), and any secondary control devices used with the dust transfer equipment.

Electric arc furnace (EAF) means a furnace that produces molten steel and heats the charge materials with electricity using-carbon electrodes. For the purposes of this subpart, an EAF shall consist of the furnace shell and roof and the transformer. Furnaces that continuously feed direct-reduced iron ore pellets as the primary source of iron are not affected facilities within the scope of this definition.

Electric arc furnace facility means the EAF(s) or AOD(s) subject to this rule and the air pollution control equipment used to remove particulate matter from the effluent gas stream generated by the EAF(s) or AOD(s).

Furnace static pressure means the pressure exerted by the flow of air at the walls of the furnace, perpendicular to the flow, measured using a manometer or equivalent device to determine pressure inside an EAF when DEC systems are used or pressure in the free space inside the EAF.

Heat cycle means the period beginning when scrap is charged to an EAF shell and ending when the EAF tap is completed or beginning when molten steel is charged to an AOD vessel and ending when the AOD vessel tap is completed.

Melting means that phase of steel production cycle during which the iron and steel scrap is heated to the molten state.

Melting and refining period means the time period commencing at the initial energizing of the electrode to begin the melting process and ending at the initiation of the tapping period, excluding any intermediate times when the electrodes are not energized as part of the melting process.

Modified facility means any physical or operational change to an existing facility which results in an increase in the emission rate (in kilograms per hour) to the atmosphere of any pollutant to which a standard applies. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere. See § 60.14.

Negative-pressure fabric filter means a fabric filter with the fans on the downstream side of the filter bags.

Positive-pressure fabric filter means a fabric filter with the fans on the upstream side of the filter bags.

Reconstructed facility means an existing facility which upon reconstruction becomes an affected facility, irrespective of any change in emission rate, due to the replacement of components of an existing facility to such an extent that the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, where ''fixed capital cost'' means the capital needed to provide all the depreciable components, and it is technologically and economically feasible to meet the applicable standards set forth in this subpart after reconstruction.

Refining means that phase of the steel production cycle during which impurities are removed from the molten steel and alloys are added to reach the final metal chemistry.

Shop means the building that houses one or more EAF's or AOD vessels and serves as the point from which compliance with § 60.272b(a)(3), ''Standard for Particulate Matter,'' is measured.

Shop opacity means the arithmetic average of 24 observations of the opacity of any EAF or AOD emissions emanating from, and not within, the shop, during melting and refining, and during tapping, taken in accordance with EPA Method 9 of appendix A of this part, and during charging, according to the procedures in section 2.5 of Method 9 in appendix A to part 60 of this chapter, with the modification to determine the 3-minute block average opacity from the average of 12 consecutive observations recorded at 15-second intervals. For the daily opacity observation during melting and refining, during charging, and during tapping, facilities may measure opacity by EPA Method 22 of appendix A of this part, modified to require the recording of the aggregate duration of visible emissions at 15 second intervals. Alternatively, ASTM D7520–16 (incorporated by reference, see § 60.17), may be used with the following five conditions:

(1) During the digital camera opacity technique (DCOT) certification procedure outlined in Section 9.2 of ASTM D7520–16 (incorporated by reference, see § 60.17), the owner or operator 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) 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 § 60.17);

(3) The owner or operator must follow the recordkeeping procedures outlined in § 60.7(f) for the DCOT certification, compliance report, data sheets, and all raw unaltered JPEGs used for opacity and certification determination;

(4) 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 anyone reading and the average error must not exceed 7.5 percent opacity;

(5) 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 § 60.17) and these requirements is on the facility, DCOT operator, and DCOT vendor.

Static pressure means the pressure exerted by the flow of air at the furnace walls, perpendicular to the flow, measured using a manometer or equivalent device. This refers to either furnace static pressure, or static pressure in air ducts, or pressure in the EAF capture system, *i.e.,* static pressure at each separately ducted hood]

Tap means the pouring of molten steel from an EAF or AOD vessel.

Tapping period means the time period commencing at the moment an EAF begins to pour molten steel and ending either three minutes after steel ceases to flow from an EAF, or six minutes after steel begins to flow, whichever is longer.

§ 60.272b Standard for particulate matter.

(a) On and after the date of which the performance tests required to be conducted by § 60.8 or § 60.272b(d) are completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from an EAF or an AOD vessel any gases which:

(1) Exit from control devices at the facility and contain particulate matter as a total for the facility in excess of 79 mg/kg steel produced (0.16 lb/ton steel produced) for the facility;

(2) Exit from a control device and exhibit 3 percent opacity or greater, as measured in accordance with EPA Method 9 of appendix A of this part, or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271; and

(3) Exit from a shop and, due solely to the operations of any affected EAF(s) or AOD vessel(s) during melting and refining exhibit greater than 0 percent opacity, and during charging exhibit greater than 6 percent opacity, as measured in accordance with EPA Method 9 of appendix A of this part, and during charging, exhibit greater than 6 percent opacity, as measured according to the procedures in section 2.5 of Method 9 in appendix A to part 60 of this chapter, with the modification of this section of Method 9 to determine the 3-minute block average opacity from the average of 12 consecutive observations recorded at 15-second intervals; or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271 or, for the daily opacity observations, exhibit 0 seconds of visible emissions as measured by EPA Method 22 of appendix A of this part, modified to require the recording of the aggregate duration of visible emissions at 15 second intervals. Shop opacity shall be recorded for any point(s) during melting and refining, during charging, and during tapping where visible emissions are observed. Where it is possible to determine that a number of visible emission sites relate to only one incident of visible emissions during melting and refining, during charging, or during tapping, only one observation of shop opacity or visible emissions will be required during melting and refining, during charging, or during tapping. In this case, the shop opacity or visible emissions observations must be made for the point of highest emissions during melting and refining, during charging, or during tapping that directly relates to the cause (or location) of visible emissions observed during a single incident.

(b) On and after the date on which the performance tests required to be conducted by § 60.8 or § 60.272b(d) are completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from the dust-handling system any gases that exhibit 10 percent opacity or greater, as measured in accordance with EPA Method 9 of appendix A of this part, or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271.

(c) The standards in paragraphs (a) and (b) apply at all times. The exemptions to opacity standards under § 60.11(c) do not apply to this subpart. As provided in § 60.11(f), this provision supersedes the exemptions for periods of startup, shutdown and malfunction in the Part 60 general provisions in Subpart A.

(d) Performance tests required to be conducted to show compliance with the standards in paragraph (a) of this section shall be repeated at least every 5 years after the performance tests required by § 60.8 are conducted.

§ 60.273b Emission monitoring

(a) Except as provided under paragraphs (b) and (c) of this section, a continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the control device(s) shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart.

(b) No continuous monitoring system shall be required on any control device serving the dust-handling system.

(c) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the control device(s) is not required on any modular, multi-stack, negative-pressure or positive-pressure fabric filter or on any single-stack fabric filter if observations of the opacity of the visible emissions from the control device are performed by a certified visible emission observer and the owner installs and operates a bag leak detection system according to paragraph (e) of this section whenever the control device is being used to remove particulate matter from the EAF or AOD. Visible emission observations shall be conducted at least once per day on the control device for at least three 6-minute periods when the furnace is operating in the melting and refining period. All visible emissions observations shall be conducted in accordance with EPA Method 9, or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271. If visible emissions occur from more than one point, the opacity shall be recorded for any points where visible emissions are observed. Where it is possible to determine that a number of visible emission points relate to only one incident of the visible emission, only one set of three 6-minute observations will be required. In that case, the EPA Method 9 observations must be made for the point of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident. Records shall be maintained of any 6-minute average that is in excess of the emission limit specified in § 60.272b(a)(2).

(d) A furnace static pressure monitoring device is not required on any EAF equipped with a DEC system if observations of shop opacity are performed by a certified visible emission observer as follows:

(1) At least once per day when the furnace is operating.

(2) No less than once per week, commencing from the tap of one EAF heat cycle to the tap of the following heat cycle. A melt shop with more than one EAF shall conduct these readings while both EAFs are in operation. Both EAFs are not required to be on the same schedule for tapping.

(3) Shop opacity shall be determined as the arithmetic average of 24 consecutive 15-second opacity observations of emissions from the shop taken in accordance with EPA Method 9 during melting and refining and during tapping; and during charging determined according to the procedures in section 2.5 of Method 9 in appendix A to part 60 of this chapter, with the modification to determine the 3-minute block average opacity from the average of 12 consecutive observations recorded at 15-second intervals; or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271, or as the total duration of visible emissions measured according to EPA Method 22 over a six minute period, modified to require the recording of the aggregate duration of visible emissions at 15 second intervals. Shop opacity shall be recorded for any point(s) where visible emissions are observed. Where it is possible to determine that a number of visible emission points relate to only one incident of visible emissions, only one observation of shop opacity will be required. In this case, the shop opacity observations must be made for the point of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident. Shop opacity shall be determined daily during melting and refining, during charging, and during tapping.

(e) A bag leak detection system must be installed on all fabric filters and operated on all single-stack fabric filters whenever the control device is being used to remove particulate matter from the EAF or AOD vessel if the owner or operator elects not to install and operate a continuous opacity monitoring system as provided for under paragraph (c) of this section. In addition, the owner or operator shall meet the visible emissions observation requirements in paragraph (c) of this section. The bag leak detection system must meet the specifications and requirements of paragraphs (e)(1) through (8) of this section.

(1) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at a concentrations of 1 milligram per actual cubic meter (0.00044 grains per actual cubic foot) or less.

(2) The bag leak detection system sensor must provide output of relative particulate matter loadings and the owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (*e.g.,* using a strip chart recorder or a data logger.)

(3) The bag leak detection system must be equipped with an alarm system that will activate when an increase in relative particulate loading is detected over the alarm set point established according to paragraph (e)(4) of this section, and the alarm must be located such that it can be identified by the appropriate plant personnel.

(4) For each bag leak detection system required by paragraph (e) of this section, the owner or operator shall develop and submit to the Administrator or delegated authority, for approval, a site-specific monitoring plan that addresses the items identified in paragraphs (i) through (v) of this paragraph (e)(4). For each bag leak detection system that operates based on the triboelectric effect, the monitoring plan shall be consistent with the recommendations contained in EPA–454/R–98–015, ''Fabric Filter Bag Leak Detection Guidance'' (incorporated by reference, see § 60.17). The owner or operator shall operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. The plan shall describe the following:

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system including quality assurance procedures;

(iv) How the bag leak detection system will be maintained including a routine maintenance schedule and spare parts inventory list; and

(v) How the bag leak detection system output shall be recorded and stored.

(5) The initial adjustment of the system shall, at a minimum, consist of establishing the baseline output by adjusting the sensitivity (range) and the averaging period of the device, and establishing the alarm set points and the alarm delay time (if applicable).

(6) Following initial adjustment, the owner or operator shall not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided for in paragraphs (e)(6)(i) and (ii) of this section.

(i) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects including temperature and humidity according to the procedures identified in the site-specific monitoring plan required under paragraph (e)(4) of this section.

(ii) If opacities greater than 0 percent are observed over four consecutive 15-second observations during the daily opacity observations required under paragraph (c) of this section and the alarm on the bag leak detection system alarm is not activated, the owner or operator shall lower the alarm set point on the bag leak detection system to a point where the alarm would have been activated during the period when the opacity observations were made.

(7) For negative pressure, induced air baghouses, and positive pressure baghouses that are discharged to the atmosphere through a stack, the bag leak detection sensor must be installed downstream of the baghouse or upstream of any wet scrubber.

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

(f) For each bag leak detection system installed according to paragraph (e) of this section, the owner or operator shall initiate procedures to determine the cause of all alarms within 1 hour of an alarm. The cause of the alarm must be alleviated within 24 hours of the time the alarm occurred by taking whatever response action(s) are necessary. Response actions may include, but are not limited to, the following:

(1) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may have caused an increase in particulate emissions;

(2) Sealing off defective bags or filter media;

(3) Replacing defective bags or filter media or otherwise repairing the control device;

(4) Sealing off a defective baghouse compartment;

(5) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system;

(6) Establishing to the extent acceptable by the delegated authority that the alarm was a false alarm and not caused by a bag leak or other malfunction that could reasonably result in excess particulate emissions; and

(7) Shutting down the process producing the particulate emissions.

(g) In approving the site-specific monitoring plan required in paragraph (e)(4) of this section, the Administrator or delegated authority may allow owners or operators more than 24 hours to alleviate specific conditions that cause an alarm if the owner or operator identifies the condition that could lead to an alarm in the monitoring plan, adequately explains why it is not feasible to alleviate the condition within 24 hours of the time the alarm occurred, and demonstrates that the requested additional time will ensure alleviation of the condition as expeditiously as practicable.

§ 60.274b Monitoring of operations.

(a) The owner or operator subject to the provisions of this subpart shall maintain records of the following information:

(1) All data obtained under paragraph (b) of this section; and

(2) All monthly operational status inspections performed under paragraph (c) of this section.

(b) Except as provided under paragraph (e) of this section, the owner or operator subject to the provisions of this subpart shall conduct the following monitoring of the capture system to demonstrate continuous compliance:

(1) If a DEC system is in use, according to paragraph (f) of this section, monitor and record on a continuous basis the furnace static pressure and any one of (2) through (4) in this paragraph:

(2) Monitor and record the fan motor amperes at each damper position, and damper position consistent with paragraph (h)(5) of this section;

(3) Install, calibrate, and maintain a monitoring device that continuously records the volumetric air flow rate or static pressure at each separately ducted hood; or

(4) Install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate at the control device inlet and monitor and record the damper position consistent with paragraph (h)(5) of this section.

(5) The static pressure monitoring device(s) shall be installed in an EAF or DEC duct prior to combining with other ducts and prior to the introduction of ambient air, at a location that has no flow disturbance due to the junctions.

(6) The volumetric flow monitoring device(s) may be installed in any appropriate location in the capture system such that reproducible flow rate monitoring will result. The flow rate monitoring device(s) shall have an accuracy of ±10 percent over its normal operating range and shall be calibrated according to the manufacturer's instructions. The Administrator may require the owner or operator to demonstrate the accuracy of the monitoring device(s) relative to EPA Methods 1 and 2 of appendix A of this part.

(7) Parameters monitored pursuant to this paragraph, excluding damper position, shall be recorded on a rolling averaging period not to exceed 15 minutes.

(c) When the owner or operator of an affected facility is required to demonstrate compliance with the standards under § 60.272b(a)(3) and at any other time that the Administrator may require (under section 114 of the CAA, as amended), the owner or operator shall determine during all periods in which a hood is operated for the purpose of capturing emissions from the affected facility subject to paragraph (b) of this section, either:

(1) Monitor and record the fan motor amperes at each damper position, and damper position consistent with paragraph (h)(5) of this section;

(2) install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate through each separately ducted hood; or

(3) install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate at the control device inlet and monitor and record the damper position consistent with paragraph (h)(5) of this section.

(4) Parameters monitored pursuant to this paragraph, excluding damper position, shall be recorded on a rolling averaging period not to exceed 15 minutes.

(5) The owner or operator may petition the Administrator or delegated authority for reestablishment of these parameters whenever the owner or operator can demonstrate to the Administrator's or delegated authority's satisfaction that the affected facility operating conditions upon which the parameters were previously established are no longer applicable. The values of the parameters as determined during the most recent demonstration of compliance shall be the appropriate operational range or control set point throughout each applicable period. Operation at values beyond the accepted operational range or control set point may be subject to the requirements of § 60.276b(c).

(d) Except as provided under paragraph (e) of this section, the owner or operator shall perform monthly operational status inspections of the equipment that is important to the performance of the capture system (*i.e.,* pressure sensors, dampers, and damper switches). This inspection shall include observations of the physical appearance of the equipment (*e.g.,* presence of holes in ductwork or hoods, flow constrictions caused by dents or excess accumulations of dust in ductwork, and fan erosion) and building inspections to ensure that the building does not have any holes or other openings for particulate matter laden air to escape. Any deficiencies that are determined by the operator to materially impact the efficacy of the capture system shall be noted and proper maintenance performed.

(e) The owner or operator may petition the Administrator or delegated authority to approve any alternative to either the monitoring requirements specified in paragraph (b) of this section or the monthly operational status inspections specified in paragraph (d) of this section if the alternative will provide a continuous record of operation of each emission capture system.

(f) Except as provided under § 60.273b(d), if emissions during any phase of the heat cycle are controlled by the use of a DEC system, the owner or operator shall install, calibrate, and maintain a monitoring device that allows the pressure in the free space inside the EAF to be monitored. The pressure shall be recorded as no greater than 15-minute integrated block averages. The monitoring device may be installed in any appropriate location in the EAF or DEC duct prior to the introduction of ambient air such that reproducible results will be obtained. The pressure monitoring device shall have an accuracy of ±5 mm of water gauge over its normal operating range and shall be calibrated according to the manufacturer's instructions.

(g) When the owner or operator of an EAF controlled by a DEC is required to demonstrate compliance with the standard under § 60.272b(a)(3), and at any other time the Administrator may require (under section 114 of the Clean Air Act, as amended), the pressure in the free space inside the furnace shall be determined during the melting and refining period(s) using the monitoring device required under paragraph (f) of this section. The owner or operator may petition the Administrator or delegated authority for reestablishment of the pressure whenever the owner or operator can demonstrate to the Administrator's or delegated authority's satisfaction that the EAF operating conditions upon which the pressures were previously established are no longer applicable. The pressure range or control setting during the most recent demonstration of compliance shall be maintained at all times when the EAF is operating in a melting and refining period. Continuous operation at pressures higher than the operational range or control setting may be considered by the Administrator or delegated authority to be unacceptable operation and maintenance of the affected facility.

(h) During any performance test required under § 60.8 or § 60.272b(d), and for any report thereof required by § 60.276b(f) of this subpart, or to determine compliance with § 60.272b(a)(3) of this subpart, the owner or operator shall monitor the following information for all heats covered by the test:

(1) Charge weights and materials, and tap weights and materials;

(2) Heat times, including start and stop times, and a log of process operation, including periods of no operation during testing and, if a furnace static pressure monitoring device is operated pursuant to paragraph (f) of this section, the pressure inside an EAF when DEC systems are used;

(3) Control device operation log;

(4) Continuous opacity monitor (COM) or EPA Method 9 data, or, as an alternative to EPA Method 9, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271;

(5) All damper positions, no less frequently than performed in the latest melt shop opacity compliance test for a full heat, if selected as a method to demonstrate compliance under paragraph (b) of this section;

(6) Fan motor amperes at each damper position, if selected as a method to demonstrate compliance under paragraph (b) of this section;

(7) Volumetric air flow rate through each separately ducted hood, if selected as a method to demonstrate compliance under paragraph (b) of this section; and

(8) Static pressure at each separately ducted hood, if selected as a method to demonstrate compliance under paragraph (b) of this section.

(9) Parameters monitored pursuant to paragraphs (h)(6)–(8) of this section shall be recorded on a rolling averaging period not to exceed 15 minutes.

§ 60.275b Test methods and procedures.

(a) During performance tests required in §§ 60.8 and 60.272b(d), the owner or operator shall not add gaseous diluents to the effluent gas stream after the fabric filter in any pressurized fabric filter collector, unless the amount of dilution is separately determined and considered in the determination of emissions.

(b) When emissions from any EAF(s) or AOD vessel(s) are combined with emissions from facilities not subject to the provisions of this subpart but controlled by a common capture system and control device, the owner or operator shall use any one of the following procedures during a performance test (see also § 60.276b(e)):

(1) Determine compliance using the combined emissions.

(2) Use a method that is acceptable to the Administrator or delegated authority and that compensates for the emissions from the facilities not subject to the provisions of this subpart.

(3) Any combination of the criteria of paragraphs (b)(1) and (2) of this section.

(c) When emission from any EAF(s) or AOD vessel(s) are combined with emissions from facilities not subject to the provisions of this subpart, compliance with § 60.272b(a)(3) will be based on emissions from only the affected facility(ies). The owner or operator may use operational knowledge to determine the facilities that are the sources, in whole or in part, of any emissions observed in demonstrations of compliance with § 60.272b(a)(3).

(d) In conducting the performance tests required in §§ 60.8 and 60.272b(d), the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(e) The owner or operator shall determine compliance with the particulate matter standards in § 60.272b as follows:

(1) EPA Method 5 (and referenced EPA Methods 1, 2, 3, 3A, 3B, and 4) shall be used for negative-pressure fabric filters and other types of control devices and EPA Method 5D (and referenced EPA Method 5) shall be used for positive-pressure fabric filters to determine the particulate matter concentration and volumetric flow rate of the effluent gas. The sampling time and sample volume for each run shall be at least 4 hours and 4.50 dry standard cubic meter (160 dry standard cubic feet) and, when a single EAF or AOD vessel is sampled, the sampling time shall include an integral number of heats. The manual portions only (not the instrumental portion) of the voluntary consensus standard ANSI/ASME PTC 19.10–1981 (incorporated by reference, see § 60.17) are acceptable alternatives to EPA Methods 3, 3A, and 3B.

(2) When more than one control device serves the EAF(s) being tested, the concentration of particulate matter shall be determined using the following equation:

$$E_{sf} = \sum_{i=1}^{n} \left(\frac{R_{si}}{P_i} \right)$$

where:

E_{sf} = average emission rate of particulate matter, mg/kg (lb/ton).

R_{si} = emission rate of particulate matter from control device ''i'', mg/hr (lb/hr).

n = total number of control devices at the facility.

P_i = steel production rate during testing of control device ''i'', kg/hr (ton/hr).

(3) EPA Method 9 or, as an alternative, ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271, and the procedures of § 60.11 shall be used to determine opacity.

(4) To demonstrate compliance with § 60.272b(a) (1), (2), and (3), the EPA Method 9 test runs shall be conducted concurrently with the particulate matter test runs, unless inclement weather interferes.

(f) To comply with § 60.274b(c), (f), (g), and (h), the owner or operator shall obtain the information required in these paragraphs during the particulate matter runs.

(g) Any control device subject to the provisions of the subpart shall be designed and constructed to allow measurement of emissions using applicable test methods and procedures.

(h) Where emissions from any EAF(s) or AOD vessel(s) are combined with emissions from facilities not subject to the provisions of this subpart, determinations of compliance with § 60.272b(a)(1), (2), and (3) will only be based upon emissions originating from the affected facility(ies), except if the combined emissions are controlled by a common capture system and control device, in which case the owner or operator may use any of the following procedures during an opacity performance test and during shop opacity observations:

(1) Base compliance on control of the combined emissions; or

(2) Utilize a method acceptable to the Administrator that compensates for the emissions from the facilities not subject to the provisions of this subpart.

(3) Any combination of the criteria of paragraphs (h)(1) and (2) of this section.

(i) Unless the presence of inclement weather makes concurrent testing infeasible, the owner or operator shall conduct concurrently the performance tests required under § 60.8 or § 60.272b(d) to demonstrate compliance with § 60.272b(a)(1), (2), and (3) of this subpart.

§ 60.276b Recordkeeping and reporting requirements.

(a) Records of the measurements required in § 60.274b must be retained for at least 5 years following the date of the measurement.

(b) Each owner or operator shall submit a written report of exceedances of the control device opacity to the Administrator or delegated authority semi-annually. For the purposes of these reports, exceedances are defined as all 6-minute periods during which the average opacity of emissions from the control device is 3 percent or greater or, where the daily shop opacity visible emissions were measured according to EPA Method 22 and exceeded 0 seconds.

(c) Operation at a furnace static pressure that exceeds the operational range or control setting under § 60.274b(g), for owners and operators that elect to install a furnace static pressure monitoring device under 60.274b(f) or operation ranges or control settings outside of those established under § 60.274b(c) may be considered by the Administrator or delegated authority to be unacceptable operation and maintenance of the affected facility. Operation at such values shall be reported to the Administrator or delegated authority semiannually.

(d) The requirements of this section remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with this section, provided that they comply with the requirements established by the State.

(e) When the owner or operator of an EAF or AOD is required to demonstrate compliance with the standard under § 60.275b(b)(2) or a combination of (b)(1) and (b)(2) the owner or operator provide notice to the Administrator or delegated authority of the procedure(s) that will be used to determine compliance. Notification of the procedure(s) to be used must be postmarked at least 30 days prior to the performance test.

(f) For the purpose of this subpart, the owner or operator shall conduct the demonstration of compliance with § 60.272b(a) of this subpart and furnish the Administrator or delegated authority with a report of the results of the test according to paragraph (i) of this section. This report shall include the following information:

(1) Facility name and address;

(2) Plant representative;

(3) Make and model of the control device, and continuous opacity monitoring equipment, if applicable;

(4) Flow diagram of process and emission capture system including other equipment or process(es) ducted to the same control device;

(5) Rated (design) capacity of process equipment;

(6) Those data required under § 60.274b(h) of this subpart;

(i) List of charge and tap weights and materials;

(ii) Heat times and process log;

(iii) Control device operation log; and

(iv) Continuous opacity monitor or EPA Method 9 data, or, as an alternative to EPA Method 9, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271.

(7) Test dates and test times;

(8) Test company;

(9) Test company representative;

(10) Test observers from any outside agency;

(11) Description of test methodology used, including any deviation from standard reference methods;

(12) Schematic of sampling location;

(13) Number of sampling points;

(14) Description of sampling equipment;

(15) Listing of sampling equipment calibrations and procedures;

(16) Field and laboratory data sheets;

(17) Description of sample recovery procedures;

(18) Sampling equipment leak check results;

(19) Description of quality assurance procedures;

(20) Description of analytical procedures;

(21) Notation of sample blank corrections; and

(22) Sample emission calculations.

(g) The owner or operator shall maintain records of all shop opacity observations made in accordance with § 60.273b(d). All shop opacity observations in excess of the emission limit specified in § 60.272b(a)(3) of this subpart shall indicate a period of excess emissions and shall be reported to the Administrator or delegated authority semi-annually, according to § 60.7(c) and submitted according to paragraph (j) of this section. In addition to the information required at § 60.7(c), the report shall include the following information:

(1) The company name and address of the affected facility.

(2) An identification of each affected facility being included in the report.

(3) Beginning and ending dates of the reporting period.

(4) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(h) The owner or operator shall maintain the following records for each bag leak detection system required under § 60.273b(e):

(1) Records of the bag leak detection system output;

(2) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(3) An identification of the date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, if procedures were initiated within 1 hour of the alarm, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and if the alarm was alleviated within 24 hours of the alarm.

(i) Within 60 days after the date of completing each performance test or demonstration of compliance required by this subpart, you must submit the results of the performance test following the procedures specified in paragraphs (i)(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 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.

(3) Confidential business information (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 (i)(1) or (2) 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. The preferred method to submit CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (*e.g.,* Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and should include clear CBI markings and note the docket ID. 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. If sending CBI information through the postal service, 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 (i)(1) and (2) 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.

(j) You must submit a report of excess emissions and monitoring systems performance report according to § 60.7(c) to the Administrator semiannually. Submit all 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, follow paragraph (i)(3) of this section except send to the attention of the Electric Arc Furnace Sector Lead. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (j). 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.

(k) 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 (k)(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.

(l) 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 (l)(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.

(m) 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.

[FR Doc. 2023–16747 Filed 8–24–23; 8:45 am]

BILLING CODE 6560–50–P

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TABLE 37 TO SUBPART D OF PART 161—DOCUMENTATION REQUIRED TO MODIFY A GENDER MARKER IN DEERS TO CORRECT AN ADMINISTRATIVE ERROR

Status	Documentation
Sponsor or Dependent	Birth certificate and FIPS Pub 201–3 "Personal Identity Verification (PIV) of Federal Employees and Contractors," Identity Proofing and Registration Requirements primary and secondary identity source documentation (Note).

Note: Documentation from the FIPS Pub 201–3, PIV Identity Proofing and Registration Requirements primary and secondary identity source document lists that establishes gender.

* * * * *

Dated: February 5, 2024.

Patricia Toppings,

OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2024–02621 Filed 2–13–24; 8:45 am]

BILLING CODE 6001–FR–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2002–0049; FRL–8150.1–03–OAR]

New Source Performance Standards Review for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels; Corrections

AGENCY: Environmental Protection Agency (EPA).

ACTION: Interim final rule; request for comment.

SUMMARY: The Environmental Protection Agency (EPA) is taking interim final action on corrections and clarifications to the new source performance standards (NSPS) for electric arc furnaces and argon-oxygen decarburization vessels in the steel industry. The corrections and clarifications are being made to address unintended and inadvertent errors in the recently finalized standards.

DATES: This interim final rule is effective on February 14, 2024. Comments on this rule must be received on or before March 15, 2024.

ADDRESSES: You may send comments, identified by Docket ID No. EPA–HQ–OAR–2002–0049 by any of the following methods:

- *Federal eRulemaking Portal: https://www.regulations.gov* (our preferred method). Follow the online instructions for submitting comments.
- *Email: a-and-r-docket@epa.gov.* Include Docket ID No. EPA–HQ–OAR–2002–0049 in the subject line of the message.
- *Fax:* (202) 566–9744. Attention Docket ID No. EPA–HQ–OAR–2002–0049.
- *Mail:* U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA–HQ–OAR–2002–0049, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- *Hand/Courier Delivery:* EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operation are 8:30 a.m.–4:30 p.m., Monday–Friday (except Federal Holidays).

Comments received may be posted without change to *https://www.regulations.gov,* including any personal information provided. For detailed instructions on sending comments, see the ''*Public Participation*'' heading of the General Information section of this document under **SUPPLEMENTARY INFORMATION.**

FOR FURTHER INFORMATION CONTACT: Donna Lee Jones, Sector Policies and Programs Division (D243–02), 109 T.W. Alexander Drive, P.O. Box 12055, Office of Air Quality Planning and Standards, United States Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5251; email address: *jones.donnalee@epa.gov.*

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:

AOD argon-oxygen decarburization
APA Administrative Procedure Act
BLDS bag leak detection system
CAA Clean Air Act
CBI confidential business information
CFR Code of Federal Regulations
CRA Congressional Review Act
DCOT during the digital camera opacity technique
DEC direct shell evacuation control
EAF electric arc furnace
EPA Environmental Protection Agency
FR Federal Register
FTP File Transfer Protocol
NAICS North American Industry Classification System
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement Act
OMB Office of Management and Budget
PM particulate matter
PRA Paperwork Reduction Act
RFA Regulatory Flexibility Act
UMRA Unfunded Mandates Reform Act of 1995
U.S. United States of America
U.S.C. United States Code

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

SUPPLEMENTARY INFORMATION:

I. General Information

A. Public Participation

Submit your written comments, identified by Docket ID No. EPA–HQ–OAR–2002–0049, at *https://www.regulations.gov* (our preferred method), or by the other methods identified in the **ADDRESSES** section. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit to the EPA's docket at *https://www.regulations.gov* any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. This type of information should be submitted as discussed in the *Submitting CBI* section of this document. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). Please visit *https://www.epa.gov/dockets/commenting-epa-dockets* for additional submission methods; the full EPA public comment policy; information about CBI or multimedia submissions; and general guidance on making effective comments.

Submitting CBI. Do not submit information containing CBI to the EPA through *https://www.regulations.gov.* Clearly mark the part or all of the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, note the docket ID, mark the outside of the digital storage media as CBI, and identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in the *Public Participation* section of this document. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI and note the docket ID. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2.

Our preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (*e.g.,* Dropbox, OneDrive, Google Drive). 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 note the docket ID. 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. If sending CBI information through the postal service, please send it to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055 RTP, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2002–0049. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

B. Potentially Affected Entities

The source category that is the subject of this interim final action is composed of steel manufacturing facilities that operate electric arc furnaces (EAF) and argon-oxygen decarburization (AOD) vessels regulated under CAA section 111 New Source Performance Standards (NSPS). The 2022 North American Industry Classification System (NAICS) code for the source category is 331110 for ''Iron and Steel Mills and Ferroalloy Manufacturing'' processes. The NAICS code serves as a guide for readers outlining the type of entities that this interim final action is likely to affect.

There are approximately 88 EAF facilities in the United States of America (U.S.), with most (>95 percent) EAF facilities subject to one of the EAF NSPS that are described below.

The information provided in this section on potentially affected entities is not intended to be exhaustive. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

C. Statutory Authority

Statutory authority to issue the amendments finalized in this action is provided by the same Clean Air Act (CAA) provisions that provided authority to issue the regulations being amended: CAA section 111(b)(1)(B) (requirement to review, and if appropriate, revise, NSPS standards at least every 8 years), and CAA section 301, 42 U.S.C. 7601 (general rulemaking authority). Statutory authority for the rulemaking procedures followed in this action is provided by Administrative Procedure Act (APA) section 553, 5 U.S.C. 553.

D. Judicial Review and Administrative Review

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 by April 15, 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.

II. Regulatory Revisions

A. Background and Summary

In 1975, the EPA first promulgated the EAF NSPS (subpart AA) to regulate emissions of particulate matter (PM) from new, reconstructed or modified EAF that produce steel. These standards apply to sources that commenced construction, modification, or reconstruction after October 21, 1974, and on or before August 17, 1983. In 1984, the EPA promulgated an updated EAF NSPS as subpart AAa, which revised the standards for EAF and also addressed AOD units. These standards apply to sources that commenced construction, modification or reconstruction after August 17, 1983, and on or before May 16, 2022. On August 25, 2023, the EPA promulgated amendments to the EAF NSPS (88 FR 58459), including a new NSPS subpart AAb that establishes standards applicable to units that are new, modified, or reconstructed after May 16, 2022, as well as certain amendments to NSPS subparts AA and AAa that are applicable to units that began construction or reconstruction by the earlier dates specified in those two subparts.

Relevant to this action, the 2023 final rule included the following: (1) a new NSPS subpart AAb which maintained the requirement for facilities to meet a shop opacity of six percent during charging [1]—the same as is required

[1] There are three stages of EAF operation, where one of the three stages is charging of raw materials (metal scrap) into the EAF. Charging typically occurs in periods of less than 1 minute to up to 3

Continued

under subparts AA and AAa; and required opacity testing to be performed once a day during charging for 3 minutes using EPA Method 9 in appendix A to part 60 of this chapter, from the average of 12 consecutive observations recorded at 15-second intervals; (2) a provision under subparts AA, AAa, and AAb that permits EAF, AOD, or both facilities with direct shell evacuation control (DEC) that want to avoid the requirement to use a furnace static pressure monitoring device to, as an alternative, perform observations of shop opacity no less than once per week from the end of one EAF heat cycle to the end of the following heat cycle (a heat cycle means the period beginning when scrap is charged to an EAF shell and ending when the EAF tap is completed or beginning when molten steel is charged to an AOD vessel and ending when the AOD vessel tap is completed); and (3) a compliance date for provisions applicable to facilities subject to subpart AA or AAa of February 21, 2024. The standards and requirements under subpart AAb were effective immediately upon publication of the final rule on August 25, 2023.

Following issuance of the final rule, the EPA was notified by industry representatives of several errors in the final regulatory text for subparts AA, AAa, and AAb. The American Iron and Steel Institute (''AISI''), the Steel Manufacturers Association (''SMA''), and the Specialty Steel Industry of North America (''SSINA'') (collectively, ''the Steel Associations'') submitted letters on August 17 and September 29, 2023, detailing concerns with the final rule, including certain new requirements in the final regulatory text, and requested corrections. In addition, on October 24, 2023, the Steel Associations submitted a petition for reconsideration and a request for an administrative stay pursuant to CAA section 307(d)(7)(B), identifying, among other issues, concerns with new requirements in the final regulatory text.[2]

This action addresses errors identified by the Steel Associations, which are described in the following paragraphs, as well as errors identified by the EPA. This action does not attempt to address all issues identified in the Steel Associations communications, as the EPA continues to review the other issues not directly addressed in this action. To the extent the EPA determines that additional action is appropriate to address these other issues, we will initiate a separate rulemaking action.

In the 2023 final rule, the EPA inadvertently included a requirement under subparts AA, AAa and AAb for observations of shop opacity to be performed by a certified visible emission observer no less than once per week for all EAF facilities subject to subparts AA, AAa or AAb, starting at the end of one EAF heat cycle and stopping at the end of the following heat cycle. The EPA never proposed nor intended to include such a requirement in the final rule. Because this requirement had not been included in the 2022 EAF NSPS proposed rule (87 FR 29710), the public did not have an opportunity to comment on this requirement, and the effects of the requirement were not included in the EPA's cost estimates or economic impact analysis for the 2023 final rule (88 FR 58459).

In addition, after the 2023 final rule was promulgated, the EPA discovered that the charging period associated with the finalized opacity testing requirement in NSPS subpart AAb, despite being the shortest operational period for an EAF, AOD or both, could be broken up into multiple discrete time periods at some EAF, AOD, or both and that the opacity plume for charging sometimes lasts after charging has stopped. Therefore, testing opacity ''during charging'' for a continuous 3-minute period, as the final EAF NSPS rule required, would not be possible in the case of multiple discrete charges or if the charging plume continues to be observable after charging of materials ceases.

We also discovered a typographical error in the standards section of subpart AAb for measurement of shop opacity, where charging was mentioned twice instead of once and with two different sets of requirements. The duplicative references to ''charging'' would require testing both for 3 minutes and 6 minutes, and require no testing for tapping. This was inconsistent with other provisions of the rule that accurately described the testing requirements and with the EPA's clearly stated intent in the preamble that the 6-minute opacity testing was intended for tapping and the 3-minute testing was intended for charging. (88 FR 58459).

Additional errors we are addressing in this action include: (1) correcting in 40 CFR 60.273(d)(2), 60.273a(d)(2), and 60.273b(d)(2) the omitted timing of the requirement to conduct shop opacity monitoring when more than one EAF are located in a shop; and (2) correcting in 40 CFR 60.273(c), 60.273a(c), and 60.273b(e) the erroneous requirement included in the final rule that all fabric filters must have a continuous opacity monitoring system (COMS) or bag leak detection system (BLDS) by renumbering the regulatory text as 40 CFR 60.273(c)(1)–(c)(3)/60.273a(c)(1)–(c)(3) and removing the phrase ''on all fabric filters'' in 40 CFR 60.273b(e); and (3) renumbering rule text in 40 CFR 60.274b(c)(1)–(c)(5) to clarify that the requirements in paragraphs (c)(1)–(c)(3) of §§ 60.274, 60.274a, and 60.274b are a choice, and that (c)(4) and (c)(5) apply to any of the choices made in (c)(1)–(c)(3).

We also discovered that several paragraphs under ''Monitoring of operations'' in subpart AA § 60.274(b), (c), and (i), subpart AAa § 60.274a(b), (c), and (h), and subpart AAb § 60.274b(b), (c), and (h) do not reflect what we plainly stated in the preamble (88 FR 58465, 58466, 58484), in response to comments, that we were not adopting the proposed rule provisions that would have required continuously monitoring of volumetric flow rate at each separately ducted hood and furnace static pressure, and instead were finalizing provisions that require recording these parameters as no greater than 15-minute integrated block averages. Relatedly, the 2023 final regulatory text was ambiguous as to whether facilities needed to monitor 15-minute rolling averages or integrated block averages. Our stated intent in the preamble to the final rule was to require 15-minute integrated block averages; therefore, in this action, in §§ 60.274 and 60.274a, we are clarifying that volumetric flow rates and furnace static pressure are to be recorded as no greater than 15-minute integrated block averages.

Finally, we also discovered a phrase under ''Recordkeeping and reporting'' in subparts AA, AAa, and AAb under 40 CFR 60.276(a)/60.276a(c)/60.276b(c) that was unintentionally and inadvertently deleted in the final regulations in regard to operation of fan motors for owners and operators that elect to install a furnace static pressure monitoring device. Specifically, the regulatory text inadvertently omitted a provision stating that ''operation of control system fan motor amperes at values exceeding ±15 percent of the value established under 40 CFR 60.274(c)/60.274a(c)/60.274b(c)'' also constitutes unacceptable operation and maintenance of the affected facility. Therefore, we are restoring this phrase

minutes. Steel is produced in batches, where a single batch can last from 1 hour to 10 hours, where 5 hours is a typical batch time period. Charging, therefore, is a small subset of the time that an EAF is operating.

[2] On the same day, the Steel Associations filed a petition for review of the 2023 final rule in the D.C. Circuit. *Am. Iron & Steel Institute* v. *EPA,* No. 23–1292. The litigation is presently in abeyance while the EPA undertakes this action.

in subparts AA, AAa, and AAb under 40 CFR 60.276(a)/60.276a(c)/60.276b(c).

The EPA is issuing this interim final rule to correct these errors included in the EAF NSPS 2023 final rule.

B. Specific Regulatory Revisions

The regulatory revisions to 40 CFR part 60, subparts AA, AAa, and AAb that are being revised in this action include the following:

1. Corrections to 40 CFR Part 60, Subparts AA and AAa

In this action, we are removing the inadvertently included requirement in 40 CFR 60.273(d)(2) and 60.273a(d)(2) ''Emission monitoring'' for lengthy, conflicting, and costly weekly opacity monitoring from the end of one EAF, AOD, or both heat cycles to the end of the following heat cycle, a time period that lasts from 1 to 10 hours, with an estimated average of 5 hours. As written, the promulgated 2023 final rule erroneously required hours-long testing that would have significant cost impacts, which are estimated to be approximately $6 million per year. This requirement was not proposed and was inadvertently added into the final rule, without appropriate analysis and opportunity for public comment. Moreover, this requirement is not necessary to ensure compliance with the standard and would cause a significant unintended financial impact on the EAF, AOD, or both currently subject to NSPS subpart AA and AAa.

We are also clarifying when to conduct the weekly shop opacity monitoring when there is more than one EAF located in a shop by adding ''during the heat cycle as defined in 40 CFR 60.271,'' which was inadvertently omitted from the final rule. As written in the 2023 final rule 40 CFR 60.273(d)(2) and 60.273a(d)(2), the regulations are unclear as to when opacity monitoring should be completed. The clarification being finalized in this interim final current rule will require that once a week, facility shops with more than one EAF are to perform the required daily opacity monitoring when all EAF in the shop are operating. Following these corrections, subparts AA and AAa retain the requirement for daily opacity testing during melting and refining, tapping, and charging for time periods of 6, 6, and 3 minutes, respectively, as well as the requirement that facilities with more than one EAF in a shop test opacity once a week with all EAF in operation.

In this action, we are also correcting errors in 40 CFR 60.273(c) and 60.273a(c) by removing the erroneous requirement included in the final rule that all fabric filters would need to install COMS or BLDS. As written, the promulgated 2023 final rule required a large capital investment for existing facilities with multi-stack fabric filters to install COMS or BLDS on each fabric filter. This erroneous requirement in the final rule is in direct conflict with both the preamble text (88 FR 58465) and our finalized regulations in 40 CFR 60.273(e) and 60.273a(e), which only require BLDS for single stack fabric filters that do not have COMS. Therefore, by adding in paragraph and subparagraph numbers (1)(i), (1)(ii), (2), and (3) in 40 CFR 60.273(c) and 60.273a(c) to make clear that multi-stack fabric filters are not required to install COMS or BLDS if observations of the opacity of the visible emission from the control device are performed by a certified visible emission observer, we will align § 60.273(c) and § 60.273a(c) with § 60.273(e) and § 60.273a(e), respectively, and eliminate the requirement for existing facilities to install COMS or BLDS by February 21, 2024.

We are clarifying 40 CFR 60.274(c)(1)–(5) and 60.274a(c)(1)–(5), which, as written in the final regulations, could be interpreted to allow the owner or operator to choose from one of five ways to monitor EAF operation when demonstrating compliance with the shop opacity standards in 40 CFR 60.272(a)(3) and 60.272a(a)(3) where a hood is used for capture, as described in paragraphs 40 CFR 60.274 and 60.274a in subparagraphs (c)(1), (c)(2), (c)(3), (c)(4), and (c)(5). This was an error. We are correcting the requirements, as intended, to clearly allow three choices of subparagraphs (c)(1), (c)(2), or (c)(3) to demonstrate compliance, but also to require a demonstration of compliance with both subparagraphs (c)(4) and (c)(5). These three choices of monitoring in subparagraphs (c)(1), (c)(2), and (c)(3) are choices between (c)(1), monitoring fan motor amperes at each damper position; (c)(2), monitoring volumetric flow rate through each hood; or (c)(3), monitoring volumetric flow rate at the control device inlet and with damper position. The last two subparagraphs of 40 CFR 60.274 and 60.274a, specifically, (c)(4) and (c)(5), were intended to apply to any of the three monitoring choices in (c)(1), (c)(2), or (c)(3), where (c)(4) sets the time requirement for the monitoring as a rolling averaging period not to exceed 15 minutes, and (c)(5) describes how facilities can petition the Administrator to change any of the operating conditions that they had previously chosen among (c)(1), (c)(2), or (c)(3). Without this correction, the regulations do not clearly indicate how facilities are to appropriately monitor EAF, AOD, or both when demonstrating compliance with the shop opacity standard in 40 CFR 60.272(a)(3) and 60.272a(a)(3) where a hood is used for capture. Therefore, as written in the 2023 final rule, facilities already subject to the applicable standards could inadvertently become noncompliant.

We also are correcting subparts AA and AAa, ''Monitoring of operations'' in 40 CFR 60.274(b), (c), and (i) and 60.274a(b), (c), and (h) for the parameters of volumetric flow rate through each separately ducted hood and furnace static pressure by removing the requirements to record a rolling 15-minute average on a continuous basis. As stated in the final rule preamble (88 FR 58465, 58466), we intended to change this proposed provision in response to comments and replace it with the requirement to record as no greater than 15-minute integrated block averages. Without these corrections, the regulations would be inconsistent with our intended final action as described in the 2023 final rule preamble, would not clearly indicate how facilities are to appropriately monitor EAF, AOD, or both, and facilities already subject to the applicable standards could inadvertently become noncompliant.

Finally, we are correcting a requirement that was unintentionally and inadvertently deleted in subparts AA and AAa, ''Recordkeeping and reporting'' in 40 CFR 60.276(a)/60.276a(c)/60.276b(c), regarding the operation of fan motors for owners and operators that elect to install a furnace static pressure monitoring device under 40 CFR 60.274(f)/60.274a(f)/60.274b(f). We are restoring the provision specifying that ''operation of control system fan motor amperes at values exceeding ±15 percent of the value established under 40 CFR 60.274(c)/60.274a(c)/60.274b(c)'' also constitutes unacceptable operation and maintenance of the affected facility in addition to operation at flow rates lower than those established under 40 CFR 60.274(c)/60.274a(c)/60.274b(c). We never proposed to modify this provision and its deletion in the final rule was unintended. As written in the final regulations, facilities already subject to the applicable standards could inadvertently become noncompliant if we do not make this correction.

2. Corrections to Subpart AAb

We are making the same correction to subpart AAb as described in in II.B.1 for subparts AA and AAa because the requirement for lengthy, conflicting, and costly weekly opacity monitoring from the end of one EAF, AOD, or both heat cycles to the end of the following heat cycle'' in 40 CFR 60.273b(d)(2) ''Emission monitoring'' was not proposed in 2022 (87 FR 29710), was not intended to be included in the promulgated 2023 final rule (88 FR 58459), and is not necessary to ensure compliance with the standards. In addition, this provision was not included in the cost estimates for the final rule or economic impact analysis. The correction for subpart AAb in this action returns the requirement in 40 CFR 60.273b(d)(2) to what had been proposed (87 FR 29710), where opacity testing was required to be performed at least once per day when the furnace is operating. This correction is consistent with the requirements in the standards section of the rule, at 40 CFR 60.272b(a)(3), which were unchanged between the proposed rule (87 FR 29710) and promulgated final rule (88 FR 58459).

We are also clarifying, as we are in subparts AA and AAa, when to conduct the weekly shop opacity monitoring when there is more than one EAF located in a shop, by adding ''during the heat cycle as defined in 40 CFR 60.271b.'' This clarification requires that once a week, facility shops with more than one EAF perform the required daily opacity monitoring when all EAFs are operating.

Additionally in this action, we are correcting procedures for opacity testing of shop emissions under Method 9 in subpart AAb at 40 CFR 60.271b ''Definitions,'' 40 CFR 60.272b(a)(3) ''Standard for particulate matter,'' and 40 CFR 60.273b(d)(3) ''Emission monitoring,'' to address the situation where charging periods at some EAF, AOD, or both may be broken into multiple, shorter periods of charging rather than one continuous charge, and for delayed plumes from charging. The final rule promulgated in 2023 (88 FR 58442) defined the charging testing period in subpart AAb as ''12 15-second *continuous* opacity observations'' (a total of 3 minutes) to accommodate the shorter periods of charging that are less than the 6 minutes required for melting and refining, and for tapping. However, as promulgated in the 2023 final rule, this requirement may not always be technically feasible for a facility to meet. In this interim final rule, we are clarifying that the 3 minutes of opacity observation does not need to be continuous (although the observation periods should still total 3 minutes), to accommodate EAF, AOD, or both that are charged in multiple short batches of less than a duration of 3 minutes each.

In some instances, the opacity due to charging can continue to be observable after the charging activity has stopped, but before melting and refining begins. As provided in the 2023 final rule, the compliance testing requirements cannot be accurately completed at some facilities due to short charging periods and the requirement to only test opacity during charging. In this action, we are thus clarifying that the charging opacity observations can continue after the activity of charging ceases, up until melting and refining begins, which is necessary when opacity observations during charging have not yet reached 3 minutes in total and the charging opacity continues up until melting and refining begins.

Therefore, this action corrects the charging opacity measurement regulatory text to remove ''continuous,'' and define the opacity measurement period as beginning when charging is first initiated and continuing until melting and refining begins, for a minimum of three minutes of total opacity readings. The result of this change is that the opacity test result for charging should be calculated from the average of the highest twelve 15-second opacity observations (total of 3 minutes) during the charging period that is defined as beginning when charging is first initiated and continuing until melting and refining begins, to produce a 3-minute opacity average in an integrated sample, as permitted under section 2.5 of Method 9.

We are correcting in this interim final rule a typographic error in 40 CFR 60.272b(a)(3) ''Standard for particulate matter'' promulgated in the final rule in 2023 (88 FR 58459), where charging was required to be tested both *without modification* of the 6-minute observation time period as well as *with modification* to reduce the observation time period to 3 minutes. The former time period of 6 minutes should have been attributed to tapping and not charging, as is done in two other places in the 2023 final rule (*i.e.,* in 40 CFR 60.271b ''Definitions'' and 40 CFR 60.273b(d)(3) ''Emission monitoring''). Therefore, we are correcting the first mention in 40 CFR 60.272b(a)(3) from ''charging'' to ''tapping''.

Additionally in this action, we are making the same correction to subpart AAb, as described in in II.B.1, for subparts AA and AAa, by removing the requirement erroneously included in the final regulations in 40 CFR 60.273b(e) that all fabric filters need to have COMS or BLDS installed. By removing the phrase ''on all fabric filters'' to make clear that multi-stack fabric filters are not required to install COMS or BLDS if observations of the opacity of the visible emission from the control device are performed by a certified visible emission observer, we will align 40 CFR 60.273b(e) with 40 CFR 60.273b(c) and eliminate the need for all new, modified or reconstructed facilities to install COMS or BLDS upon startup. We are also making the same correction to subpart AAb, as described in II.B.1 for subparts AA and AAa, to allow a choice between 40 CFR 60.274b(c)(1), (c)(2), or (c)(3) to demonstrate compliance, but then also require a demonstration of compliance with both subparagraphs (c)(4) and (c)(5). Without this edit, the regulations do not clearly indicate how facilities are to appropriately monitor EAF, AOD or both when demonstrating compliance with the shop opacity standard in 40 CFR 60.272b(a)(3) where a hood is used for capture. Therefore, as written in our final rule, facilities could inadvertently become noncompliant.

We are making the same correction to subpart AAb under ''Monitoring of operations'' in 40 CFR 60.274b(b), (c), and (h), as described in II.B.1 for subparts AA and AAa, for the parameters of volumetric flow rate through each separately ducted hood and furnace static pressure. We are removing the requirements to record ''rolling 15-minute averages on a continuous basis'' for the values for these parameters and replacing with the requirement to ''record as no greater than 15-minute integrated block averages.''

Finally, we are making the same corrections to subpart AAb under ''Recordkeeping and reporting requirements,'' as described in II.B.1 for subparts AA and AAa, for a requirement that was unintentionally and inadvertently deleted in the final rule for subpart AAb under 40 CFR 60.276b(c), in regard to operation of fan motor for owners and operators that elect to install a furnace static pressure monitoring device under 40 CFR 60.274b(f). We are restoring the provision specifying that ''operation of control system fan motor amperes at values exceeding ±15 percent of the value established under 40 CFR 60.274b(c)'' also constitutes unacceptable operation and maintenance of the affected facility in addition to operation at flow rates lower than those established under 40 CFR 60.274b(c).

III. Rulemaking Procedures

As noted in section I.C. of this document, the EPA's authority for the rulemaking procedures followed in this action is provided by APA section 553.[3] In general, an agency issuing a rule under the procedures in APA section 553 must provide prior notice and an opportunity for public comment, but APA section 553(b)(B) includes an exemption from notice-and-comment requirements ''when the agency for good cause finds (and incorporates the finding and a brief statement of reasons, therefore, in the rule issued) that notice and public procedure thereon are impracticable, unnecessary, or contrary to the public interest.'' This action is being issued without prior notice or opportunity for public comment because the EPA finds that the APA ''good cause'' exemption from notice-and-comment requirements applies here.

Following notice-and-comment procedures is impracticable and unnecessary for this action. The costly, conflicting, and burdensome opacity emissions monitoring requirements inadvertently included in subparts AA, AAa, and AAb were not proposed and were never intended to become part of the regulatory text of the 2023 final rule. These opacity monitoring requirements, as described in section II. of this action, would add significant cost impacts to new and currently operating sources that were not considered or included in the 2023 final rule because the EPA neither intended nor anticipated finalizing such a provision. These erroneous requirements are already in effect with respect to facilities subject to subpart AAb and will apply to facilities subject to NSPS subparts AA and AAa on February 21, 2024. Thus, it is critical to timely avoid this unintended and significant burden.

Regarding the correction to subpart AAb for procedures for opacity testing of shop emissions under Method 9, the regulations as finalized are technically impossible for some facilities to meet due to opacity plumes that could be delayed after charging stops, but before melting and refining begins. Accordingly, a new facility that is constructed, modified, or reconstructed would be subject to compliance assurance provisions in subpart AAb with which the facility may not be able to comply. This would create an unreasonable situation where a facility could be considered to be in violation because it cannot comply with these compliance assurance requirements, even though it would be able to technically meet the applicable performance standard. Therefore, it is imperative that the EPA make this correction to ensure new, modified, and reconstructed are subject to opacity testing requirements that are achievable.

Finally, this action is correcting several inadvertent errors in the regulatory text of the final rule. First, this action is removing a duplicative and contradictory reference in 40 CFR 60.272b(a)(3) to the charging requirement, which does not change the substance of the testing requirements. Second, this action is correcting regulatory text in subparts AA, AAa, and AAb that accidentally retained certain proposed language, contrary to the EPA's expressly stated intent in the final rule preamble. And third, the EPA is restoring provisions that were unintentionally deleted without prior notice or explanation and which should have been retained. This action corrects these oversights which, as described in section II., could cause some facilities to become inadvertently noncompliant with the standards and subject to potential enforcement action if not expeditiously corrected.

This action is effective immediately upon publication. Section 553(d) of the APA requires publication of the final rule to precede the effective date by at least 30 days unless, as relevant here, the rule relieves a restriction (40 CFR 553(d)(1)) or the agency finds good cause to make the rule effective sooner (40 CFR 553(d)(3)). Under APA section 553(d)(1), an exception applies to a rule that ''grants or recognizes an exemption or relieves a restriction.'' Because the corrections in this action relieve restrictions placed on facilities from the 2023 final rule (*e.g.,* removing an unintended, burdensome and costly opacity monitoring requirement and relaxing unachievable testing requirements), the normal 30-day minimum period between this action's dates of publication and effectiveness is not required. Additionally, as explained throughout this action, because the corrections to the final rule relieve impracticable regulatory burdens and make ministerial clarifications, there is a secondary good cause basis for immediate effectiveness under APA section 553(d)(3). See *Omnipoint Corp.* v. *Fed. Commc'n Comm'n,* 78 F.3d 620, 630 (D.C. Cir. 1996) (in determining whether good cause exists to make a rule immediately effective, an agency should ''balance the necessity for immediate implementation against principles of fundamental fairness which require that all affected persons be afforded a reasonable amount of time to prepare for the effective date of its ruling''). Because the rule does not impose any new regulatory requirements, the regulated community does not need time to prepare for the rule to come into effect.

IV. Request for Comment

As explained in section III. of this document, the EPA finds good cause to take this interim final action without prior notice or opportunity for public comment. However, the EPA is providing an opportunity for comment on the content of the amendments and, thus, requests comment on the corrections described in this rule. The EPA is not reopening for comment any provisions of the 2023 final rule other than the specific provisions that are expressly amended in this interim final rule.

V. Statutory and Executive Order Reviews

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

A. Executive Order 12866: Regulatory Planning and Review, as Amended by 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. The Office of Management and Budget (OMB) has previously approved the information collection activities that apply to the EAF facilities affected by this action and has assigned OMB control number 2060–0038. This action does not change the information collection requirements.

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.

D. Unfunded Mandates Reform Act of 1995 (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

[3] Under CAA section 307(d)(1)(C), the EPA's promulgation or revision of any standard of performance under CAA section 111 would normally be subject to the rulemaking procedural requirements of CAA section 307(d), including notice-and-comment procedures, but CAA section 307(d) does not apply ''in the case of any rule or circumstance referred to in subparagraphs (A) or (B) of [APA section 553(b)].'' CAA section 307(d)(1).

uniquely affect small governments. The action imposes no enforceable duty on any state, local or tribal governments or the private sector. This rule corrects unintended errors in previous rule.

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. This rule will implement corrections and clarifications to rule text applicable directly to the regulated industry that needed clarification or that were erroneously included in final rule. 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. The EPA does not believe there are disproportionate risks to children because of this action since it will not result in any changes to the control of air pollutants.

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 action does not involve technical standards; therefore, the NTTAA does not apply.

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.

K. Congressional Review Act (CRA)

This action is subject to the Congressional Review Act (CRA), 5 U.S.C. 801–808, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. The CRA allows the issuing agency to make a rule effective sooner than otherwise provided by the CRA if the agency makes a good cause finding that notice and comment rulemaking procedures are impracticable, unnecessary, or contrary to the public interest (5 U.S.C. 808(2)). The EPA has made a good cause finding for this rule as discussed in section III. of this document, including the basis for that finding.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedures, Air pollution control, Incorporation by reference, Reporting and recordkeeping requirements.

Michael S. Regan,

Administrator.

For the reasons set forth in the preamble, the EPA amends 40 CFR part 60 as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

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

Subpart AA—Standards of Performance for Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974, and On or Before August 17, 1983

■ 2. Amend § 60.273 by revising paragraphs (c) and (d)(2) to read as follows:

§ 60.273 Emission monitoring.

* * * * *

(c)(1) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the control device(s) is not required:

(i) On any modular, multistack, negative-pressure or positive-pressure fabric filter if observations of the opacity of the visible emission from the control device are performed by a certified visible emission observer; or

(ii) On any single-stack fabric filter if observations of the opacity of the visible emissions from the control device are performed by a certified visible emission observer and the owner installs and operates a bag leak detection system according to paragraph (e) of this section whenever the control device is being used to remove particulate matter from the EAF.

(2) Visible emission observations shall be conducted at least once per day of the control device for at least three 6-minute periods when the furnace is operating in the melting and refining period. All visible emissions observations shall be conducted in accordance with EPA Method 9 of appendix A to this part, or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271.

(3) If visible emissions occur from more than one point, the opacity shall be recorded for any points where visible emissions are observed. Where it is possible to determine that a number of visible emission points relate to only one incident of the visible emission, only one set of three 6-minute observations will be required. In that case, EPA Method 9 observations must be made for the point of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident. Records shall be maintained of any 6-minute average that is in excess of the emission limit specified in § 60.272(a)(2).

(d) * * *

(2) No less than once per week, during a heat time as defined in § 60.271, a melt shop with more than one EAF shall conduct these readings while all EAFs are in operation. All EAFs are not required to be on the same schedule for tapping.

* * * * *

■ 3. Amend § 60.274 by revising paragraphs (b)(1), (b)(3), (c), and (i)(9) to read as follows:

§ 60.274 Monitoring of operations.

* * * * *

(b) * * *

(1) Monitor and record once per shift the block 15-minute average furnace static pressure (if a DEC system is in

use, and a furnace static pressure gauge is installed according to paragraph (f) of this section) and either:

(i) Install, calibrate, and maintain a monitoring device that continuously records the capture system fan motor amperes and damper position(s); or

(ii) Monitor and record as no greater than 15-minute integrated block average basis the volumetric flow rate through each separately ducted hood; or

(iii) Install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate at the control device inlet and record damper position(s).

* * * * *

(3) Parameters monitored pursuant to this paragraph, excluding damper position, shall be recorded as integrated block averages not to exceed 15 minutes.

(c)(1) When the owner or operator of an affected facility is required to demonstrate compliance with the standards under § 60.272(a)(3) and at any other time that the Administrator may require (under section 114 of the CAA, as amended), the owner or operator shall, during periods in which a hood is operated for the purpose of capturing emissions from the affected facility subject to paragraph (b) of this section, either:

(i) Monitor and record the fan motor amperes at each damper position, and damper position consistent with paragraph (i)(5) of this section; or

(ii) Monitor and record as no greater than 15-minute integrated block average basis the volumetric flow rate through each separately ducted hood; or

(iii) Install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate at the control device inlet and monitor and record the damper position consistent with paragraph (i)(5) of this section.

(2) Parameters monitored pursuant to this paragraph, excluding damper position, shall be recorded as integrated block averages not to exceed 15 minutes.

(3) The owner or operator may petition the Administrator or delegated authority for reestablishment of these parameters whenever the owner or operator can demonstrate to the Administrator's or delegated authority's satisfaction that the EAF operating conditions upon which the parameters were previously established are no longer applicable. The values of the parameters as determined during the most recent demonstration of compliance shall be the appropriate operational range or control set point throughout each applicable period. Operation at values beyond the accepted operational range or control set point may be subject to the requirements of § 60.276(a).

* * * * *

(i) * * *

(9) Parameters monitored pursuant to paragraphs (i)(6) through (8) of this section shall be recorded as integrated block averages not to exceed 15 minutes.

■ 4. Amend § 60.276 by revising paragraph (a) to read as follows:

§ 60.276 Recordkeeping and reporting requirements.

(a) Continuous operation at a furnace static pressure that exceeds the operational range or control setting under § 60.274(g), for owners and operators that elect to install a furnace static pressure monitoring device under § 60.274(f) and either operation of control system motor amperes at values exceeding ±15 percent of the value established under § 60.274(c) or operation at flow rates lower than those established under § 60.274(c) may be considered by the Administrator or delegated authority to be unacceptable operation and maintenance of the affected facility. Operation at such values shall be reported to the Administrator or delegated authority semiannually.

* * * * *

■ 5. Amend the subpart AAa heading by revising it to read as follows:

Subpart AAa—Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarbonization Vessels Constructed After August 17, 1983, and On or Before May 16, 2022

* * * * *

■ 6. Amend § 60.273a by revising paragraphs (c) and (d)(2) to read as follows:

§ 60.273a Emission monitoring.

* * * * *

(c)(1) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the control device(s) is not required:

(i) On any modular, multistack, negative-pressure or positive-pressure fabric filter if observations of the opacity of the visible emission from the control device are performed by a certified visible emission observer; or

(ii) On any single-stack fabric filter if observations of the opacity of the visible emissions from the control device are performed by a certified visible emission observer and the owner installs and operates a bag leak detection system according to paragraph (e) of this section whenever the control device is being used to remove particulate matter from the EAF or AOD.

(2) Visible emission observations shall be conducted at least once per day of the control device for at least three 6-minute periods when the furnace is operating in the melting and refining period. All visible emissions observations shall be conducted in accordance with EPA Method 9 of appendix A to this part, or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271.

(3) If visible emissions occur from more than one point, the opacity shall be recorded for any points where visible emissions are observed. Where it is possible to determine that a number of visible emission points relate to only one incident of the visible emission, only one set of three 6-minute observations will be required. In that case, EPA Method 9 observations must be made for the point of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident. Records shall be maintained of any 6-minute average that is in excess of the emission limit specified in § 60.272(a)(2).

(d) * * *

(2) No less than once per week, during the heat cycle as defined in § 60.271a, melt shop with more than one EAF shall conduct these readings while all EAFs are in operation. All EAFs are not required to be on the same schedule for tapping.

* * * * *

■ 7. Amend § 60.274a by revising paragraphs (b)(1), (b)(3), (c), and (h)(9) to read as follows:

§ 60.274a Monitoring of operations.

* * * * *

(b) * * *

(1) Monitor and record once per shift the block 15-minute average furnace static pressure (if a DEC system is in use, and a furnace static pressure gauge is installed according to paragraph (f) of this section) and either:

(i) Install, calibrate, and maintain a monitoring device that continuously records the capture system fan motor amperes and damper position(s);

(ii) Monitor and record as no greater than 15-minute integrated block average basis the volumetric flow rate through each separately ducted hood; or

(iii) Install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate at the control device inlet and record damper positions(s).

* * * * *

(3) Parameters monitored pursuant to this paragraph, excluding damper position, shall be recorded as integrated block averages not to exceed 15 minutes.

(c)(1) When the owner or operator of an affected facility is required to demonstrate compliance with the standards under § 60.272a(a)(3) and at any other time that the Administrator may require (under section 114 of the CAA, as amended), the owner or operator shall, during periods in which a hood is operated for the purpose of capturing emissions from the affected facility subject to paragraph (b) of this section, either:

(i) Install, calibrate, and maintain a monitoring device that continuously records the fan motor amperes at each damper position, and damper position consistent with paragraph (h)(5) of this section; or

(ii) Monitor and record as no greater than 15-minute integrated block average basis the volumetric flow rate through each separately ducted hood; or

(iii) Install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate at the control device inlet and monitor and record the damper position consistent with paragraph (h)(5) of this section.

(2) Parameters monitored pursuant to this paragraph, excluding damper position, shall be recorded as integrated block averages not to exceed 15 minutes.

(3) The owner or operator may petition the Administrator or delegated authority for reestablishment of these parameters whenever the owner or operator can demonstrate to the Administrator's or delegated authority's satisfaction that the affected facility operating conditions upon which the parameters were previously established are no longer applicable. The values of the parameters as determined during the most recent demonstration of compliance shall be the appropriate operational range or control set point throughout each applicable period. Operation at values beyond the accepted operational range or control set point may be subject to the requirements of § 60.276a(c).

* * * * *

(h) * * *

(9) Parameters monitored pursuant to paragraphs (h)(6) through (8) of this section shall be recorded as integrated block averages not to exceed 15 minutes.

■ 8. Amend § 60.276a by revising paragraph (c) to read as follows:

§ 60.276a Recordkeeping and reporting requirements.

* * * * *

(c) Continuous operation at a furnace static pressure that exceeds the operational range or control setting under § 60.274a(g), for owners and operators that elect to install a furnace static pressure monitoring device under § 60.274a(f) and either operation of control system fan motor amperes at values exceeding ±15 percent of the value established under § 60.274a(c) or operation at flow rates lower than those established under § 60.274a(c) may be considered by the Administrator or delegated authority to be unacceptable operation and maintenance of the affected facility. Operation at such values shall be reported to the Administrator or delegated authority semiannually.

* * * * *

Subpart AAb—Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarbonization Vessels Constructed After May 16, 2022

■ 9. Amend § 60.271b by revising the definition ''Shop opacity'' to read as follows:

§ 60.271b Definitions.

* * * * *

Shop opacity means the arithmetic average of 24 observations of the opacity of any EAF or AOD emissions emanating from, and not within, the shop, during melting and refining, and during tapping, taken in accordance with Method 9 of appendix A of this part; and during charging, according to the procedures in section 2.5 of Method 9 in appendix A to part 60 of this chapter, with the following modifications: begin reading opacity when charging is first initiated and continue reading until melting and refining begins, or for a minimum of 3 minutes total. From the readings collected, take the average of the highest 12 15-second opacity observations (total of 3 minutes) during this period to determine the 3-minute opacity average associated with charging. For the daily opacity observation during melting and refining, facilities may measure opacity by EPA Method 22 of appendix A of this part, modified to require the recording of the aggregate duration of visible emissions at 15-second intervals. Alternatively, ASTM D7520–16 (incorporated by reference, see § 60.17), may be used with the following five conditions:

(1) During the digital camera opacity technique (DCOT) certification procedure outlined in section 9.2 of ASTM D7520–16 (incorporated by reference, see § 60.17), the owner or operator 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) 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 § 60.17);

(3) The owner or operator must follow the recordkeeping procedures outlined in § 60.7(f) for the DCOT certification, compliance report, data sheets, and all raw unaltered JPEGs used for opacity and certification determination;

(4) 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;

(5) 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 § 60.17) and these requirements is on the facility, DCOT operator, and DCOT vendor.

* * * * *

■ 10. Amend § 60.272b by revising paragraph (a)(3) to read as follows:

§ 60.272b Standard for particulate matter.

(a) * * *

(3) Exit from a shop and, due solely to the operations of any affected EAF(s) or AOD vessel(s) during melting and refining exhibit greater than 0 percent opacity, and during tapping exhibit greater than 6 percent opacity, as measured in accordance with Method 9 of appendix A of this part; and during charging, exhibit greater than 6 percent opacity, as measured according to the procedures in section 2.5 of Method 9 in appendix A to part 60 of this chapter, with the modification of this section of Method 9, as follows: begin reading opacity when charging is first initiated and continue reading until melting and refining begins, or for a minimum of 3 minutes total. From the readings

collected, take the average of the highest 12 15-second opacity observations (total of 3 minutes) during this period to determine the 3-minute opacity average associated with charging. For the daily opacity observation during melting and refining, facilities may measure opacity by EPA Method 22 of appendix A of this part, modified to require the recording of the aggregate duration of visible emissions at 15-second intervals. As an alternative, facilities may measure opacity according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271 or, for the daily opacity observations during melting and refining, exhibit 0 seconds of visible emissions as measured by EPA Method 22 of appendix A of this part, modified to require the recording of the aggregate duration of visible emissions at 15-second intervals. Shop opacity shall be recorded for any point(s) during melting and refining, during charging, and during tapping where visible emissions are observed. Where it is possible to determine that a number of visible emission sites relate to only one incident of visible emissions during melting and refining, during charging, or during tapping, only one observation of shop opacity or visible emissions will be required during melting and refining, during charging, or during tapping. In this case, the shop opacity or visible emissions observations must be made for the point of highest emissions during melting and refining, during charging, or during tapping that directly relates to the cause (or location) of visible emissions observed during a single incident.

* * * * *

■ 11. Amend § 60.273b by revising paragraphs (c), (d)(2), (d)(3), and (e) introductory text to read as follows:

§ 60.273b Emission monitoring.

* * * * *

(c)(1) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the control device(s) is not required:

(i) On any modular, multistack, negative-pressure or positive-pressure fabric filter if observations of the opacity of the visible emission from the control device are performed by a certified visible emission observer; or

(ii) On any single-stack fabric filter if observations of the opacity of the visible emissions from the control device are performed by a certified visible emission observer and the owner installs and operates a bag leak detection system according to paragraph (e) of this section whenever the control device is being used to remove particulate matter from the EAF or AOD.

(2) Visible emission observations shall be conducted at least once per day of the control device for at least three 6-minute periods when the furnace is operating in the melting and refining period. All visible emissions observations shall be conducted in accordance with EPA Method 9 of appendix A to this part, or, as an alternative, according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271.

(3) If visible emissions occur from more than one point, the opacity shall be recorded for any points where visible emissions are observed. Where it is possible to determine that a number of visible emission points relate to only one incident of the visible emission, only one set of three 6-minute observations will be required. In that case, EPA Method 9 observations must be made for the point of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident. Records shall be maintained of any 6-minute average that is in excess of the emission limit specified in § 60.272b(a)(2).

(d) * * *

(2) No less than once per week, during the heat cycle as defined in § 60.271b, a melt shop with more than one EAF shall conduct these readings while all EAFs are in operation. All EAFs are not required to be on the same schedule for tapping.

(3) Shop opacity shall be determined as the arithmetic average of 24 consecutive 15-second opacity observations of emissions from the shop taken in accordance with Method 9 during melting and refining and during tapping; and during charging determined according to the procedures in section 2.5 of Method 9 in appendix A to part 60 of this chapter, with the modification as follows: begin reading opacity when charging is first initiated and continue reading until melting and refining begins, or for a minimum of 3 minutes total. From the readings collected, take the average of the highest 12 15-second opacity observations (total of 3 minutes) during this period to determine the 3-minute opacity average associated with charging. For the daily opacity observation during melting and refining, facilities may measure opacity by EPA Method 22 of appendix A of this part, modified to require the recording of the aggregate duration of visible emissions at 15-second intervals. As an alternative, facilities may measure the opacity according to ASTM D7520–16 (incorporated by reference, see § 60.17), with the caveats described under *Shop opacity* in § 60.271, or, during melting and refining, as the total duration of visible emissions measured according to EPA Method 22 over a 6-minute period, modified to require the recording of the aggregate duration of visible emissions at 15-second intervals. Shop opacity shall be recorded for any point(s) where visible emissions are observed. Where it is possible to determine that a number of visible emission points relate to only one incident of visible emissions, only one observation of shop opacity will be required. In this case, the shop opacity observations must be made for the point of highest opacity that directly relates to the cause (or location) of visible emissions observed during a single incident. Shop opacity shall be determined daily during melting and refining, during charging, and during tapping.

(e) A bag leak detection system must be installed and operated on all single-stack fabric filters whenever the control device is being used to remove particulate matter from the EAF or AOD vessel if the owner or operator elects not to install and operate a continuous opacity monitoring system as provided for under paragraph (c) of this section. In addition, the owner or operator shall meet the visible emissions observation requirements in paragraph (c) of this section. The bag leak detection system must meet the specifications and requirements of paragraphs (e)(1) through (8) of this section.

* * * * *

■ 12. Amend § 60.274b by revising paragraphs (b), (c), and (h)(9) to read as follows:

§ 60.274b Monitoring of operations.

* * * * *

(b) Except as provided under paragraph (e) of this section, the owner or operator subject to the provisions of this subpart shall conduct the following monitoring of the capture system to demonstrate continuous compliance:

(1) If a DEC system is in use, according to paragraph (f) of this section, monitor and record once per shift the block 15-minute average furnace static pressure and any one of (2) through (4) in this paragraph:

(2) Install, calibrate, and maintain a monitoring device that continuously records the fan motor amperes at each damper position, and damper position consistent with paragraph (h)(5) of this section; or

(3) Monitor and record as no greater than 15-minute integrated block average basis the volumetric air flow rate at each separately ducted hood; or

(4) Install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate at the control device inlet and monitor and record the damper position consistent with paragraph (h)(5) of this section.

(5) The furnace static pressure monitoring device(s) shall be installed in an EAF or DEC duct prior to combining with other ducts and prior to the introduction of ambient air, at a location that has no flow disturbance due to the junctions.

(6) The volumetric flow monitoring device(s) may be installed in any appropriate location in the capture system such that reproducible flow rate monitoring will result. The flow rate monitoring device(s) shall have an accuracy of ±10 percent over its normal operating range and shall be calibrated according to the manufacturer's instructions. The Administrator may require the owner or operator to demonstrate the accuracy of the monitoring device(s) relative to EPA Methods 1 and 2 of appendix A of this part.

(7) Parameters monitored pursuant to this paragraph, excluding damper position, shall be recorded as integrated block averages not to exceed 15 minutes.

(c)(1) When the owner or operator of an affected facility is required to demonstrate compliance with the standards under § 60.272b(a)(3) and at any other time that the Administrator may require (under section 114 of the CAA, as amended), the owner or operator shall, during all periods in which a hood is operated for the purpose of capturing emissions from the affected facility subject to paragraph (b) of this section, either:

(i) Install, calibrate, and maintain a monitoring device that continuously records the fan motor amperes at each damper position, and damper position consistent with paragraph (h)(5) of this section;

(ii) Monitor and record as no greater than 15-minute integrated block average basis the volumetric flow rate through each separately ducted hood; or

(iii) Install, calibrate, and maintain a monitoring device that continuously records the volumetric flow rate at the control device inlet, and monitor and record the damper position consistent with paragraph (h)(5) of this section.

(2) Parameters monitored pursuant to this paragraph, excluding damper position, shall be recorded as integrated block averages not to exceed 15 minutes.

(3) The owner or operator may petition the Administrator or delegated authority for reestablishment of these parameters whenever the owner or operator can demonstrate to the Administrator's or delegated authority's satisfaction that the affected facility operating conditions upon which the parameters were previously established are no longer applicable. The values of the parameters as determined during the most recent demonstration of compliance shall be the appropriate operational range or control set point throughout each applicable period. Operation at values beyond the accepted operational range or control set point may be subject to the requirements of § 60.276b(c).

* * * * *

(h) * * *

(9) Parameters monitored pursuant to paragraphs (h)(6) through (8) of this section shall be recorded as integrated block averages not to exceed 15 minutes.

■ 13. Amend § 60.276b by revising paragraph (c) to read as follows:

§ 60.276b Recordkeeping and reporting requirements.

* * * * *

(c) Operation at a furnace static pressure that exceeds the operational range or control setting under § 60.274b(g), for owners and operators that elect to install a furnace static pressure monitoring device under § 60.274b(f) and either operation of control system fan motor amperes at values exceeding ±15 percent of the value established under § 60.274b(c) or operation ranges or control settings outside of those established under § 60.274b(c) may be considered by the Administrator or delegated authority to be unacceptable operation and maintenance of the affected facility. Operation at such values shall be reported to the Administrator or delegated authority semiannually.

* * * * *

[FR Doc. 2024–02634 Filed 2–13–24; 8:45 am]

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DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 223

[Docket No. 240208–0042; RTID 0648–XR071]

Endangered and Threatened Wildlife and Plants: Listing the Queen Conch as Threatened Under the Endangered Species Act (ESA)

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Final rule.

SUMMARY: We, NMFS, are listing the queen conch (*Aliger gigas,* formerly known as *Strombus gigas*) as a threatened species under the Endangered Species Act (ESA). We have completed a review of the status of queen conch, including efforts being made to protect the species, and considered public comments submitted on the proposed listing rule as well as new information received since the publication of the proposed rule. Based on all of this information, we have determined that the queen conch is not currently in danger of extinction throughout all or a significant portion of its range, but is likely to become so within the foreseeable future. Thus, we are listing the queen conch as a threatened species under the ESA. At this time, we conclude that critical habitat is not yet determinable because data sufficient to perform the required analysis are lacking; any critical habitat designation would be proposed in a separate, future rulemaking.

DATES: This final rule is effective on March 15, 2024.

ADDRESSES: Public comments that were submitted on the proposed rule to list queen conch are available at *https://www.regulations.gov* identified by docket number NOAA–NMFS–2019–0141. A list of references cited in this final rule and other supporting materials are available at: *https://www.fisheries.noaa.gov/species/queen-conch,* or by submitting a request to the National Marine Fisheries Service, Southeast Regional Office, Protected Resources Division, 263 13th Avenue South, St. Petersburg, Florida 33701. Information relevant to inform separate rulemakings to designate critical habitat for queen conch or issue protective regulations for queen conch may be submitted to this mailing address or to the email address indicated below (see **FOR FURTHER INFORMATION CONTACT**).

FOR FURTHER INFORMATION CONTACT: Orian Tzadik, NMFS Southeast Regional Office, (813) 906–0353–C; or *Orian.Tzadik@noaa.gov.*

SUPPLEMENTARY INFORMATION:

Background

On February 27, 2012, we received a petition from WildEarth Guardians to list the queen conch as threatened or endangered throughout all or a significant portion of its range under the ESA. We determined that the petitioned action may be warranted and published a positive 90-day finding in the **Federal** containing hazardous materials must bear the endorsement ''Address Service Requested,'' ''Forwarding Service Requested,'' or ''Return Service Requested.''

2. Pieces containing Ballot Mail under 703.8.0.

* * * * *

Exhibit 1.5.3 Treatment of Undeliverable USPS Marketing Mail and Parcel Select Lightweight

Mailer endorsement	USPS treatment of UAA pieces
* * *	* *
''Change Service Requested'' [1] [4].	Option 1.

Restrictions:

The following restrictions apply:

* * * * *

[Revise the ''Change Service Requested'' Option 1 ''Restrictions'' section by adding a new number 3 to read as follows:]

3. This endorsement is not valid for Ballot Mail under 703.8.0.

* * * * *

Option 2

* * * * *

Restrictions:

The following restrictions apply:

* * * * *

[Revise the ''Change Service Requested'' Option 2 ''Restrictions'' section by adding a new number 3 to read as follows:]

3. This endorsement is not valid for Ballot Mail under 703.8.0.

* * * * *

Colleen Hibbert-Kapler,

Attorney, Ethics and Legal Compliance.

[FR Doc. 2023–25569 Filed 11–17–23; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2022–0481; FRL–9630–02–OAR]

RIN 2060–AV78

New Source Performance Standards Review for Secondary Lead Smelters

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing amendments to the new source performance standards (NSPS) for secondary lead smelters pursuant to the periodic review required by the Clean Air Act (CAA). Specifically, the EPA is finalizing revisions to the NSPS that applies to affected secondary lead smelters constructed, reconstructed, or modified after December 1, 2022 (NSPS subpart La). The EPA is also finalizing amendments to the NSPS for secondary lead smelters constructed, reconstructed, or modified after June 11, 1973, and on or before December 1, 2022, (NSPS subpart L). In addition, we are finalizing the use of EPA Method 22 (Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares) as an alternative for demonstrating compliance with the opacity limit.

DATES: This final rule is effective on November 20, 2023. The incorporation by reference (IBR) of certain publications listed in the rule is approved by the Director of the Federal Register as of November 20, 2023.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2022–0481. 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 will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Amber Wright, 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) 541–4680; email address: *wright.amber@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:

ABR Association of Battery Recyclers
ASTM ASTM, International
BSER best system of emission reduction
CAA Clean Air Act
CBI Confidential Business Information
CFR Code of Federal Regulations
DCOT digital camera opacity technique
EJ environmental justice
EPA Environmental Protection Agency
ERT Electronic Reporting Tool
FR Federal Register
HEPA high efficiency particulate air
IBR incorporation by reference
ICR information collection request
km kilometers
mg/dscm milligram per dry standard cubic meter
NAICS North American Industry Classification System
NESHAP national emission standards for hazardous air pollutants
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement
OAQPS Office of Air Quality Planning and Standards
OMB Office of Management and Budget
PDF portable document format
PM particulate matter
PRA Paperwork Reduction Act
RFA Regulatory Flexibility Act
RIN Regulatory Information Number
SOP standard operating procedures
SSM startup, shutdown, and malfunctions
UMRA Unfunded Mandates Reform Act
U.S.C. United States Code
VCS voluntary consensus standard
WESP wet electrostatic precipitator

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

I. General Information

A. Does this action apply to me?

The source category that is the subject of this final action is composed of secondary lead smelters regulated under CAA section 111, New Source Performance Standards (NSPS). The 2022 North American Industry Classification System (NAICS) code for the source category is 331492. The NAICS code serves as a guide for readers outlining the type of entities that this final action is likely to affect. The NSPS codified in 40 CFR part 60, subpart L are directly applicable to secondary lead smelters constructed, reconstructed, or modified after June 11, 1973, and on or before December 1, 2022. The NSPS codified in 40 CFR part 60, subpart La, are directly applicable to affected facilities that begin construction, reconstruction, or modification after December 1, 2022. Federal, state, local and tribal government entities would not be affected by this action. If you have any questions regarding the applicability of this action to a particular entity, you should carefully examine the applicability criteria found in 40 CFR part 60, subparts L and La, and consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section of this preamble, your state air pollution control agency with delegated authority for NSPS, or your EPA Regional Office.

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 final action is available on the internet at *https://www.epa.gov/stationary-sources-air-pollution/secondary-lead-smelters-new-source-performance-standards-nsps.* 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.

A redline/strikeout version of the rules showing the final edits being made to incorporate the changes to 40 CFR part 60, subpart L and the new text for 40 CFR part 60, subpart La finalized in this action is available in the docket (Docket ID No. EPA–HQ–OAR–2022–0481). Following signature by the EPA Administrator, the EPA also will post a copy of these documents to *https://www.epa.gov/stationary-sources-air-pollution/secondary-lead-smelters-new-source-performance-standards-nsps.*

C. Judicial Review and Administrative Review

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 by January 19, 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 ''[o]nly 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 convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA 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 to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. Environmental Protection Agency, Room 3000, WJC West 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. Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

II. Background

A. What is the statutory authority for this final action?

The EPA's authority for this final rule is CAA section 111, which governs the establishment of standards of performance for stationary sources. Section 111(b)(1)(A) of the CAA requires the EPA Administrator to list categories of stationary sources that in the Administrator's judgment cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for new (and modified or reconstructed) sources in each source category pursuant to CAA section 111(b)(1)(B). These standards are referred to as new source performance standards, or NSPS. The EPA has the authority to define the scope of the source categories, determine the pollutants for which standards should be developed, set the emission level of the standards, and distinguish among classes, types, and sizes within categories in establishing the standards.

CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years review and, if appropriate, revise'' the NSPS. However, the Administrator need not review any such standard if the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. When conducting a review of an existing performance standard, the EPA has the discretion and authority to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to reflect ''the degree of emission limitation achievable through the application of the BSER which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' The term ''standard of performance'' in CAA section 111(a)(1) makes clear that the EPA is to determine both the BSER for the regulated sources in the source category and the degree of emission limitation achievable through application of the BSER. The EPA must then, under CAA section 111(b)(1)(B), promulgate standards of performance for new sources that reflect that level of stringency. CAA section 111(b)(5) generally precludes the EPA from prescribing a particular technological system that must be used to comply with a standard of performance. Rather, sources can select any measure or combination of measures that will achieve the standard. CAA section 111(h)(1) authorizes the Administrator to promulgate ''a design, equipment, work practice, or operational standard, or combination thereof'' if in his or her judgment, ''it is not feasible to prescribe or enforce a standard of performance.'' CAA section 111(h)(2) provides the circumstances under which prescribing or enforcing a standard of performance is ''not feasible,'' such as, when the pollutant cannot be emitted through a conveyance designed to emit or capture the pollutant, or when there is no practicable measurement methodology for the particular class of sources.

Pursuant to the definition of new source in CAA section 111(a)(2), standards of performance apply to facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Under CAA section 111(a)(4), ''modification'' means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. Changes to an existing facility that do not result in an increase in emissions are not considered modifications. Under the provisions in 40 CFR 60.15, reconstruction means the replacement of components of an existing facility such that: (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility; and (2) it is technologically and economically feasible to meet the applicable standards. Pursuant to CAA section 111(b)(1)(B), the standards of performance or revisions thereof shall become effective upon promulgation.

B. How does the EPA perform the NSPS review?

As noted in section II.A. of this preamble, CAA section 111 requires the EPA to, at least every 8 years, review and, if appropriate, revise the standards of performance applicable to new, modified, and reconstructed sources. If the EPA revises the standards of performance, they must reflect the degree of emission limitation achievable through the application of the BSER considering the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements. CAA section 111(a)(1).

In reviewing an NSPS to determine whether it is ''appropriate'' to revise the standards of performance, the EPA evaluates the statutory factors, which may include consideration of the following information:

- Expected growth for the source category, including how many new facilities, reconstructions, and modifications may trigger NSPS in the future.
- Pollution control measures, including advances in control technologies, process operations, design or efficiency improvements, or other systems of emission reduction, that are ''adequately demonstrated'' in the regulated industry.
- Available information from the implementation and enforcement of current requirements indicating that emission limitations and percent reductions beyond those required by the current standards are achieved in practice.
- Costs (including capital and annual costs) associated with implementation of the available pollution control measures.
- The amount of emission reductions achievable through application of such pollution control measures.
- Any non-air quality health and environmental impact and energy requirements associated with those control measures.

In evaluating whether the cost of a particular system of emission reduction is reasonable, the EPA considers various costs associated with the particular air pollution control measure or a level of control, including capital costs and operating costs, and the emission reductions that the control measure or particular level of control can achieve. The Agency considers these costs in the context of the industry's overall capital expenditures and revenues. The Agency also considers cost effectiveness analysis as a useful metric and a means of evaluating whether a given control achieves emission reduction at a reasonable cost. A cost effectiveness analysis allows comparisons of relative costs and outcomes (effects) of 2 or more options. In general, cost effectiveness is a measure of the outcomes produced by resources spent. In the context of air pollution control options, cost effectiveness typically refers to the annualized cost of implementing an air pollution control option divided by the amount of pollutant reductions realized annually.

After the EPA evaluates the statutory factors, the EPA compares the various systems of emission reductions and determines which system is ''best,'' and therefore represents the BSER. The EPA then establishes a standard of performance that reflects the degree of emission limitation achievable through the implementation of the BSER. In doing this analysis, the EPA can determine whether subcategorization is appropriate based on classes, types, and sizes of sources, and may identify a different BSER and establish different performance standards for each subcategory. The result of the analysis and BSER determination leads to standards of performance that apply to facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Because the NSPS reflect the BSER under conditions of proper operation and maintenance, in doing its review, the EPA also evaluates and determines the proper testing, monitoring, recordkeeping and reporting requirements needed to ensure compliance with the emission standards.

C. What is the source category regulated in this final action?

The EPA first promulgated NSPS for the secondary lead smelting source category on March 8, 1974 (39 FR 9308). These standards of performance are codified in 40 CFR part 60, subpart L, and are applicable to sources that commence construction, modification, or reconstruction after June 11, 1973. These standards of performance regulate emissions of PM from blast and reverberatory furnaces and specifies limits for visible emissions (opacity) for blast and reverberatory furnaces and for pot (refining) furnaces. The EPA amended NSPS subpart L on October 6, 1975 (40 FR 46250) to remove a provision providing that the failure to meet the NSPS emissions limits due to the presence of uncombined water in the stack gases was not considered a violation. In March 1979, the EPA reviewed the NSPS and analyzed possible revisions to the NSPS; however, the review did not result in any revisions to the NSPS subpart L at that time.[1]

The secondary lead smelting source category consists of facilities that produce lead and lead alloys from lead-bearing scrap material. Lead is used to make various construction, medical, industrial, and consumer products such as batteries, glass, x-ray protection gear, and various fillers. The secondary lead smelting process consists of: (1) pre-

[1] See *https://nepis.epa.gov/Exe/ZyPDF.cgi/91010O7P.PDF?Dockey=91010O7P.PDF.*

processing of lead bearing materials, (2) melting lead metal and reducing lead compounds to lead metal in the smelting furnace, and (3) refining and alloying the lead to customer specifications.

At secondary lead smelting facilities, blast and reverberatory furnaces are used in the smelting processes, and pot furnaces are used in the refining process. The process exhaust from blast and reverberatory furnaces is a source of PM emissions, and emissions of PM also occur as process fugitives at various points during the smelting process, such as during charging and tapping of furnaces and refining processes. Entrainment of dry materials in ambient air due to material processing, vehicle traffic, wind erosion from storage piles, and other activities can also be a source of PM emissions.

Currently, there are 11 secondary lead smelting facilities in the United States and each facility operates furnaces that are subject to NSPS subpart L, which specifies that owners or operators of affected facilities must limit PM emissions from blast and reverberatory furnaces to not more than 50 milligrams per dry standard cubic meter (mg/dscm) or 0.022 grains per dry standard cubic feet (gr/dscf). Subpart L also specifies that visible emissions must not exceed 20 percent opacity from blast or reverberatory furnaces and 10 percent opacity from pot furnaces. Secondary lead smelting facilities use a variety of control devices (*e.g.,* baghouses, gas scrubbers), often in combination, to comply with the PM emissions and opacity limits of the NSPS.

The EPA proposed the current review and revisions of the secondary lead smelting source category NSPS subpart L on December 1, 2022 (87 FR 73708). We received four comment letters, including one from the industry trade association (the Association of Battery Recyclers, or ABR) and three from other stakeholders, during the comment period. Summaries of the more significant comments we timely received regarding the proposed rule and our responses are provided in this preamble. A summary of all other public comments on the proposal and the EPA's responses to those comments is available in *Summary of Public Comments and Responses on Proposed Rule: New Source Performance Standards for Secondary Lead Smelting (40 CFR part 60, subparts L and La) Best System of Emission Reduction Review, Final Amendments,* Docket ID No. EPA–HQ–OAR–2022–0481. In this action, the EPA is finalizing decisions and revisions pursuant to CAA section 111(b)(1)(B) review for the secondary lead smelting NSPS subpart L after our considerations of all the comments received.

III. What changes did we propose for the secondary lead smelting NSPS?

On December 1, 2022, the EPA proposed revisions to the NSPS for secondary lead smelters pursuant to CAA section 111(b)(1)(B) review of NSPS subpart L. In that action, the EPA proposed to establish a new subpart (40 CFR part 60, subpart La) applicable to affected sources that begin construction, reconstruction, or modification after December 1, 2022. The EPA proposed in the NSPS subpart La, revised standards for PM emissions and opacity for blast furnaces, reverberatory furnaces, and process fugitive emissions sources that apply at all times, including periods of SSM. The EPA proposed initial and periodic PM and opacity performance testing, recordkeeping, and reporting requirements. The EPA also proposed to revise the definitions for blast and reverberatory furnaces and added a new definition for pot furnaces.

The EPA also proposed to amend NSPS subpart L to clarify that NSPS subpart L applies to affected sources that commenced construction, reconstruction, or modification after June 11, 1973, and on or before December 1, 2022, and to update the NSPS furnace definitions, performance testing schedule, and monitoring, recordkeeping, and reporting requirements to be more consistent with the NESHAP (40 CFR part 63, subpart X). The EPA also proposed the IBR of an alternative method for determining opacity and the requirement for the submission of electronic performance test reports.

IV. What actions are we finalizing and what is our rationale for such decisions?

The EPA is finalizing revisions to the NSPS for secondary lead smelters pursuant to CAA section 111(b)(1)(B) review. The EPA is promulgating the NSPS revisions in a new subpart, 40 CFR part 60, subpart La. The revised NSPS subpart is applicable to affected sources constructed, modified, or reconstructed after December 1, 2022. This action also finalizes standards of performance in NSPS subpart La for PM emission and opacity that apply at all times including during periods of SSM and other proposed changes such as electronic reporting. Additionally, this action finalizes proposed revisions to the testing, monitoring, notification, recordkeeping, and reporting requirements, which are the same for both NSPS subparts L and La, and finalizes a definition for ''process fugitive emissions source'' in NSPS subpart La based on consideration of public comments.

A. Revised NSPS for Blast, Reverberatory, and Pot Furnaces

1. Proposed BSER for PM Emissions and Opacity

Based on the EPA's permit review and assessment of control costs and other CAA section 111 statutory considerations, the EPA proposed to identify for NSPS subpart La that the BSER for PM emissions and opacity from new, modified, or reconstructed blast furnaces is an afterburner followed by efficient particulate controls (*e.g.,* fabric filter that may be installed in series with a high efficiency particulate air (HEPA) filter and/or a venturi scrubber). For new, modified, or reconstructed reverberatory and pot furnaces, the EPA proposed that the BSER for PM emissions and opacity is efficient particulate controls (*e.g.,* fabric filter that may be installed in series with a HEPA filter, venturi scrubber and/or a wet electrostatic precipitator (WESP)).

Based on the available PM emissions and opacity data, the EPA proposed in NSPS subpart La that the standard of performance for blast and reverberatory furnaces that reflects the application of BSER is an emission limit of 10 mg PM/dscm. For pot furnaces, the EPA proposed in NSPS subpart La that the standard of performance that reflects the application of BSER is a PM emissions limit of 3 mg/dscm. The EPA also proposed that the standard of performance for opacity from blast, reverberatory, and pot furnaces emissions is 0 percent.

2. How the Final Revisions to BSER and the PM Emissions and Opacity Standards Differ From the Proposed Revisions

After considering the comments regarding the EPA's proposed BSER determinations for NSPS subpart La and the proposed PM emissions and opacity standards, the EPA is finalizing the BSER determinations and the PM standards for blast and reverberatory furnaces for NSPS subpart La, as proposed. However, after considering the comments and additional opacity data provided by one commenter, the EPA is finalizing the opacity limits for blast and reverberatory furnace in the final NSPS subpart La at 5 percent, rather than the proposed opacity standard of 0 percent. Also, the EPA is revising the PM limit for pot furnaces to address comments associated with the interaction of the proposed limit for pot furnaces with the NESHAP subpart X requirements. In the final NSPS subpart La (40 CFR 60.122a(a)), the EPA is promulgating a definition for ''process fugitives emission source'' (see the discussion in section IV.F. of this preamble) and finalizing an emissions limit for PM of 4.9 mg/dscm and an opacity limit of 5 percent from process fugitive emissions sources that includes emissions from pot furnaces, as well as other combined process fugitive emissions (*e.g.,* emissions from furnace charging and tapping and casting).

3. BSER and PM Emissions and Opacity Standards Comments and Responses

a. BSER Determination

Comment: One commenter disagreed with the EPA's determination in the proposal preamble (87 FR 73715) that the BSER for PM emissions and opacity from new, modified, or reconstructed blast furnaces is an afterburner followed by efficient PM controls (*e.g.,* fabric filter installed in series with a high-efficiency particulate air (HEPA) filter and/or a venturi scrubber). The commenter noted that secondary lead smelting facilities use afterburners primarily to reduce emissions of carbon monoxide and unburned hydrocarbons from certain types of furnaces and configurations (*e.g.,* blast furnaces, collocated reverberatory furnaces) and that afterburners have little if any role in reducing emissions of PM.

Response: The EPA disagrees with the commenter's assertion that BSER for PM emissions and opacity from new, modified, or reconstructed blast furnaces should not include an afterburner. The afterburner helps to prevent fouling of the fabric filter by organics and moisture in the furnace exhaust, which results in better PM control. This determination is consistent with the BSER discussed in previous Secondary Lead Smelting NSPS review documents. For example, Volume 1 of the NSPS background document (June 1973, Air Pollution Technical Data (APTD)-1352a) states that the blast furnace afterburner is used upstream of the baghouse to ''incinerate oily and sticky materials to avoid binding the fabric.'' Additionally, the March 1979 NSPS review document (EPA–450/3–79–015) states that, ''As previously noted, with blast furnaces an afterburner is employed to ensure complete combustion of such material [sparks and other burning material in furnace gas] before it enters the baghouse.'' The commenter did not provide any additional information to contradict this long-standing analysis of the benefits of using in blast furnaces an afterburner to further reduce PM emissions.

b. Opacity Emission Limits for NSPS Subpart La

Comment: One commenter contended that the EPA based the proposed standard of 0 percent opacity limit for blast, reverberatory, and pot furnaces on insufficient information and limited data. The commenter also said that the EPA did not evaluate opacity measurements across the affected sources and under different operating conditions (particularly SSM periods).

In response to the EPA's request in the proposal for comments regarding the available opacity data for blast, reverberatory, and pot furnaces, the commenter provided a subset of opacity data measured in a common stack utilizing a continuous opacity monitor system (COMS) at the outlet of the baghouses before the scrubber (the commenter asserted a claim of CBI over the baghouse data). The commenter stated that the baghouse data demonstrate the presence of non-zero opacities during normal operations and contradict the EPA's proposed opacity limitation of 0 percent.

The commenter stated that the inherent subjectivity in the measurement of opacity precludes the EPA from establishing an absolute 0 percent opacity emissions standard. The commenter noted that the subjectivity of opacity measurements is acknowledged in the certification requirements for both EPA Method 9 and ASTM D7520–16 (*i.e.,* >15 percent opacity at any single plume reading or a >7.5 percent opacity average error in each plume category). The commenter added that ASTM D7520–16 references a repeatability (precision) study at 0 percent opacity of ±3 percent opacity (*i.e.,* at 0 percent opacity, ASTM D7520–16 will read between 0 percent opacity to 3 percent opacity 95 percent of the time), which could result in an exceedance of the 0 percent opacity standard. The commenter also noted that the proposed methodologies to determine opacity or visible emissions can be impacted by limitations in contrasting backgrounds and by the presence of wet plumes, which vary from source to source.

To account for the subjectivity and the margin of error associated with the proposed compliance test methods presented above, the commenter stated that the EPA should revise the proposed opacity limit to 5 percent.

Response: The EPA acknowledges that, on occasion during process operations and particularly during startup and shutdown events, brief periods of visible emissions from these sources are possible. However, since these sources are located in negative pressure locations, these periods of visible emissions should not typically occur. As such, to account for the remote possibility of these periods of visible emissions, limited data availability, and the subjectivity and margin of error of the visible emissions test methods, we are finalizing a visible emission standard of no greater than 5 percent over a single 6-minute averaging period. The 5 percent value ''threshold'' is the lowest visible emission increment reading achievable by EPA Method 9 that is greater than 0 percent, and the 6-minute averaging period represents the minimum number of visible emissions observations prescribed by EPA Method 9 to calculate a valid visible emissions average (*i.e.,* a minimum of 24 visible emissions observations shall be made at 15-second intervals). This opacity standard and averaging period accounts for brief periods of visible emissions while still maintaining stringency with the expected absence of emissions in a negative pressure environment.

To verify this, a 6-minute EPA Method 22 visible emissions check should occur at a minimum of once per calendar day during normal operations, as well as during each SSM event. If any visible emissions are observed for any period of time (*i.e.,* >0 seconds), a 30-minute EPA Method 9 visible emissions test must be conducted as soon as practicable. As an alternative, a 30-minute EPA Method 9 visible emissions test can be performed at a minimum of once per calendar day during normal operations, as well as during each SSM event without having to perform the EPA Method 22 visible emissions check. If any rolling 6-minute averaging period from the 30-minute visible emissions test is greater than 5 percent, corrective action must be initiated within 1 hour of detecting visible emissions above the applicable limit. After the corrective action is completed, an additional 30-minute visible emissions test must be performed. After the corrective action is completed, if any rolling 6-minute averaging period from the follow-up 30-minute visible emissions test is greater than 5 percent, the source is deemed out of compliance with the prescribed opacity standard.

Comment: One commenter noted an apparent typographical error in the proposed NSPS subpart La (40 CFR 60.122a) and suggested that the EPA change the text from ''Exhibit 0 percent opacity or greater'' to ''Exhibit opacity greater than'' the limit.

Response: The EPA has revised the text in NSPS subpart La 40 CFR

60.122a(a)(2) and 60.122a(b)(2) to address the typographical error.

c. PM Emissions Limit for Pot Furnaces

Comment: One commenter stated that the proposed rule's treatment of ''pot furnaces,'' including the establishment of PM standards for new pot furnaces, is misaligned with the functioning of pot furnaces at secondary lead smelters and with their treatment under other regulatory provisions, including NESHAP subpart X. The commenter said that NESHAP subpart X regulates pot furnace emissions as process fugitives, which are typically combined with emissions from other sources for ducting to controls, and that isolating pot furnace emissions for the purpose of performance testing may not be practical. The commenter said that the EPA should remove the proposed PM standard for pot furnaces.

The commenter stated that NESHAP subpart X (40 CFR 63.542) considers pot furnaces to be a process fugitive emissions source, rather than a process emissions source. The commenter noted that facilities may mix emissions from pot furnaces with process emissions from the smelting furnaces which makes it more difficult to segregate pot furnace emissions for compliance determination purposes. If the EPA does establish NSPS subpart La emission standards for new pot furnaces at secondary lead smelters, the commenter asserted that the EPA should clarify that commingled emissions from smelting furnaces and pot furnaces are subject to the proposed emission standards in 40 CFR 60.122a(a).

The commenter contended that the data the EPA used to establish the proposed PM emissions limit for pot furnaces are insufficient because the data include contributions from emission sources other than pot furnaces (*e.g.,* casting emissions).

The commenter also stated that the EPA should confirm that smaller refining kettles used for research and development (R&D) are excluded from the proposed definition of pot furnaces. For example, the EPA could exclude such kettles by establishing a size limit (*e.g.,* smaller than 5 tons of molten metal at maximum capacity) and a usage limit (operated fewer than 4000 hours per year). The commenter noted that the R&D refining kettles are a fraction of the size of normal production refining kettles (*e.g.,* 1 ton v. 100 tons) and are, therefore, insignificant emission sources at smelters.

Response: The EPA disagrees with commenter's statement that the final rule should not include a PM standard for pot furnaces. As noted in sections IV.A.1. and 2. of this preamble, the EPA has determined that the final BSER for PM emissions and opacity from new, modified, or reconstructed pot furnaces is efficient particulate controls, and the commenter does not dispute that PM emissions from pot furnaces can be reduced by application of these controls. Consequently, the EPA must establish a PM emissions limit that reflects BSER. However, the EPA acknowledges that isolating pot furnace emissions for NSPS compliance testing may not be feasible for all secondary lead smelting facilities. The EPA also acknowledges that the limited data the EPA used to establish the proposed PM emissions limit for pot furnaces include contributions from emission sources other than pot furnaces (*i.e.,* data from 5 of 6 test reports used to calculate the proposed pot furnace limit included contributions from casting fugitives).

To address the commenter's concern related to isolating emissions for compliance testing and the limited data set, the EPA conducted a further evaluation of the available test data to identify data values that included contributions from pot furnaces combined with other process fugitive sources (*e.g.,* emissions from furnace charging and tapping and casting). The EPA used this data set of comingled pot furnace emissions, which consists of 45 test runs from 3 facilities (Clarios, South Carolina; Gopher Resource, Florida; and Gopher Resource, Minnesota), to derive a PM emissions limit for pot furnace emissions combined with emissions from other process fugitives. Based on this updated analysis, in the final NSPS subpart La (40 CFR 60.122a(a)), the EPA is promulgating a process fugitive source emissions limit for PM of 4.9 mg/dscm from the process emissions control devices. This analysis can be found in the Particulate Matter Emissions Test Data Memorandum for Process Fugitive Sources as Secondary Lead Smelting Facilities located in the docket for this rulemaking. This approach of regulating pot furnace emissions as a process fugitive source is consistent with the approach used under NESHAP subpart X, which requires that new or reconstructed sources must capture all process fugitive emissions (including pot furnace emissions) with hoods or negative pressure enclosures and route those emissions to a control device.

Regarding the commenter's assertion that the EPA should confirm that smaller refining kettles used for R&D are excluded from the proposed definition of pot furnaces, the commentor did not provide any data demonstrating that R&D kettles cannot meet the proposed requirement. Additionally, the EPA is not finalizing the proposed definition for pot furnaces and is finalizing a process fugitive emissions limit. Therefore, the EPA has no basis to provide an exception to the emissions limits specified in NSPS subpart La at this time. However, the EPA may revisit this issue under the NESHAP subpart X review.

B. NSPS Subpart La Without Startup, Shutdown, and Malfunction Exemptions

Consistent with *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the EPA has established standards in NSPS subpart La that apply at all times. We are finalizing in NSPS subpart La specific requirements at 40 CFR 60.122a(c) that override the general provisions for SSM requirements. In finalizing the standards in NSPS subpart La, the EPA has taken into account startup and shutdown periods and, for the reasons explained in this section of the preamble, has not finalized alternate standards for those periods.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. Malfunctions, in contrast, are neither predictable nor routine. Instead, they are, by definition, sudden, infrequent, and not reasonably preventable failures of emissions control, process, or monitoring equipment (40 CFR 60.2). The EPA interprets CAA section 111 as not requiring emissions that occur during periods of malfunction to be factored into development of CAA section 111 standards. Nothing in CAA section 111 or in case law requires that the EPA consider malfunctions when determining what standards of performance reflect the degree of emission limitation achievable through ''the application of the best system of emission reduction'' that the EPA determines is adequately demonstrated. While the EPA accounts for variability in setting emissions standards, nothing in CAA section 111 requires the Agency to consider malfunctions as part of that analysis. The EPA is not required to treat a malfunction in the same manner as the type of variation in performance that occurs during routine operations of a source. A malfunction is a failure of the source to perform in a ''normal or usual manner'' and no statutory language compels the EPA to consider such events in setting CAA section 111 standards of performance. The EPA's approach to malfunctions in the analogous circumstances (setting ''achievable'' standards under CAA section 112) has been upheld as reasonable by the D.C. Circuit in *U.S.*

Sugar Corp. v. *EPA,* 830 F.3d 579, 606–610 (2016).

1. Proposed SSM Provisions

The EPA proposed in NSPS subpart La that the PM emissions and opacity limits for blast, reverberatory, and pot furnaces apply at all times, including periods of SSM. The proposed NSPS subpart La included specific requirements at 40 CFR 60.122a(c) that would override the general provisions for SSM requirements.

2. How the Final Revisions to the SSM Provisions Differ From the Proposed Revisions

After considering the comment on the proposed SSM provisions, the EPA is finalizing in NSPS subpart La that the PM emissions and opacity limits for blast, reverberatory, and pot furnaces apply at all times, including periods of SSM, and is finalizing the SSM provision in 40 CFR 60.122a(c), as proposed.

3. SSM Provision Comment and Response

Comment: One commenter asserted that the EPA should not remove from NSPS subpart La the exception in the NSPS general provisions (40 CFR 60.8(c)) which states that emissions during SSM periods that exceed the applicable NSPS limit are not considered to be a violation of the applicable emission limit. The commenter noted that multiple rulings by the D.C. Circuit (*e.g., Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 398 (D.C. Cir. 1973); *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 432 (D.C. Cir. 1973); and *National Lime Ass'n* v. *EPA,* 627 F.2d 416, 431 n.46 (D.C. Cir. 1980)) have affirmed the EPA's historic approach of not requiring affected sources to meet NSPS emission limits during SSM events. The commenter stated that it would be arbitrary and capricious for the EPA to interpret *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), as preventing the EPA from exercising discretion in establishing an SSM exception in NSPS subpart La or as making an SSM exception inappropriate in NSPS subpart La on the current record.

Response: As discussed in more detail in the proposal, the EPA has determined that the reasoning in the court's decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), which vacated the SSM exemption in CAA section 112, applies equally to CAA section 111. Therefore, we disagree with the commenter on the applicability of this decision to CAA section 111. While the EPA recognizes the differences between the NESHAP and NSPS programs, the court in *Sierra Club* held that under section 302(k) of the CAA, emissions standards or limitations must be continuous in nature, and the definition of emission or standard in CAA section 302(k) and the requirement for continuous standards applies to both NESHAP and NSPS.

C. Testing and Monitoring Requirements

1. Proposed Testing and Monitoring Provisions

The EPA proposed requiring that facilities subject to 40 CFR part 60, subparts L and La conduct periodic PM testing of blast, reverberatory, and pot furnace emissions. The EPA also proposed under 40 CFR part 60, subpart La periodic testing of opacity from blast, reverberatory, and pot furnace emissions. The proposed amendments would allow facilities to request less frequent periodic PM testing, reduced from every 12 months to every 24 months, if the previous periodic compliance test demonstrates that PM emissions are 50 percent or less of the final emissions limit (*e.g.,* PM emissions from blast and reverberatory furnaces of 25 mg/dscm or less for facilities subject to 40 CFR part 60, subpart L).

To reduce the testing burden on facilities, the EPA also proposed allowing facilities to determine the PM emissions by either EPA Method 12 (Determination of Inorganic Lead Emissions from Stationary Sources) or EPA Method 29 (Determination of Metals Emissions from Stationary Sources). For determining opacity under NSPS subpart L, the EPA proposed allowing the use of ASTM, International (ASTM) D7520–16 (Standard Test Method for Determining the Opacity of a Plume in the Outdoor Ambient Atmosphere) as an alternative to EPA Method 9. For NSPS subpart La, the EPA proposed allowing the use of EPA Method 22 (Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares) if there are zero visible emissions as an alternative to EPA Method 9 or the ASTM D7520–16 method.

The EPA also proposed adding 40 CFR 60.124 and 40 CFR 60.124a (Monitoring requirements) to NSPS subparts L and La, respectively, to include some of the monitoring requirements specified in 40 CFR 63.548(a) through (i) (Monitoring requirements) of the NESHAP (40 CFR part 63, subpart X), including development of a standard operating procedures (SOP) manual for control devices used to reduce PM and opacity emissions.

2. How the Final Revisions to the Testing and Monitoring Provisions Differ From the Proposed Revisions

After considering the comments, the EPA is finalizing the testing and monitoring provisions, as proposed. In response to public comment regarding the appropriate level of the opacity standard, the EPA revised the proposed opacity standard from 0 percent to 5 percent (see the discussion in section IV.A. of this preamble). Although EPA Method 22 is used only to determine the absence of visual emissions (*i.e.,* zero percent opacity), rather than to determine non-zero readings (*e.g.,* 5 percent opacity), the EPA is retaining the use of EPA Method 22 as an alternative method to potentially reduce the testing burden on facilities. For example, a facility could use EPA Method 22 to demonstrate compliance with the final opacity limit of 5 percent by determining no visible emissions. However, if visible emissions are detected, the facility would need to proceed to use EPA Method 9 to confirm opacity is no more than 5 percent.

3. Testing and Monitoring Comments and Responses

Comment: One commenter contended that periodic PM testing is unnecessary and inappropriate, and would not discover any actionable information that would not be discovered through the regular performance testing for particulate lead required by NESHAP subpart X.

Response: The EPA disagrees with the commenter. The target pollutant of the periodic testing under NESHAP subpart X is lead, while the target pollutant for the NSPS is PM. The EPA concludes that it is appropriate to require periodic testing for PM to confirm affected facilities continue to comply with the PM limits. Codifying the testing requirements in the NSPS provides for periodic, direct assessments regarding facility compliance status with the PM limits in NSPS subparts L and La.

Comment: One commenter acknowledged that allowing facilities to conduct performance tests for NESHAP subpart X and NSPS subparts L and La, as applicable, through collection of a single sample will appropriately facilitate effective compliance. The commenter stated that, to assist in the clarity of implementing the proposed rule, the EPA should revise proposed 40 CFR 60.123 and 60.123a to clarify that smelters are to employ section 16.1 of EPA Method 12 or the specifications in EPA Method 29, as stated in section 1.2

of EPA Method 29, and detailed throughout EPA Method 29.

Response: The EPA added the test method sections cited by the commenter to the final rules.

Comment: One commenter noted that proposed NSPS subparts L and La (at 40 CFR 60.123(b)(2) and 60.123a(b)(2)) allow for facilities to request from the EPA Administrator an extension (up to 24 months) for conducting the periodic performance tests for facilities where the previous compliance tests measured PM emissions are 50 percent or less of the emissions limit (*e.g.,* for NSPS subpart L, 25 mg/dscm or less). The commenter asserted that, in practice, it is difficult for well-controlled smelters to obtain a timely decision from the EPA regarding the facility's request, which is essentially tantamount to an unjustified denial of the extension request. The commenter stated that the EPA should provide the testing extension upon receipt of the facility's request by the appropriate EPA regional office, rather than the facility having to wait for Administrator approval.

Response: The EPA disagrees with the commenter. Providing the performance testing extension based solely on the receipt of the facility's request would not be appropriate because it would not provide any opportunity for the EPA or delegated authority to verify the facility's assertion by reviewing the request and supporting documentation (*e.g.,* test report) before granting the testing extension. However, the EPA recognizes it is reasonable for a facility to expect to get a response as to whether the 24-month period is approved within a reasonable timeframe before their next compliance test. Therefore, the EPA has determined that it is appropriate to finalize a provision that would preserve the opportunity to review incoming requests, while encouraging the EPA or delegated authority to act within a reasonable timeframe so that facilities have adequate notice as to when the next compliance test will be required. Accordingly, the EPA is finalizing a provision that provides that the extension request will be deemed automatically approved under the following specified circumstances: (1) a facility completes a performance test that is 50 percent or lower than the applicable emissions limit, (2) the facility submits a request for the extension of 24 months well before their next required compliance test (*i.e.,* no more than 4 months after the subject compliance test that was 50 percent or lower than the limit), and (3) the EPA does not provide a response to such request within 6 months of receipt of such request. The EPA has determined that this provision will provide a balanced approach to the competing interests of all involved parties.

D. Electronic Reporting

The EPA is finalizing a requirement that owners and operators of secondary lead smelters subject to the NSPS subparts L and La submit the results of the initial and periodic performance tests electronically through the EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI). The EPA did not receive any public comments regarding the proposed requirements for electronic reporting.

E. Notification, Recordkeeping, and Reporting Requirements

1. Proposed Notification, Recordkeeping, and Reporting Provisions

The EPA proposed to add the notification, recordkeeping, and reporting requirements specified in the proposed 40 CFR 60.125 and 40 CFR 60.125a (Notification, recordkeeping, and reporting requirements) to NSPS subparts L and La, respectively. The proposed requirements clarified that facilities must comply with the notification and recordkeeping requirements specified in 40 CFR 60.7 and the reporting requirements specified in 40 CFR 60.19. The proposed requirements in NSPS subparts L and La included the recordkeeping requirements from NESHAP subpart X specified in 40 CFR 63.550(b); (c)(1) through (c)(4); (c)(11) through (c)(12); (e)(4) through (e)(7); and (e)(13).

2. How the Final Revisions to the Notification, Recordkeeping and Reporting Provisions Differ From the Proposed Revisions

After considering the comments, the EPA is finalizing the notification, recordkeeping and reporting provisions, as proposed, with the exception of the editorial changes made to the text of 40 CFR 60.125(a) and 60.125a(a); 40 CFR 60.124(c) and 60.124a(c); and 40 CFR 60.124(f)(4) and 60.124a(f)(4), as discussed below in section IV.E.3. of this preamble.

3. Notification, Recordkeeping, and Reporting Comments and Responses

Comment: One commenter stated that the EPA should clarify as to the proposed revisions to NSPS subpart L that certain aspects of the NSPS General Provisions 40 CFR 60.7 and 60.19 will not apply because they concern regulatory provisions that are absent from NSPS subpart L (*e.g.,* 40 CFR 60.7(a)(7) concerns continuous opacity monitoring systems, which appropriately are not required under proposed NSPS subpart L).

Response: The EPA revised the text of 40 CFR 60.125(a) and 60.125a(a) as set forth in the amendatory text portion of this final rule to address the clarification suggested by the commenter.

Comment: One commenter stated that the EPA should revise the proposed NSPS subparts L and La (40 CFR 60.124(c) and 60.124a(c)) to replace the phrase ''PM and opacity emissions control devices'' with the phrase ''baghouses (fabric filters or cartridge collectors)'' to improve the consistency between the underlying requirement proposed in 40 CFR 60.124(b) and 60.124a(b), and the submission provisions proposed in 40 CFR 60.124(c) and 60.124a(c).

Response: The EPA agrees with the editorial change suggested by the commenter. Therefore, the final NSPS subparts L and La (40 CFR 60.124(c) and 60.124a(c)) replace the phrase ''PM and opacity emissions control devices'' with the phrase ''baghouses (fabric filters or cartridge collectors).''

Comment: One commenter requested that the EPA provide a mechanism by which a secondary lead smelting facility could avoid submission of a redundant SOP manual in response to the proposed requirements in 40 CFR 60.124 and 60.124a, given the similarities between those provisions and the SOP required by NESHAP subpart X (40 CFR 63.548).

Response: The EPA disagrees with the commenter that an additional mechanism is needed that would allow secondary lead smelting facilities to avoid submission of redundant SOP manuals in response to the proposed requirements in 40 CFR 60.124 and 60.124a. Proposed 40 CFR 60.124(l) and 60.124a(l) state: ''If an affected source is subject to the monitoring requirements specified in 40 CFR part 63, subpart X (National Emissions Standards for Hazardous Air Pollutants from Secondary Lead Smelting) and those requirements are as stringent or more stringent than the monitoring requirements specified in paragraphs (a) through (j) of this section, compliance with the monitoring requirements specified in 40 CFR part 63, subpart X also demonstrates compliance with the monitoring requirements specified in paragraphs (a) through (k) of this section.'' The EPA believes that this specification in NSPS subparts L and La already addresses the concern raised by the commenter.

Comment: One commenter noted that proposed NSPS subparts L and La (40

CFR 60.124(f)(4) and 60.124a(f)(4)) refer to the document ‘‘Office of Air Quality Planning and Standards (OAQPS) Fabric Filter Bag Leak Detection Guidance’’ (EPA–454/R–98–015; September 1997). The commenter stated that the EPA guidance document is 26 years old and may be inconsistent with current guidance provided by manufacturers of bag leak detection systems. The commenter requested that the EPA revise proposed NSPS subparts L and La (40 CFR 60.124(f)(4) and 60.124a(f)(4)) to clarify that a smelter may install and operate the bag leak detection system in a manner consistent with the manufacturer's written specifications and recommendations if there is any conflict between the manufacturer's instructions and the OAQPS guidance.

Response: The EPA agrees with the clarification suggested by the commenter. Therefore, the final text of 40 CFR 60.124(f)(4) and 60.124a(f)(4) as set forth in the amendatory text portion of this final rule.

Comment: One commenter contended that the proposed requirements in NSPS subparts L and La (40 CFR 60.124(k), 60.124a(k), 60.125(c)(10), and 60.125a(c)(10)) for facilities to establish and record parametric monitoring values for each control device used to comply with the PM and opacity emission standards are not consistent with the requirements of NESHAP subpart X (40 CFR 63.550(a)), which only requires parametric monitoring and recordkeeping for scrubbers. The commenter stated that the proposed requirements in NSPS subparts L and La (40 CFR 60.124(k) and 60.124a(k)) for secondary lead smelting facilities to establish, during the initial or periodic performance test, the value or range of values of the monitoring parameter(s) for each control device used to comply with the PM and opacity emission standards was overly vague and potentially would require the establishment of monitoring parameters for pollution control devices (*e.g.,* WESPs) that are employed, but are not part of BSER, or afterburners that are employed, but have little or no role in PM control. The commenter added that the proposed NSPS subparts L and La include monitoring and recordkeeping provisions that provide sufficient criteria for the proper operation of applicable control devices (the commenter provided several citations to the proposed rules). The commenter stated that the EPA should revise the proposed language to specify that a secondary lead smelting facility is not required to establish and record parametric monitoring values for PM control devices (other than scrubbers) if the facility demonstrates compliance with NSPS subparts L and/or La (40 CFR 60.124 and/or 60.124a) by complying with the monitoring provisions of NESHAP subpart X.

Response: Although the EPA strives to improve the consistency between NSPS subparts L and La and NESHAP subpart X, where possible, the EPA's decision-making regarding the requirements for the NSPS must be driven by the requirements of CAA section 111 and the regulatory provisions necessary to implement standards of performance promulgated pursuant to that authority. We have determined that parametric monitoring of control devices is necessary for demonstrating ongoing compliance with the PM and opacity emission standards between the demonstrations provided by the periodic performance tests. We also disagree with the commenter that the text in proposed NSPS subparts L and La (40 CFR 60.124(k) and 60.124a(k)) is overly vague. The rules specify establishment of monitoring parameter values ‘‘for each control device used to comply with the PM and opacity emission standards’’ of the NSPS. Regarding the commenter's contention that the proposed text could potentially require the establishment of monitoring parameters for control devices (*e.g.,* WESP) and afterburners, this is consistent with the EPA's intent. The EPA determined that BSER for PM emissions and opacity from new, modified, or reconstructed blast furnaces is an afterburner followed by efficient PM controls, which would include controls such as a WESP.

Comment: One commenter said that the phrase ‘‘and those requirements are as stringent or more stringent than the monitoring requirements specified in paragraphs (a) through (j) of this section’’ in proposed NSPS subparts L and La (40 CFR 60.124(l) and 60.124a(l)) introduces regulatory confusion as to whether compliance with the monitoring provisions of NESHAP subpart X also demonstrates compliance with the proposed monitoring requirements of NSPS subparts L and La. The commenter asserted that the EPA should either eliminate the phrase from the regulatory text or, at a minimum, state in the preamble to the final NSPS rulemaking that the current monitoring provisions of NESHAP subpart X are as stringent or more stringent than the monitoring requirements specified in the proposed NSPS.

Response: The EPA believes that the current monitoring provisions of NESHAP subpart X are at least as stringent as the monitoring requirements specified in the final NSPS subparts L and La. Nonetheless, the EPA continues to find it appropriate to finalize the proposed language at 40 CFR 60.124(l) and 60.124a(l) with respect to the NESHAP subpart X monitoring requirements. NESHAP undergo periodic reviews pursuant to CAA section 112, and, to the extent that NESHAP subpart X were revised during a future review, or otherwise modified, such that the monitoring requirements were no longer as stringent or more stringent than those finalized in subparts L and La, it would no longer be appropriate to permit the use of the monitoring requirements in NESHAP subpart X in lieu of those required by the NSPS.

Comment: One commenter said that proposed NSPS subparts L and La (40 CFR 60.124 and 60.124a) require that the monitoring systems comply with the applicable requirements specified in the NSPS General Provisions (40 CFR 60.13) but noted that 40 CFR 60.13(a) states that the section is only applicable ‘‘upon promulgation of performance specifications for continuous monitoring systems under appendix B to this part.’’ The commenter contended that, because proposed NSPS subparts L and La do not require continuous monitoring systems to demonstrate compliance with emission limits, the EPA should revise the proposed language in 40 CFR 60.124 and 60.124a to include the following text: ‘‘The owner shall comply with the applicable monitoring requirements specified in 40 CFR 60.13 upon promulgation of performance specifications in 40 CFR part 60—Appendix B for the continuous monitoring systems required in this section. The Procedures of 40 CFR part 60—Appendix F do not apply because the continuous monitoring systems required in this section are not used to demonstrate compliance with emission limits on a continuous basis.''

Response: The EPA disagrees with the commenter that additional text is needed in 40 CFR 60.124 or 60.124a. As the commenter noted, 40 CFR 60.124 and 60.124a state that the owner shall comply with the *applicable* monitoring requirements specified in 40 CFR 60.13. Although the proposed NSPS subparts L and La do not require facilities to use continuous opacity monitoring systems (COMS) or continuous emissions monitoring systems (CEMS) to comply with the standards, NSPS subparts L and La do not preclude facilities from using COMS or CEMS. The performance standards are required if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis.

F. Definitions

1. Proposed Definitions

The EPA proposed to incorporate the definitions shown in Table 1 of this preamble into 40 CFR 60.121 (Definitions) of existing 40 CFR part 60, subpart L and 40 CFR 60.121a (Definitions) of the proposed 40 CFR part 60, subpart La. These proposed definitions were intended to improve the clarity of the NSPS subparts and to reduce potential confusion among industry and regulatory agencies by aligning the descriptions of the affected sources that would be regulated by 40 CFR part 60, subparts L and La to be more consistent with the definitions within the NESHAP at 40 CFR part 63, subpart X, as shown in Table 1. These proposed changes did not affect the applicability of existing NSPS subpart L.

TABLE 1—PART 60 PROCESS EQUIPMENT DEFINITIONS PROPOSED FOR NSPS SUBPARTS L AND La

Equipment	Current definition in NSPS subpart L	NESHAP subpart X	Proposed for NSPS subparts L and La
Blast furnace	Any furnace used to recover metal from slag.	A smelting furnace consisting of a vertical cylinder atop a crucible, into which lead-bearing charge materials are introduced at the top of the furnace and combustion air is introduced through tuyeres at the bottom of the cylinder, and that uses coke as a fuel source and that is operated at such a temperature in the combustion zone (greater than 980 Celsius) that lead compounds are chemically reduced to elemental lead metal.	A smelting furnace consisting of a vertical cylinder atop a crucible, into which lead-bearing charge materials are introduced at the top of the furnace and combustion air is introduced through tuyeres at the bottom of the cylinder, and that lead compounds are chemically reduced to elemental lead metal.
Reverberatory furnace	Includes the following types of reverberatory furnaces: stationary, rotating, rocking, and tilting.	A refractory-lined furnace that uses one or more flames to heat the walls and roof of the furnace and lead-bearing scrap to such a temperature (greater than 980 Celsius) that lead compounds are chemically reduced to elemental lead metal.	A refractory-lined furnace that uses one or more flames to heat the walls and roof of the furnace and lead-bearing scrap such that lead compounds are chemically reduced to elemental lead metal. Reverberatory furnaces include the following types: stationary, rotating, rocking, and tilting.
Pot furnace	Not defined	Refining kettle means an open-top vessel that is constructed of cast iron or steel and is indirectly heated from below and contains molten lead for the purpose of refining and alloying the lead. Included are pot furnaces, receiving kettles, and holding kettles.	Pot furnace is a type of refining kettle, which is an open-top vessel constructed of cast iron or steel and is indirectly heated from below and contains molten lead for the purpose of refining and alloying the lead.

2. How the Final Rule Definitions Differ From the Proposed Definitions

After considering the comments on the proposed definitions, the EPA is not adopting the proposed changes to the definitions for blast furnace, reverberatory furnace, and pot furnace in current NSPS subpart L. For NSPS subpart La, the EPA is maintaining in 40 CFR 60.121a (Definitions) the definitions of ''blast furnace,'' ''lead,'' ''reverberatory furnace,'' and ''secondary lead smelter'' specified in current NSPS subpart L (instead of adopting the proposed definitions in Table 1, above) and finalizing the definition of ''process fugitive emissions source.'' Table 2 of this preamble shows the final process definitions for NSPS subpart La.

TABLE 2—PART 60 FINAL DEFINITIONS FOR NSPS SUBPART LA

Equipment	Final NSPS subpart La
Blast furnace	Blast furnace means any furnace used to recover metal from slag.
Lead	Lead means elemental lead or alloys in which the predominant component is lead.
Reverberatory furnace	Reverberatory furnace includes the following types of reverberatory furnaces: stationary, rotating, rocking, and tilting.
Process fugitive emissions source	A source of PM emissions at a secondary lead smelter that is associated with lead smelting or refining including, but not limited to, smelting furnace charging points; smelting furnace lead and slag taps; pot and refining furnaces; and casting kettles.

3. Definition Comments and Responses

Comment: One commenter provided several comments and recommendations regarding the proposed definitions in NSPS subparts L and La. The commenter said that the EPA should revise the proposed definition of ''secondary lead smelter'' to use the term ''lead-bearing material'' rather than ''lead-bearing scrap material'' and either include or cross-reference the definition of ''lead bearing material'' from NESHAP subpart X (40 CFR 63.542). The commenter noted that the proposed definitions in NSPS subparts L and La did not define either ''lead-bearing material'' or ''lead-bearing scrap material.'' The commenter said that the EPA should clarify that these terms in the proposed definitions of ''blast furnace'' and ''reverberatory furnace'' (40 CFR 60.121(a) and 60.121a(a)), mean the same as ''lead-bearing material'' as defined in NESHAP subpart X (40 CFR 63.542).

The commenter stated that the EPA should align the proposed definition of ''blast furnace'' in 40 CFR 60.121(d) and 60.121a(d) with the NESHAP definition for ''blast furnace'' used in NESHAP subpart X (40 CFR 63.542) by including the phrases ''uses coke as a fuel source'' and ''(greater than 980 Celsius)'' to eliminate potential confusion about applicability and the possibility of any gaps between the NESHAP and NSPS definitions. The commenter said that the EPA should align the proposed definition of ''reverberatory furnace'' in NSPS subparts L and La (40 CFR 60.121(a) and 60.121a(a)) with the NESHAP subpart X definition by excluding the last sentence of the proposed definition to eliminate potential confusion about applicability and the possibility of any gaps between the NESHAP and NSPS definitions: ''Reverberatory furnaces include the following types: stationary, rotating, rocking, and tilting furnaces.''

The commenter said that the proposed definitions for ''lead'' in NSPS subparts L and La (40 CFR 60.121(c) and 60.121a(c)) should include the term ''lead alloy,'' rather than ''alloy,'' because ''alloy'' arguably could refer to certain unspecified non-lead alloys. The commenter stated that the EPA should change the term ''alloy'' to ''lead alloy'' and add the definition of ''lead alloy'' from NESHAP subpart X (40 CFR 63.542) to NSPS subparts L and La.

The commenter also noted that the proposed NSPS subparts L and La did not define the term ''smelting'' used in the proposed secondary lead smelter definition and said that the EPA should either include or cross-reference the definition of ''smelting'' from NESHAP subpart X (40 CFR 63.542).

The commenter asserted that the EPA should clarify that, for a refining kettle that meets the pot furnace definition, the new pot furnace includes all of the typical refining kettle components including (as applicable): footers, structural steel, kettle or pot (constructed of cast iron or steel), indirect heating system (burners, piping, monitors, combustion air system, and flue), cover, fume collection system (hood), agitator (mixer, motor, drive, and mount), furnace shell, refractory lining, lead pump, electrical components (switches, controllers, etc.), and process monitors. The commenter noted that this clarification is important because facilities regularly replace both the kettle and the refractory lining component of the pot furnace during the pot furnace's useful life and replacing the kettle or the refractory lining of a pot furnace potentially could be misinterpreted as reconstruction without appropriate clarification on this issue.

The commenter also stated that the EPA should revise the definition of ''pot furnace'' at proposed 40 CFR 60.121(e) and 60.121a(e) as follows to clarify that the definition does not apply to receiving kettles, holding kettles, or R&D kettles: ''(e) Pot furnace means a type of refining kettle, which is an open-top vessel constructed of cast iron or steel and is indirectly heated from below and contains molten lead for the purpose of refining and alloying the lead. For avoidance of doubt, the term ''pot furnace'' excludes the following types of refining kettles: (i) receiving kettles and holding kettles where refining or alloying activities do not occur; and (ii) pot furnaces with a maximum capacity less than 5 tons molten metal that are operated fewer than 4000 hours per year.''

The commenter noted that the important distinction between pot furnaces used for refining and alloying, on the one hand, and refining kettles used for receiving or holding molten lead, on the other hand, is not present in the proposed rule. Instead, the commenter said that the EPA proposed a definition of pot furnaces in 40 CFR 60.120(e) and 60.120a(e) as ''a type of refining kettle, which is an open-top vessel constructed of cast iron or steel and is indirectly heated from below and contains molten lead for the purpose of refining and alloying the lead.''

Response: These proposed definitions were intended to improve the clarity of the NSPS subparts and to reduce potential confusion among industry and regulatory agencies by aligning the descriptions of the affected sources that would be regulated by NSPS subparts L and La to be more consistent with the definitions within the NESHAP subpart X. However, after considering the comments received regarding the proposed process equipment definitions and because of potential future changes to the definitions in NESHAP subpart X pursuant to the EPA's upcoming review of NESHAP subpart X, which applies to new and existing sources, the EPA is not finalizing the proposed process equipment definition changes in subpart L and La. The EPA had determined that it is more appropriate to complete the NESHAP review first before finalizing any changes to the existing definitions in NSPS subparts L and La for blast furnace, lead, reverberatory furnace, and secondary lead.

As part of the NESHAP review process, the EPA will acquire new information regarding secondary lead process equipment, which could result in revisions to the existing NESHAP definitions or development of new definitions. Were the EPA to finalize the proposed definitions in NSPS subparts L and La at this time, such future revisions to the definitions in NESHAP subpart X may create new inconsistencies. In this case, finalizing the proposed definitions to NSPS subparts L and La would not increase clarity and consistency as intended. Instead, any definition changes made in NSPS subparts L and La at this time with the intent of improving the consistency between the NSPS and NESHAP definitions would be mistimed, and the EPA might need to consider further revising the NSPS definitions established in this action in the future to reflect the equipment definitions specified in the post-review NESHAP. Because the EPA has decided not to finalize the revised definitions, the EPA does not need to provide detailed responses to the comments suggesting specific revisions to those definitions.

In addition, after revisiting the process definitions that have been in NSPS subpart L since 1983, we find that no changes are needed to improve clarity as initially thought at proposal. Therefore, we are not finalizing any changes to the existing definitions in NSPS subpart L or in NSPS subpart La. Instead, we are maintaining the blast furnace, lead, reverberatory furnace, and secondary lead smelter definitions currently specified in NSPS subpart L. However, we are adding to NSPS subpart La a definition for ''process fugitive emissions source'' to accommodate the final PM standard for pot furnaces (see the discussion in section IV.A.2. of this preamble). Also, regarding the comments that the EPA should include the term ''lead alloy,'' rather than ''alloy,'' the current subpart L and new subpart La both state that ''*Lead* means elemental lead or alloys in which the predominant component is lead.'' This definition is clear that the only alloys affected by the rule are alloys in which the predominant component is lead. The term ''alloys in which the predominant component is lead'' essentially means the same thing as ''lead alloys''. Therefore, we did not make any changes to the definition of lead or add a new definition for lead alloys to subparts L or La.

With regard to the comment that the EPA should include a definition of smelting or provide a cross reference, because of potential future changes to the definitions in NESHAP subpart X (including for ''smelting'') pursuant the EPA's upcoming review of NESHAP subpart X (discussed above), which applies to new and existing sources, the EPA decided not to add a new definition for smelting in subpart L or La at this time because of potential inconsistencies once the EPA completes the next NESHAP review.

Regarding the comment that EPA should revise the definition of ''pot furnace'', this may have been an important clarification for the NSPS final rule if the EPA finalized the proposed pot furnace specific emissions limit of 3 mg/dscm. However, as explained in a previous response, instead of a pot furnace specific limit, the EPA is promulgating a PM limit of 4.9 mg/dscm for process fugitive emissions, which includes pot furnaces, but also includes other process fugitive emissions sources (such as refining kettles, holding kettles, alloying units). Therefore, we conclude that the specific definition clarifications requested by the commenter are no longer necessary for implementation of the NSPS and can wait until the EPA completes the next NESHAP review.

G. Effective Date and Compliance Dates

Pursuant to CAA section 111(b)(1)(B), the effective date of the final rule requirements in NSPS subpart La and amendments to NSPS subpart L will be the promulgation date, which is the date of publication of the final rule in the **Federal Register**. Affected sources that commence construction, reconstruction, or modification after December 1, 2022, must comply with all requirements of NSPS subpart La no later than the effective date of the final rule or upon startup, whichever is later.

V. Summary of Cost, Environmental, and Economic Impacts

A. What are the air quality impacts?

The final amendments to 40 CFR part 60, subpart La:

- Reduce the PM emissions limit for blast and reverberatory furnaces from 50 to 10 mg/dscm.
- Establish new PM emissions limits for process fugitive emissions sources of 4.9 mg/dscm.
- Lower the opacity limit for blast and reverberatory furnaces from 20 percent to 5 percent.
- Lower the opacity limit for pot furnaces from 10 percent to 5 percent.

New or reconstructed blast, reverberatory, and pot furnaces will also be subject to the NESHAP (40 CFR part 63, subpart X) requirements for new sources, while modified blast, reverberatory, and pot furnaces will also be subject to the NESHAP requirements for existing sources. NESHAP subpart X regulates particulate lead emissions from process vent, process fugitive, and fugitive dust sources. The emissions capture systems and control devices that are already required by the NESHAP to comply with the lead limits for blast furnaces, reverberatory furnaces, and process fugitive emissions sources will also control PM emissions regulated by the NSPS. Therefore, the final 40 CFR part 60, subpart La will not result in actual reductions of PM emissions. However, codifying the lower PM and opacity limits in the final 40 CFR part 60, subpart La will significantly reduce the PM and opacity allowable emissions of affected sources that commence construction, reconstruction, or modification after December 1, 2022.

B. What are the secondary impacts?

Indirect or secondary air emissions impacts result from the increased energy usage associated with the operation of control devices (*e.g.,* increased secondary emissions of criteria pollutants from electricity generating power plants). The EPA does not expect that facilities will need any additional control devices or other equipment to meet the final NSPS requirements beyond those that would already be needed to comply with the NESHAP. Therefore, the EPA does not attribute any secondary impacts to the final 40 CFR part 60, subpart La.

C. What are the cost impacts for regulated facilities?

For 40 CFR part 60, subparts L and La, the EPA requires that facilities conduct periodic performance tests to measure PM emissions using EPA Method 5 (Determination of Particulate Matter Emissions from Stationary Sources). The NESHAP (40 CFR part 63, subpart X) also requires periodic tests for lead using EPA Method 12 (Determination of Inorganic Lead Emissions from Stationary Sources) or EPA Method 29 (Metal Emissions from Stationary Sources). Because both of the NESHAP test methods analyze the PM captured on the internal surfaces of the sampling probe and on a sampling train filter to determine the lead concentration, facilities can conduct an additional gravimetric analysis of the EPA Method 12 or EPA Method 29 probe rinse and filter to determine PM emissions, rather than performing separate tests using EPA Method 5. The EPA estimates that the additional gravimetric analysis of the EPA Method 12 or EPA Method 29 particulate filter costs approximately $300 per test per year. To estimate the total cost associated with the final periodic PM performance tests under 40 CFR part 60, subparts L and La, the EPA assumed that each respondent under the respective subparts would conduct 3 p.m. tests per year (1 for each furnace type). See section V.C. of this preamble for more details on cost estimates.

For 40 CFR part 60, subpart La, the EPA is also requiring that facilities periodically determine the opacity of blast furnace, reverberatory furnace, and process fugitive source emissions. For NSPS subpart La, the EPA is requiring that facilities conduct initial and periodic tests using EPA Method 9 or ASTM D7520–16. Alternatively, facilities can use EPA Method 22 (Visible Determination of Fugitive Emissions) to determine no visible emissions from blast furnace, reverberatory furnace, and process fugitive emissions sources. To estimate the cost of the initial and periodic opacity tests for NSPS subpart La, the EPA assumed that new facilities would be able to determine no visible emissions using EPA Method 22, rather than using EPA Method 9. The EPA assumed that new facilities would train facility personnel to implement EPA Method 22 (at a one-time cost of $426 per facility), but not incur additional capital costs associated with conducting the EPA Method 9 observations.

We estimate that 2 of the 11 existing facilities will be modified or reconstructed over the next five years such that these 2 facilities will be subject to subpart La, and the other 9 facilities will be subject to subpart L. Therefore, for 40 CFR part 60, subpart L, the total incremental cost for the periodic PM testing over the 3-year period is $16,200 three tests per year at $300 per test for 9 respondents for years 2 and 3 (facilities subject to subpart L have already conducted initial performance tests for PM emissions and opacity). For 40 CFR part 60, subpart La, the total incremental cost for PM testing over the 3-year period is $8,100 (*i.e.,* three tests per year at $300 per test for the two existing facilities that the EPA assumes will undergo reconstruction and one new facility) and the total incremental cost for opacity testing is $426 for EPA Method 22 training (*i.e.,* $426 one-time cost for the new facility). Based on a review of facility operating permits, the two existing facilities that we determined could be reconstructed over the 3-year period (thereby triggering NSPS subpart La applicability) already conduct periodic opacity tests using EPA Method 9. Therefore, the EPA did not estimate opacity testing costs for the two potential reconstructed facilities. The estimated total incremental cost for emissions testing for two reconstructed sources and one new source projected over the 3-year period is $8,526.

The EPA did not estimate cost impacts for the final monitoring requirements in 40 CFR part 60, subparts L and La because this action will allow subject facilities to comply with these subparts by complying with the applicable monitoring requirements for new sources specified in the NESHAP (40 CFR part 63, subpart X). Therefore, there is no additional monitoring burden.

D. What are the economic impacts?

The EPA conducted an economic impact analysis (EIA) and small business screening assessment for this final action, as discussed in the proposal for this action and detailed in the memorandum, *Economic Impact Analysis for Final Revisions and Amendments to the New Source Performance Standards for Secondary Lead Smelters,* which is available in the docket for this action. The economic impacts of this final action were estimated by comparing total annualized compliance costs to revenues at the ultimate parent company level. This is known as the cost-to-revenue or cost-to-sales test. This ratio provides a measure of the direct economic impact to ultimate parent company owners of facilities while presuming no impact on consumers.

As discussed in the proposal for this action, we estimate that the total cost for emissions testing, reporting, and recordkeeping projected over the 3-year period for the 9 sources subject to NSPS subpart L is $80,000. The average annual cost per facility is approximately $3,000. The 9 facilities subject to NSPS subpart L are owned by seven different parent companies with an annual average revenue of $4.5 billion in 2021. As discussed in section V.C. of this preamble, we assume the other 2 existing facilities will be modified or reconstructed and therefore will be subject to subpart La. The economic impact associated with this cost as an annual cost per sales, for the average parent company in the industry, is less than 0.0001 percent and is not expected to result in a significant market impact, regardless of whether it is fully passed on to the consumer or fully absorbed by the affected firms.

In addition, the cost analysis assumed that facilities subject to final 40 CFR part 60, subpart La would conduct initial and periodic tests for PM emissions and opacity, but would not need to install control devices to meet the final PM and opacity emissions limits because the new, modified, or reconstructed facility would install the same types of controls already necessary to comply with NESHAP subpart X. The EPA also assumed that facilities subject to the final NSPS subpart La would not incur monitoring costs attributed to the new NSPS.

The EPA views the testing costs to be upper-bound estimates on the potential compliance costs of the final 40 CFR part 60, subparts L and La. Even under the upper-bound cost assumptions described above, the EPA expects the potential economic impacts of this final action will be small.

As required by the Regulatory Flexibility Act (RFA), we performed an analysis to determine if any small entities might be disproportionately impacted by the final requirements. The EPA does not know with certainty which existing facilities may be reconstructed or modified in the future and subject to NSPS subpart La, and therefore cannot perform an accurate cost-to-sales analysis. However, based on an assessment of the projected growth in the secondary lead smelting industry, the EPA believes it is unlikely that any future facilities will be reconstructed or modified by a small business.

E. What are the benefits?

The final revisions to 40 CFR part 60, subparts L and La clarify both rules, improve the practical enforceability of the rules, and enhance compliance and enforcement. The EPA expects that implementing the final amendments to 40 CFR part 60, subparts L and La will help ensure that control systems used to reduce PM and opacity emissions from affected sources are properly operated and maintained over time.

Additionally, the final amendments to require electronic reporting of emissions test results in 40 CFR part 60, subparts L and La will ultimately reduce the burden on regulated facilities, delegated air agencies, and the EPA, and also improve access to data, minimize data reporting errors, and eliminate paper waste and redundancies.

F. What analysis of environmental justice did we conduct?

Executive Order 12898 directs the EPA to identify the populations of concern who are most likely to experience unequal burdens from environmental harms, which are specifically minority populations (people of color), low-income populations, and Indigenous peoples (59 FR 7629; February 16, 1994). Additionally, Executive Order 13985 is intended to advance racial equity and support underserved communities through Federal government actions (86 FR 7009; January 20, 2021). The EPA defines environmental justice (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.'' [2] 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.'' In recognizing that people of color and low-income populations 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,*[3] 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 minority populations, low-income populations, and/or indigenous peoples; (2) exacerbate existing disproportionate impacts on minority populations, low-income populations, and/or indigenous peoples; or (3) present opportunities to address existing disproportionate impacts on minority populations, low-income populations, and/or indigenous peoples through this action under development.

The Agency has conducted an analysis of the demographics of the populations living near existing facilities in the Secondary Lead Smelting source category. Because this action finalizes standards of performance for new, modified, and reconstructed sources that commence construction after December 1, 2022, the locations of the construction of new secondary lead smelters are not known. As discussed above, we assumed two existing facilities might be modified. However, it is not known with any

[2] See *https://www.epa.gov/environmentaljustice.*

[3] See *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

certainty which of the existing secondary lead smelters might be modified or reconstructed. Therefore, the demographic analysis was conducted for the 11 existing secondary lead smelters as a proxy for the characterization of the demographics in areas where new, modified, or reconstructed source might be located in the future.

Section F. (''What analysis of environmental justice did we conduct?'') of the proposal preamble (87 FR 73708) presents the full results of the demographic analysis. The analysis included an assessment of individual demographic groups of the populations living within 5 kilometers (km) and within 50 km of the existing facilities. We then compared the data from the analysis to the national average for each of the demographic groups. The results show that, for populations within 5 km of the 11 secondary lead smelters, the percent Hispanic or Latino population is higher than the national average (38 percent versus 19 percent). The percent of ''other and multiracial population'' and people living in linguistic isolation within the same geographic area are higher than the national average (12 percent versus 8 percent and 8 percent versus 5 percent, respectively). The percent of the population over 25 without a high school diploma is higher than the national average (19 percent versus 12 percent), while the percent of the population living below the poverty line is similar to the national average. The results of the analysis of populations within 50 km of the 11 secondary lead smelters are similar to the 5 km analysis.

The technical report, *Analysis of Demographic Factors for Populations Living Near Secondary Lead Smelting Source Category Operations,* which is available in the docket for this action (Docket ID No. EPA–HQ–OAR–2022–0481), presents the methodology and the results of the demographic analysis.

As indicated above, the locations of any new secondary lead smelting facilities that would be subject to NSPS subpart La are not known. Also, it is not known with any certainty which existing secondary lead smelters may be modified or reconstructed and subject to the NSPS subpart La. Thus, we are limited in our ability to estimate the potential EJ impacts of this rule. However, we anticipate the changes to the NSPS will generally minimize or reduce future emissions in surrounding communities of new, modified, or reconstructed facilities, including those communities with higher percentages of people of color. Furthermore, the EPA expects that the NSPS subpart La, will ensure compliance with the PM emissions and opacity limits at all times (including periods of SSM) via initial and periodic emissions testing. NSPS subpart La also codifies standards of performance reflecting improvements in PM control technologies that have occurred in the industry since promulgation of the current NSPS subpart L. Therefore, effects of emissions on populations in proximity to any future affected sources, including in communities potentially overburdened by pollution, which are often people of color, low-income, and Indigenous communities, will be minimized due to compliance with the standards of performance being finalized in 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 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)

The information collection activities in this final rule have been submitted for approval to OMB under the PRA. The updated Information Collection Request (ICR) document that the EPA prepared for NSPS subpart L has been assigned EPA ICR number 1128.13, and the new ICR prepared for the final NSPS subpart La has been assigned EPA ICR number 2729.01. You can find copies of the ICRs in the docket for this rule, and they are briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

The EPA is finalizing amendments to the existing NSPS (40 CFR part 60, subpart L) that:

- Require periodic testing for PM emissions.
- Incorporate monitoring, recordkeeping, and reporting requirements that are consistent with NESHAP subpart X.
- Require electronic reporting of performance test results.

A summary of the ICR for NSPS subpart L follows:

Respondents/affected entities: Secondary lead smelting facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart L).

Estimated number of respondents: Nine existing facilities subject to 40 CFR part 60, subpart L.

Frequency of response: Annually.

Total estimated burden: The annual recordkeeping and reporting burden for facilities to comply with all the requirements in the NSPS is estimated to be 228 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 NSPS is estimated to be $27,000 (per year).

The EPA is also finalizing a new subpart (40 CFR part 60, subpart La) for new, modified, or reconstructed facilities that commenced construction, reconstruction, or modification after December 1, 2022, that:

- Includes definitions for ''blast furnace,'' ''lead,'' ''reverberatory furnace,'' and ''secondary lead smelter'' that are the same as NSPS subpart L.
- Includes a definition for ''process fugitive emissions source'' to be consistent with the definition used in NESHAP subpart X.
- Establishes a tighter PM limit (10 mg/dscm) for blast and reverberatory furnaces.
- Establishes a new PM limit (4.9 mg/dscm) for process fugitive emissions sources.
- Establishes a tighter opacity limit (5 percent) for blast, reverberatory, and process fugitive emissions sources.
- Removes the exemptions for periods of SSM.
- Requires initial and periodic testing for PM emissions and opacity.
- Incorporates monitoring, recordkeeping, and reporting requirements that are consistent with the NESHAP (40 CFR part 63, subpart X).
- Requires electronic reporting of performance test results.

A summary of the ICR for NSPS subpart La follows:

Respondents/affected entities: Secondary lead smelting facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart La).

Estimated number of respondents: Three facilities (two reconstructed and one new source) in the next 3 years.

Frequency of response: Annually.

Total estimated burden: The annual recordkeeping and reporting burden for facilities to comply with all the requirements in the NSPS is estimated to be 127 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 NSPS is estimated to be $14,000 (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 (SISNOSE) under the RFA.

This action will not impose any significant requirements on small entities. Details of the analysis in support of this determination are presented in the memorandum titled, *Economic Impact Analysis and Small Business Screening Assessment for Final Revisions and Amendments to the New Source Performance Standards for Secondary Lead Smelters,* which is available in the docket for this action (Docket ID No. EPA–HQ–OAR–2022–0481).

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, and there are no nationwide annualized costs of this final rule for affected industrial sources in 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 (65 FR 67249; November 9, 2000). 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, as specified in Executive Order 13175. This final rule imposes requirements on owners and operators of secondary lead smelting facilities and not tribal governments. The EPA does not know of any secondary lead smelting facilities owned or operated by Indian tribal governments. 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.

The EPA does not believe there are disproportionate risks to children because the new NSPS subpart La lowers PM emissions and opacity from new, modified, or reconstructed secondary lead smelters compared to the current NSPS, which will benefit children's health. Additionally, the periodic PM emissions and opacity testing requirements of NSPS subparts La and L, and the updated monitoring, recordkeeping, and reporting requirements, improve compliance with emission limits, which also benefits children's health.

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 action involves technical standards. The EPA is requiring use of EPA Method 5 (Determination of Particulate Matter emissions from Stationary Sources) to measure filterable PM and EPA Method 9 (Visual Determination of the Opacity of Emissions from Stationary Sources) to determine visible emissions from blast and reverberatory process vents and process fugitive emissions. Therefore, the EPA conducted searches for the Secondary Lead Smelting NSPS through the Enhanced National Standards Systems Network Database managed by the American National Standards Institute (ANSI). We also contacted voluntary consensus standards (VCS) organizations and accessed and searched their databases.

We conducted searches for EPA Methods 1, 1A, 2, 2A, 2B, 2C, 2D, 2F, 2G, 2H, 3, 3A, 3C, 4, 5, 9, 12, 22, and 29 of 40 CFR part 60, appendix A. 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 reference method, the EPA 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 reference methods. The EPA may reconsider determinations of impracticality when additional information is available for a particular VCS. No applicable VCS were identified for EPA Methods 1, 1A, 2, 2A, 2B, 2C, 2D, 2F, 2G, 2H, 3, 3A, 3C, 4, 5, 12, 22, or 29.

In this final action, the EPA incorporates by reference the VCS ASTM D7520–16, ''Standard Test Method for Determining the Opacity of a Plume in the Outdoor Ambient Atmosphere approved April 1, 2016'' which 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. This method is 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 DCOT method is an acceptable alternative to EPA Method 9 with the following caveats:

• 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).

- You must also have SOP 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.
- You must follow the recordkeeping procedures outlined in 40 CFR 63.10(b)(1) for the DCOT certification, compliance report, data sheets, and all raw unaltered JPEG files used for opacity and certification determination.
- You 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.
- 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. This method describes procedures to determine the opacity of a plume, using digital imagery and associated hardware and software, where opacity is caused by PM emitted from a stationary point source in the outdoor ambient environment. The opacity of emissions is determined by the application of a DCOT that consists of a digital still camera, analysis software, and the output function's content to obtain and interpret digital images to determine and report plume opacity.

The ASTM D7520–16 document is 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) 8329555; *service@astm.org.*

The EPA is finalizing the use of the guidance document, EPA–454/R–98–015, Office of Air Quality Planning and Standards (OAQPS Fabric Filter Bag Leak Detection Guidance, September 1997. This document provides guidance on the use of triboelectric monitors as fabric filter bag leak detectors. The document includes fabric filter and monitoring system descriptions; guidance on monitor selection, installation, setup, adjustment, and operation; and quality assurance procedures. Several types of instruments are available to monitor changes in particulate emission rates for the purpose of detecting fabric filter bag leaks or similar failures. The principles of operation of these instruments include electrical charge transfer and light scattering. The document is available at *https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=2000D5T6.PDF.*

Additional information for the VCS search and determinations can be found in the docket for this final action (Docket ID No. EPA–HQ–OAR–2022–0481).

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

Executive Order 14096 (88 FR 25251, Apr. 26, 2023) directs federal agencies to advance the goal of environmental justice for all. This action builds upon and supplements the efforts of Executive Order 12898 (59 FR 7629, February 16, 1994) to address environmental justice.

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 locations of future new, modified, and reconstructed secondary lead smelters are not known with any certainty. Therefore, we evaluated the populations living near existing secondary lead smelters as a proxy for the characteristics of the demographics in areas where a new, modified, or reconstructed source might locate in the future. The result of the analysis shows that the percent Hispanic or Latino population, ''other and multiracial population'' and people living in linguistic isolation within the same geographic area, over 25 without a high school diploma are higher than the national average.

The EPA believes that this action is likely to reduce existing potential disproportionate and adverse effects on communities with environmental justice concerns. We anticipate the changes to the NSPS will generally minimize or reduce future emissions in these communities that are in proximity to new, modified, or reconstructed facilities. Specifically, the EPA expects that the Standards of Performance for Secondary Lead Smelters Constructed after December 1, 2022, will ensure compliance with the PM and opacity limits at all times (including periods of SSM) via initial and periodic emissions testing and parametric monitoring of control devices. Subpart La also codifies improvements in PM control technologies that have occurred in the industry since promulgation of the current NSPS subpart L. Therefore, effects of emissions on populations in proximity to any future affected sources, including in communities with environmental justice concerns, will be minimized due to compliance with the standards of performance being finalized in this action.

The information supporting this Executive Order review is contained in a technical report, *Analysis of Demographic Factors for Populations Living Near Secondary Lead Smelting Source Category Operations,* available in the docket for this action (Docket ID No. EPA–HQ–OAR–2022–0481), and in section IV.F. of the proposed rule's preamble (87 FR 73708), as well as summarized 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 60

Environmental protection, Administrative practice and procedures, Air pollution control, Incorporation by reference, Reporting and recordkeeping requirements.

Michael S. Regan,
Administrator.

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

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

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

Subpart A—General Provisions

■ 2. Amend § 60.17 by revising paragraphs (h)(206) and (j)(2) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(h) * * *

(206) 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 §§ 60.123(c)(6); 60.123(c)(6)(i); 60.123(c)(6)(ii); 60.123(c)(6)(v); 60.123a(c)(6)(ii); 60.123a(c)(6)(ii)(A); 60.123a(c)(6)(ii)(B); 60.123a(c)(6)(ii)(E); 60.271(k); 60.272(a) and (b); 60.273(c) and (d); 60.274(h); 60.275(e); 60.276(c); 60.271a; 60.272a(a) and (b); 60.273a(c) and (d); 60.274a(h); 60.275a(e); 60.276a(f); 60.271b; 60.272b(a) and (b); 60.273b(c) and (d); 60.274b(h); 60.275b(e); 60.276b(f); 60.374a(d).

* * * * *

(j) * * *

(2) EPA–454/R–98–015, Office of Air Quality Planning and Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance, September 1997, *https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=2000D5T6.PDF;* IBR approved for §§ 60.124(f); 60.124a(f); 60.273(e); 60.273a(e); 60.273b(e); 60.373a(b); 60.2145(r); 60.2710(r); 60.4905(b); 60.5225(b).

* * * * *

Subpart L—Standards of Performance for Secondary Lead Smelters for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and On or Before December 1, 2022

■ 3. Revise the heading for subpart L to part 60 to read as set forth above.

■ 4. Amend § 60.120 by revising paragraph (b) to read as follows:

§ 60.120 Applicability and designation of affected facility.

* * * * *

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, and on or before December 1, 2022, is subject to the requirements of this subpart.

■ 5. Amend § 60.122 by revising paragraph (a)(1) to read as follows:

§ 60.122 Standard for particulate matter.

(a) * * *

(1) Contain particulate matter (PM) in excess of 50 milligrams per dry standard cubic meter, mg/dscm (0.022 grains per dry standard cubic feet, gr/dscf).

* * * * *

■ 6. Revise § 60.123 to read as follows:

§ 60.123 Test methods and procedures.

(a) *Initial performance tests.* The owner or operator shall conduct performance tests to demonstrate initial compliance with the PM emission and opacity standards specified in § 60.122.

(b) *Periodic performance tests.* After November 20, 2023, the owner or operator shall conduct periodic performance tests to demonstrate compliance with the PM emissions standards specified in § 60.122(a). The owner or operator shall conduct the first periodic test by no later than July 31, 2024. The owner or operator shall conduct subsequent periodic tests according to the schedule specified in paragraph (b)(1) or (2) of this section.

(1) Conduct performance tests no later than 12 months following the previous compliance test.

(2) Conduct performance tests no later than 24 months following the previous compliance test if the previous compliance test measured PM emissions of 25 mg/dscm or less and the owner or operator has obtained approval from the Administrator for a written request to extend the period of the periodic performance test. The extension request will be deemed automatically approved if the owner or operator submits the results of a PM performance test of 25 mg/dscm or less, the owner or operator submits the request for the extension within 4 months after the subject compliance test, and the Administrator does not provide a response to such request within 6 months of submission.

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

(1) EPA Method 1 at appendix A–1 to this part to select sampling port locations and the number of traverse points.

(2) EPA Method 2 at appendix A–1 to this part or EPA Method 5D at appendix A–3 to this part, section 8.3 for positive fabric filters, to measure the volumetric flow rate of the gas stream.

(3) EPA Method 3, 3A, or 3B at 40 CFR part 60, appendix A–2 to determine the dry molecular weight of the stack gas and concentrations of carbon dioxide and oxygen in the sample gas.

(4) EPA Method 4 at appendix A–3 to this part to determine the moisture content of the gas stream.

(5) EPA Method 5 or 5D at appendix A–3 to this part to measure PM concentrations. The EPA Method 5 tests shall be conducted during representative periods of furnace operation, including charging and tapping, and the sampling time and sample volume for each test run shall be at least 60 minutes and 0.90 dscm (31.8 dscf), respectively. As an alternative to using EPA Method 5, owners or operators may measure PM emissions by the following methods:

(i) EPA Method 12 at appendix A–5 to this part (see section 16.1 of Method 12) to measure PM and inorganic lead concentrations.

(ii) EPA Method 29 at appendix A–8 to this part to measure metal (lead) concentrations and PM (see section 1.2 of Method 29).

(6) EPA Method 9 at appendix A–4 to this part and the procedures specified in § 60.11 for determining opacity. ASTM D7520–16 (incorporated by reference at § 60.17) is an acceptable alternative to EPA Method 9 with the specified conditions in paragraphs (c)(6)(i) through (v) of this section.

(*i*) During the digital camera opacity technique (DCOT) certification procedure outlined in section 9.2 of ASTM D7520–16 (incorporated by reference at § 60.17), the owner or operator or the DCOT vendor shall 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 shall also have standard operating procedures (SOPs) 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 at § 60.17). Records shall be maintained in a form suitable and readily available for expeditious review.

(iii) The owner or operator shall 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 shall 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 any one reading and the average error shall not exceed 7.5 percent opacity.

(v) 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 (incorporated by reference at § 60.17) and this section is on the owner or operator, DCOT operator, and DCOT vendor.

■ 7. Add §§ 60.124 and 60.125 to subpart L to read as follows:

§ 60.124 Monitoring requirements.

(a) The owner shall comply with the applicable monitoring requirements specified in the NSPS General provision § 60.13.

(b) The owner shall prepare, and at all times operate according to, a SOP manual that describes in detail procedures for inspection, maintenance, and bag leak detection and corrective action plans for all baghouses (fabric filters or cartridge filters) used to reduce PM and opacity emissions from any affected source subject to the emissions standards in § 60.122.

(c) The owner shall submit the SOP manual for the baghouses (fabric filters or cartridge collectors) described in paragraph (b) of this section to the Administrator or delegated authority for review and approval.

(d) The procedures specified in the SOP manual for inspections and routine maintenance shall, at a minimum, include the requirements of paragraphs (d)(1) through (9) of this section.

(1) Daily monitoring of the pressure drop across each baghouse cell.

(2) Weekly confirmation that dust is being removed from hoppers through visual inspection, or equivalent means of ensuring the proper functioning of removal mechanisms.

(3) Daily check of compressed air supply for pulse-jet baghouses.

(4) An appropriate methodology for monitoring cleaning cycles to ensure proper operation.

(5) Monthly check of bag cleaning mechanisms for proper functioning through visual inspection or equivalent means.

(6) Monthly check of bag tension on reverse air and shaker-type baghouses. Such checks are not required for shaker-type baghouses using self-tensioning (spring loaded) devices.

(7) Quarterly confirmation of the physical integrity of the baghouse through visual inspection of the baghouse interior for air leaks.

(8) Quarterly inspection of fans for wear, material buildup, and corrosion through visual inspection, vibration detectors, or equivalent means.

(9) Continuous operation of a bag leak detection system.

(e) The procedures specified in the SOP manual for baghouse maintenance shall include, at a minimum, a preventative maintenance schedule that is consistent with the baghouse manufacturer's instructions for routine and long-term maintenance.

(f) The bag leak detection system required by paragraph (d)(9) of this section, shall meet the specification and requirements of paragraphs (f)(1) through (8) of this section.

(1) The bag leak detection system shall be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 50.0 mg/dscm (0.022 gr/dscf) or less.

(2) The bag leak detection system sensor shall provide output of relative PM loadings.

(3) The bag leak detection system shall be equipped with an alarm system that will alarm when an increase in relative particulate loadings is detected over a preset level.

(4) The owner shall install and operate the bag leak detection system in a manner consistent with the guidance provided in EPA–454/R–98–015, Office of Air quality Planning and Standards (OAQPS) Fabric Filter Bag Leak Detection Guidance, (incorporated by reference, see § 60.17) or the manufacturer's written specifications and recommendations for installation, operation, and adjustment of the system.

(5) The initial adjustment of the system shall, at a minimum, consist of establishing the baseline output by adjusting the sensitivity (range) and the averaging period of the device, and establishing the alarm set points and the alarm delay time.

(6) Following initial adjustment, the owner shall not adjust the sensitivity or range, averaging period, alarm set points, or alarm delay time, except as detailed in the approved SOP manual required under paragraph (b) of this section. The owner cannot increase the sensitivity by more than 100 percent or decrease the sensitivity by more than 50 percent over a 365-day period unless such adjustment follows a complete baghouse inspection that demonstrates that the baghouse is in good operating condition.

(7) For negative pressure, induced air baghouses, and positive pressure baghouses that are discharged to the atmosphere through a stack, the owner shall install the bag leak detector downstream of the baghouse and upstream of any wet acid gas scrubber.

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

(g) The owner shall include in the SOP manual required by paragraph (b) of this section a corrective action plan that specifies the procedures to be followed in the case of a bag leak detection system alarm. The corrective action plan shall include, at a minimum, the procedures used to determine and record the time and cause of the alarm as well as the corrective actions taken to minimize emissions as specified in paragraphs (g)(1) and (2) of this section.

(1) The procedures used to determine the cause of the alarm shall be initiated within 30 minutes of the alarm.

(2) The cause of the alarm shall be alleviated by taking the necessary corrective action(s) that may include, but not be limited to, those listed in paragraphs (g)(2)(i) through (vi) of this section.

(i) Inspecting the baghouse for air leaks, torn or broken filter elements, or any other malfunction 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 repairing the bag leak detection system.

(vi) Shutting down the process producing the PM emissions.

(h) Baghouses equipped with high-efficiency particulate air (HEPA) filters as a secondary filter used to control emissions from any source subject to the PM and opacity emission standards in § 60.122 are exempt from the requirement to be equipped with a bag leak detection system. The owner or operator shall monitor and record the pressure drop across each HEPA filter system daily. If the pressure drop is outside the limit(s) specified by the filter manufacturer, the owner or operator shall take appropriate corrective measures, which may include but not be limited to those given in paragraphs (h)(1) through (4) of this section.

(1) Inspecting the filter and filter housing for air leaks and torn or broken filters.

(2) Replacing defective filter media, or otherwise repairing the control device.

(3) Sealing off a defective control device by routing air to other control devices

(4) Shutting down the process producing the particulate emissions.

(i) Baghouses followed by a wet electrostatic precipitator (WESP) used as a secondary control device for any source subject to the PM and opacity emission standards in § 60.122 are exempt from the requirement to be equipped with a bag leak detection system.

(j) If a wet scrubber is used to demonstrate continuous compliance with the PM emissions standards for blast and reverberatory furnaces specified in § 60.122(a), the owner or operator shall monitor and record the pressure drop and water flow rate of the wet scrubber during the initial performance or periodic compliance test conducted to demonstrate compliance with the PM emissions limit under § 60.122(a). Thereafter, the owner or operator shall monitor and record the pressure drop and water flow rate values at least once every hour and maintain the pressure drop and water flow rate at levels no lower than 30 percent below the pressure drop and water flow rate measured during the initial performance or compliance test.

(k) During the initial performance test required by § 60.123(a), or any periodic performance test required by § 60.123(b), the owner or operator shall establish the value or range of values of the monitoring parameter(s) for each control device used to comply with the PM and opacity emission standards specified in § 60.122.

(l) If an affected source is subject to the monitoring requirements specified in 40 CFR part 63, subpart X (National Emissions Standards for Hazardous Air Pollutants from Secondary Lead Smelting) and those requirements are as stringent or more stringent than the monitoring requirements specified in paragraphs (a) through (j) of this section, compliance with the monitoring requirements specified in 40 CFR part 63, subpart X also demonstrates compliance with the monitoring requirements specified in paragraphs (a) through (k) of this section.

§ 60.125 Notification, recordkeeping, and reporting requirements.

(a) The owner or operator shall comply with the applicable notification and recordkeeping requirements specified in § 60.7 and the reporting requirements specified in the NSPS General Provisions § 60.19.

(1) Records shall be maintained in a form suitable and readily available for expeditious review, according to § 60.7(f). However, electronic recordkeeping and reporting may be used if suitable for the specific case (*e.g.,* by electronic media such as Excel spreadsheet, on CD or hard copy), and when required by this subpart.

(2) Records shall be kept on site for at least 2 years after the date of occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7(f).

(b) The SOP manual required in § 60.124(b) shall be submitted to the Administrator in electronic format for review and approval of the initial submittal and whenever an update is made to the procedure.

(c) The owner or operator shall maintain for a period of 2 years, records of the information listed in paragraphs (c)(1) through (10) of this section.

(1) Electronic records of the bag leak detection system output.

(2) An identification of the date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the corrective actions taken, and the date and time the cause of the alarm was corrected.

(3) All records of inspections and maintenance activities required under § 60.124(d) as part of the practices described in the SOP manual for baghouses required under § 60.124(b).

(4) Electronic records of the pressure drop and water flow rate values for wet scrubbers used to control PM emissions from blast or reverberatory furnaces as required in § 60.124(j).

(5) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control equipment and monitoring equipment.

(6) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 60.11(d), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(7) Records of all alarms from the bag leak detection system specified in § 60.124(d)(9).

(8) Records maintained as part of the practices described in the SOP manual for baghouses required under § 60.124(b), including an explanation of the periods when the procedures were not followed, and the corrective actions taken.

(9) Record of the periods when the pressure drop and water flow rate of wet scrubbers used to control process fugitive sources dropped below the levels established in § 60.124(j), and an explanation of the corrective actions taken.

(10) Records of the rationale for the control device monitoring parameter value(s), established as specified in § 60.124(k), monitoring frequency, and averaging time. Include all 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 applicable emission standard.

(d) In addition to the reporting requirements specified in § 60.7 and § 60.19, the owner or operator shall submit the results of the initial and periodic performance tests within 60 days after the date of completing each performance test required by this subpart, following the procedures specified in paragraphs (d)(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 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 shall be submitted in a file format generated using the EPA's ERT. Alternatively, the owner or operator 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 shall 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) Confidential business information (CBI).

(i) The EPA will make all the information submitted through CEDRI available to the public without further notice to the owner or operator. Do not use CEDRI to submit information that the owner or operator claims as CBI. Although we do not expect persons to assert a claim of CBI, if the owner or operator wishes to assert a CBI claim for some of the information submitted under paragraph (a)(1) or (2) of this section, the owner or operator shall submit a complete file, including information claimed to be CBI, to the EPA.

(ii) The file shall 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 the owner or operator claims 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 shall 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 the owner or operator does not have a file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(v) If the owner or operator cannot transmit the file electronically, the owner or operator 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.

(vi) All CBI claims shall 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) The owner or operator shall submit the same file submitted to the CBI office with the CBI omitted to the EPA through CEDRI via the EPA's CDX as described in paragraphs (d)(1) and (2) of this section.

(e) Claims of EPA system outage. If the owner or operator is required to electronically submit a report through CEDRI in the EPA's CDX, the owner or operator 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, the owner or operator shall meet the requirements outlined in paragraphs (e)(1) through (7) of this section.

(1) The owner or operator shall 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 shall 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) The owner or operator shall submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) The owner or operator shall 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 the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the owner or operator 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 shall be submitted electronically as soon as possible after the outage is resolved.

(f) *Claims of force majeure.* If the owner or operator is required to electronically submit a report through CEDRI in the EPA's CDX, the owner or operator may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure,* the owner or operator shall meet the requirements outlined in paragraphs (f)(1) through (5) of this section.

(1) The owner or operator 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 the owner or operator 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) The owner or operator shall submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) The owner or operator shall 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 the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the owner or operator 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 shall occur as soon as possible after the *force majeure* event occurs.

■ 8. Add subpart La consisting of §§ 60.120a through 60.125a to part 60 to read as follows:

Subpart La—Standards of Performance for Secondary Lead Smelters for Which Construction, Reconstruction, or Modification Commenced After December 1, 2022

Subpart La—Standards of Performance for Secondary Lead Smelters for Which Construction, Reconstruction, or Modification Commenced After December 1, 2022

§ 60.120a Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in secondary lead smelters: Process fugitive emissions sources, blast (cupola) furnaces, and reverberatory furnaces.

(b) Any facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 20, 2023, is subject to the requirements of this subpart.

§ 60.121a Definitions.

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

Blast furnace means any furnace used to recover metal from slag.

Lead means elemental lead or alloys in which the predominant component is lead.

Process fugitive emissions source means a source of particulate matter (PM) emissions at a secondary lead smelter that is associated with lead smelting or refining including, but not limited to, smelting furnace charging points; smelting furnace lead and slag taps; pot and refining furnaces; and casting kettles.

Reverberatory furnace includes the following types of reverberatory furnaces: stationary, rotating, rocking, and tilting.

Secondary lead smelter means any facility producing lead from a lead-bearing scrap material by smelting to the metallic form.

§ 60.122a Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from a blast (cupola) or reverberatory furnace any gases which:

(1) Contain PM in excess of 10 milligrams per dry standard cubic meter, mg/dscm (0.0044 grains per dry standard cubic feet, gr/dscf).

(2) Exhibit opacity greater than 5 percent.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any process fugitive emissions source any gases which:

(1) Contain PM in excess of 4.9 mg/dscm (0.0021 grains per dry standard cubic feet, gr/dscf).

(2) Exhibit opacity greater than 5 percent.

(c) The PM and opacity emissions standards specified in paragraphs (a) and (b) of this section apply at all times, including periods of startup, shutdown, and malfunction.

§ 60.123a Test methods and procedures.

(a) *Initial performance tests.* The owner or operator shall conduct performance tests to demonstrate initial compliance with the PM and opacity emission standards specified in § 60.122a.

(b) *Periodic performance tests.* Following the initial compliance demonstration required by paragraph (a) of this section, the owner or operator shall conduct periodic performance tests to demonstrate compliance with the PM and opacity emissions standards specified in § 60.122a according to the schedule specified in paragraph (b)(1) or (2) of this section.

(1) Conduct performance tests no later than 12 months following the previous compliance test.

(2) Conduct performance tests up to 24 calendar months following the previous compliance test if the previous compliance test measured PM emissions equal to or less than the concentrations specified in paragraphs (b)(2)(i) and (ii) of this section and the owner or operator has obtained approval from the Administrator for a written request to extend the period of the periodic performance test. The extension request will be deemed automatically approved if the owner or operator submits the results of a PM performance test equal to or less than the applicable concentrations specified in paragraphs (b)(2)(i) and (ii) of this section, the owner or operator submits the request for the extension within 4 months after the subject compliance test, and the Administrator does not provide a response to such request within 6 months of submission.

(i) 5 mg/dscm for blast and reverberatory furnaces.

(ii) 2.4 mg/dscm for process fugitive emissions sources.

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

(1) EPA Method 1 at appendix A–1 to this part for selecting sampling port locations and the number of traverse points.

(2) EPA Method 2 at appendix A–1 to this part at appendix A–1 to this part or EPA Method 5D at appendix A–3 to this part, section 8.3 for positive fabric filters, to measure the volumetric flow rate of the gas stream.

(3) EPA Method 3, 3A, 3B, or 3C at appendix A–1 to this part to determine the dry molecular weight of the stack gas and the concentrations of carbon dioxide and oxygen in the sample gas.

(4) EPA Method 4 at appendix A–3 to this part to determine the moisture content of the gas stream.

(5) EPA Method 5 or 5D at appendix A–3 to this part for measuring PM concentrations. The EPA Method 5 or 5D tests shall be conducted during representative periods of furnace operation, including charging and tapping, and the sampling time and sample volume for each test run shall be at least 60 minutes and 0.90 dscm (31.8 dscf), respectively. As an alternative to using EPA Method 5, owners or operators may measure PM emissions by the following methods:

(i) EPA Method 12 at appendix A–5 to this part (see section 16.1 of Method 12) to measure inorganic lead concentrations and PM.

(ii) EPA Method 29 at appendix A–8 to this part to measure metal (lead) concentrations and PM (see section 1.2 of Method 29).

(6) EPA Method 9 at appendix A–4 to this part and the procedures specified in § 60.11 for determining opacity. Owners or operators may use the following methods as alternatives to EPA Method 9 as applicable and appropriate:

(i) EPA Method 22 (Visual Determination of Fugitive Emissions) at appendix A–7 to this part for determining no visible emissions.

(ii) ASTM D7520–16 (incorporated by reference at § 60.17) is an acceptable alternative with the specified conditions in paragraphs (c)(6)(ii)(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 (incorporated by reference at § 60.17), the owner or operator or the DCOT vendor shall 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) The owner or operator shall also have standard operating procedures (SOPs) 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 at § 60.17).

(C) The owner or operator shall 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.

(D) The owner or operator or the DCOT vendor shall 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 *any one* reading and the average error shall not exceed 7.5 percent 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 (incorporated by reference at § 60.17) and this section is on the owner or operator, DCOT operator, and DCOT vendor.

§ 60.124a Monitoring requirements.

(a) The owner shall comply with the applicable monitoring requirements specified in § 60.13.

(b) The owner shall prepare, and at all times operate according to, an SOP manual that describes in detail procedures for inspection, maintenance, and bag leak detection and corrective action plans for all baghouses (fabric filters or cartridge filters) used to reduce PM and opacity emissions from any affected source subject to the emissions standards in § 60.122a.

(c) The owner shall submit the SOP manual for the baghouses (fabric filters or cartridge collectors) described in paragraph (b) of this section to the Administrator or delegated authority for review and approval.

(d) The procedures specified in the SOP manual for inspections and routine maintenance shall, at a minimum, include the requirements of paragraphs (d)(1) through (9) of this section.

(1) Daily monitoring of the pressure drop across each baghouse cell.

(2) Weekly confirmation that dust is being removed from hoppers through visual inspection, or equivalent means of ensuring the proper functioning of removal mechanisms.

(3) Daily check of compressed air supply for pulse-jet baghouses.

(4) An appropriate methodology for monitoring cleaning cycles to ensure proper operation.

(5) Monthly check of bag cleaning mechanisms for proper functioning through visual inspection or equivalent means.

(6) Monthly check of bag tension on reverse air and shaker-type baghouses. Such checks are not required for shaker-type baghouses using self-tensioning (spring loaded) devices.

(7) Quarterly confirmation of the physical integrity of the baghouse through visual inspection of the baghouse interior for air leaks.

(8) Quarterly inspection of fans for wear, material buildup, and corrosion through visual inspection, vibration detectors, or equivalent means.

(9) Continuous operation of a bag leak detection system.

(e) The procedures specified in the SOP manual for baghouse maintenance shall include, at a minimum, a preventative maintenance schedule that is consistent with the baghouse manufacturer's instructions for routine and long-term maintenance.

(f) The bag leak detection system required by paragraph (d)(9) of this section, shall meet the specification and requirements of paragraphs (f)(1) through (8) of this section.

(1) The bag leak detection system shall be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 50.0 mg/dscm (0.022 gr/dscf) or less.

(2) The bag leak detection system sensor shall provide output of relative PM loadings.

(3) The bag leak detection system shall be equipped with an alarm system that will alarm when an increase in relative particulate loadings is detected over a preset level.

(4) The owner shall install and operate the bag leak detection system in a manner consistent with the guidance provided in EPA–454/R–98–015, Office of Air quality Planning and Standards (OAQPS) Fabric Filter Bag Leak Detection Guidance (incorporated by reference, see § 60.17) or the manufacturer's written specifications and recommendations for installation, operation, and adjustment of the system.

(5) The initial adjustment of the system shall, at a minimum, consist of establishing the baseline output by adjusting the sensitivity (range) and the averaging period of the device, and establishing the alarm set points and the alarm delay time.

(6) Following initial adjustment, the owner shall not adjust the sensitivity or range, averaging period, alarm set points, or alarm delay time, except as detailed in the approved SOP manual required under paragraph (b) of this section. The owner cannot increase the sensitivity by more than 100 percent or decrease the sensitivity by more than 50 percent over a 365-day period unless such adjustment follows a complete baghouse inspection that demonstrates that the baghouse is in good operating condition.

(7) For negative pressure, induced air baghouses, and positive pressure baghouses that are discharged to the atmosphere through a stack, the owner shall install the bag leak detector downstream of the baghouse and upstream of any wet acid gas scrubber.

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

(g) The owner shall include in the SOP manual required by paragraph (b) of this section a corrective action plan that specifies the procedures to be followed in the case of a bag leak detection system alarm. The corrective action plan shall include, at a minimum, the procedures used to determine and record the time and cause of the alarm as well as the corrective actions taken to minimize emissions as specified in paragraphs (g)(1) and (2) of this section.

(1) The procedures used to determine the cause of the alarm shall be initiated within 30 minutes of the alarm.

(2) The cause of the alarm shall be alleviated by taking the necessary corrective action(s) that may include, but not be limited to, those listed in paragraphs (g)(2)(i) through (vi) of this section.

(i) Inspecting the baghouse for air leaks, torn or broken filter elements, or any other malfunction 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 repairing the bag leak detection system.

(vi) Shutting down the process producing the PM emissions.

(h) Baghouses equipped with high-efficiency particulate air (HEPA) filters as a secondary filter used to control emissions from any source subject to the PM and opacity emission standards in § 60.122a are exempt from the requirement to be equipped with a bag leak detection system. The owner or operator shall monitor and record the pressure drop across each HEPA filter system daily. If the pressure drop is outside the limit(s) specified by the filter manufacturer, the owner or operator shall take appropriate corrective measures, which may include but not be limited to those given in paragraphs (h)(1) through (4) of this section.

(1) Inspecting the filter and filter housing for air leaks and torn or broken filters.

(2) Replacing defective filter media, or otherwise repairing the control device.

(3) Sealing off a defective control device by routing air to other control devices.

(4) Shutting down the process producing the particulate emissions.

(i) Baghouses followed by a wet electrostatic precipitator (WESP) used as a secondary control device for any source subject to the PM and opacity emission standards in § 60.122a are exempt from the requirement to be equipped with a bag leak detection system.

(j) If a wet scrubber is used to demonstrate continuous compliance with the PM emissions standards for blast and reverberatory furnaces specified in § 60.122a(a), the owner or operator shall monitor and record the pressure drop and water flow rate of the wet scrubber during the initial performance or annual compliance test conducted to demonstrate compliance with the PM emissions limit under § 60.122a(a). Thereafter, the owner or operator shall monitor and record the pressure drop and water flow rate values at least once every hour and maintain the pressure drop and water flow rate at levels no lower than 30 percent below the pressure drop and water flow rate measured during the initial performance or compliance test.

(k) During the initial performance test required by § 60.123a(a), or any periodic performance test required by § 60.123a(b), the owner or operator shall establish the value or range of values of the monitoring parameter(s) for each control device used to comply with the PM and opacity emission standards specified in § 60.122a.

(l) If an affected source is subject to the monitoring requirements specified in 40 CFR part 63, subpart X (National Emissions Standards for Hazardous Air Pollutants from Secondary Lead Smelting) and those requirements are as stringent or more stringent than the monitoring requirements specified in paragraphs (a) through (j) of this section compliance with 40 CFR part 63, subpart X also demonstrates compliance with the monitoring requirements specified in paragraphs (a) through (k) of this section.

§ 60.125a Notification, recordkeeping, and reporting requirements.

(a) The owner or operator shall comply with the applicable notification and recordkeeping requirements specified in § 60.7 and the reporting requirements specified in § 60.19.

(1) Records shall be maintained in a form suitable and readily available for expeditious review, according to § 60.7(f). However, electronic recordkeeping and reporting may be used if suitable for the specific case (*e.g.,* by electronic media such as Excel spreadsheet, on CD or hard copy), and when required by this subpart.

(2) Records shall be kept on site for at least 2 years after the date of occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7(f).

(b) The SOP manual required in § 60.124a(b) shall be submitted to the Administrator in electronic format for review and approval of the initial submittal and whenever an update is made to the procedure.

(c) The owner or operator shall maintain for a period of 2 years, records of the information listed in paragraphs (c)(1) through (10) of this section.

(1) Electronic records of the bag leak detection system output.

(2) An identification of the date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the corrective actions taken, and the date and time the cause of the alarm was corrected.

(3) All records of inspections and maintenance activities required under § 60.124a(d) as part of the practices described in the SOP manual for baghouses required under § 60.124a(b).

(4) Electronic records of the pressure drop and water flow rate values for wet scrubbers used to control PM emissions from blast or reverberatory furnaces as required in § 60.124a(j).

(5) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control equipment and monitoring equipment.

(6) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 60.11(d), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(7) Records of all alarms and corrective actions taken for the bag leak detection system specified in § 60.124a(d)(9).

(8) Records maintained as part of the practices described in the SOP manual for baghouses required under § 60.124a(b), including an explanation of the periods when the procedures were not followed, and the corrective actions taken.

(9) Record of the periods when the pressure drop and water flow rate of wet scrubbers used to control process fugitive sources dropped below the levels established in § 60.124a(j), and an explanation of the corrective actions taken.

(10) Records of the rationale for the control device monitoring parameter value(s), established as specified in § 60.124a(k), monitoring frequency, and averaging time. Include all 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 applicable emission standard.

(d) In addition to the reporting requirements specified in §§ 60.7 and 60.19, within 60 days after the date of completing each performance test required by this subpart, the owner or operator shall submit the results of the initial and periodic performance tests following the procedures as specified in paragraphs (d)(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 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 shall be submitted in a file format generated using the EPA's ERT. Alternatively, the owner or operator 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 shall 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) *Confidential business information (CBI).* (i) The EPA will make all the information submitted through CEDRI available to the public without further notice to the owner or operator. Do not use CEDRI to submit information the owner or operator claims as CBI. Although we do not expect persons to assert a claim of CBI, if the owner or operator wishes to assert a CBI claim for some of the information submitted under paragraph (a)(1) or (2) of this section, the owner or operator shall submit a complete file, including information claimed to be CBI, to the EPA.

(ii) The file shall 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 the owner or operator claims 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 shall 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 the owner or operator does not have a file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(v) If the owner or operator cannot transmit the file electronically, the owner or operator 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.

(vi) All CBI claims shall 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) The owner or operator shall submit the same file submitted to the CBI office with the CBI omitted to the EPA through CEDRI via the EPA's CDX as described in paragraphs (d)(1) and (2) of this section.

(e) If the owner or operator is required to electronically submit a report through CEDRI in the EPA's CDX, the owner or operator 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, the owner or operator shall meet the requirements outlined in paragraphs (e)(1) through (7) of this section.

(1) The owner or operator shall 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 shall 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) The owner or operator shall submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) The owner or operator shall 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 the owner or operator propose to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the owner or operator 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 shall be submitted electronically as soon as possible after the outage is resolved.

(f) If the owner or operator is required to electronically submit a report through CEDRI in the EPA's CDX, the owner or operator may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure,* the owner or operator shall meet the requirements outlined in paragraphs (f)(1) through (5) of this section.

(1) The owner or operator 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 the owner or operator 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) The owner or operator shall submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) The owner or operator shall 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 the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the owner or operator 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 shall occur as soon as possible after the *force majeure* event occurs.

[FR Doc. 2023–25275 Filed 11–17–23; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 52

[WC Docket Nos. 13–97, 07–243, 20–67; IB Docket No. 16–155; FCC 23–75; FR ID 183540]

Numbering Policies for Modern Communications

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: In this document, the Federal Communications Commission (Commission) adopts rules regarding direct access to numbers by providers of interconnected Voice over internet Protocol (VoIP) services. The Commission takes this action in furtherance of Congress' directive in the Pallone-Thune Telephone Robocall Abuse Criminal Enforcement and Deterrence (TRACED) Act to examine ways to reduce access to telephone numbers by potential perpetrators of illegal robocalls. These actions safeguard U.S. numbering resources and consumers, protect national security interests, promote public safety, and reduce opportunities for regulatory arbitrage.

DATES: Effective December 20, 2023, except for the amendments to 47 CFR 52.15(g)(3)(ii)(B) through (F), (I), (K), (L), and (N) and (g)(3)(x)(A) (amendatory instruction 3), which are delayed indefinitely. The amendments to 47 CFR

	2023–2027
(i) Feature	$.83
(ii) Feature (concert) (per half hour)	1.72
(iii) Background	.42

(5) The schedule of fees covers use for a period of three years following the first use. Succeeding use periods will require the following additional payment: Additional one-year period—25 percent of the initial three-year fee; second three-year period—50 percent of the initial three-year fee; each three-year fee thereafter—25 percent of the initial three-year fee; provided that a 100 percent additional payment prior to the expiration of the first three-year period will cover use during all subsequent use periods without limitation. Such succeeding uses which are subsequent to December 31, 2022, shall be subject to the schedule of royalty rates established in this section.

(6) For each use licensed under this section pursuant to paragraphs (b)(1)(i) and (b)(2) of this section for transmission via the internet, the royalty fees shall include a pro-rata share of $2,000 per calendar year, which share shall be determined by calculating the aggregate amount of royalty fees earned during that calendar year and dividing the sum by the amount of royalty fees earned for each use.

(c) *Payment of royalty rates.* The required royalty due under paragraphs (b)(1), (2), and (4) of this section shall be paid to each known copyright owner not later than July 31 of each calendar year for uses during the first six months of that calendar year and not later than January 31 for uses during the last six months of the preceding calendar year. The required royalty due under paragraph (b)(6) of this section for each calendar year of the statutory license term shall be paid to each known copyright owner not later than March 31 of each following year for PBS- or NPR-distributed uses via the internet during the preceding calendar year.

* * * * *

(e) *Filing of use reports with the Copyright Royalty Judges: deposit of cue sheets or summaries.* PBS and its stations, NPR, or other television public broadcasting entity shall deposit with the Copyright Royalty Judges via online filing in eCRB one electronic copy of their standard music cue sheets or summaries of same listing the recording pursuant to the schedule established in this section of the musical works of copyright owners. Such cue sheets or summaries shall be deposited not later than July 31 of each calendar year for recordings during the first six months of the calendar year and not later than January 31 of each calendar year for recordings during the second six months of the preceding calendar year. PBS and NPR shall maintain at their offices copies of all standard music cue sheets from which such music use reports are prepared. Such music cue sheets shall be furnished to the Copyright Royalty Judges upon their request and also shall be available during regular business hours at the offices of PBS or NPR for examination by a copyright owner who believes a musical composition of such owner has been recorded pursuant to the schedule.

§ 381.8 [Amended]

■ 7. In § 381.8:

■ a. In paragraph (b)(1) introductory text, add the words ''not otherwise licensed by the copyright owner'' at the end of the paragraph;

■ b. In paragraphs (b)(1)(i) and (ii), in the table header, remove the year ''2013–2017'' and add in its place the year ''2023–2027'';

■ c. In paragraph (d)(1), add the text '', upon request,'' after ''shall maintain and''; and

■ d. In paragraph (f)(1), remove the year ''2017'' and add in its place the year ''2027''.

■ 8. Revise § 381.10 to read as follows:

§ 381.10 Cost of living adjustment.

(a) On or before December 1, 2023, the Copyright Royalty Judges shall publish in the **Federal Register** a notice of the change in the cost of living as determined by the Consumer Price Index (all consumers, all items) during the period from the most recent Index published prior to December 1, 2022, to the most recent Index published prior to December 1, 2023. On or before each December 1 thereafter the Copyright Royalty Judges shall publish a notice of the change in the cost of living during the period from the most recent index published prior to the previous notice to the most recent Index published prior to December 1 of that year.

(b) On the same date of the notices published pursuant to paragraph (a) of this section, the Copyright Royalty Judges shall publish in the **Federal Register** a revised schedule of the rates for § 381.5(c)(3) and (4), the rates to be charged for compositions in the repertory of SESAC and GMR, which shall adjust the royalty amounts established in a dollar amount according to the greater of:

(1) The change in the cost of living determined as provided in paragraph (a) of this section; or

(2) One-and-a-half percent (1.5%).

(3) Such royalty rates shall be fixed at the nearest dollar.

(c) The adjusted schedule for the rates for § 381.5(c)(3) and (4) shall become effective thirty (30) days after publication in the **Federal Register**.

Dated: June 9, 2023.

David P. Shaw,

Chief Copyright Royalty Judge.

David R. Strickler,

Copyright Royalty Judge.

Steve Ruwe,

Copyright Royalty Judge.

Approved by:

Carla D. Hayden,

Librarian of Congress.

[FR Doc. 2023–13668 Filed 6–27–23; 8:45 am]

BILLING CODE 1410–72–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2020–0556; FRL–8335–06–OAR]

RIN 2060–AV35

Testing Provisions for Air Emission Sources; Correction

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; correcting amendment.

SUMMARY: The Environmental Protection Agency (EPA) is making a correcting amendment due to an error in a final rule that was published in the **Federal Register** on March 29, 2023, and became effective on May 30, 2023. The final rule corrected and updated regulations for source testing of emissions.

DATES: Effective June 28, 2023.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2020–0556. All documents in the docket are listed on the *www.regulations.gov* website. Although listed in the index, 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. Publicly available docket materials are available electronically through *www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Mrs. Lula H. Melton, Office of Air Quality Planning and Standards, Air Quality Assessment Division (E143–02), Environmental Protection Agency, Research Triangle Park, NC 27711;

telephone number: (919) 541–2910; fax number: (919) 541–0516; email address: *melton.lula@epa.gov.*

SUPPLEMENTARY INFORMATION: This correction does not change any final action taken by the EPA on March 29, 2023 (88 FR 18396); this action merely corrects language in section 1.1 of Performance Specification 16 of appendix B to part 60, which was inadvertently changed at 88 FR 18411 (March 29, 2023).

List of Subjects in 40 CFR Part 60

Environmental protection, Air pollution control, Incorporation by reference, Performance specifications, Test methods and procedures.

For the reasons stated in the preamble, EPA amends 40 CFR part 60 by making the following correcting amendment:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

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

■ 2. Amend appendix B to part 60 by revising the last sentence in section 1.1 of performance specification 16 to read as follows:

Appendix B to Part 60—Performance Specifications

* * * * *

Performance Specification 16—Specifications and Test Procedures for Predictive Emission Monitoring Systems in Stationary Sources

1.0 Scope and Application

1.1 * * * These specifications apply to PEMS that are installed under 40 CFR parts 60, 61, and 63 after April 24, 2009.

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Richard A. Wayland,

Director, Air Quality Assessment Division, Office of Air Quality Planning and Standards.

[FR Doc. 2023–13595 Filed 6–27–23; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 110 and 300

[EPA–HQ–OPA–2006–0090; FRL–4526–01–OLEM]

RIN 2050–AE87

National Oil and Hazardous Substances Pollution Contingency Plan; Product Schedule Listing and Authorization of Use Requirements

Correction

In rule document 2023–11904 beginning on page 38280 in the issue of Monday, June 12, 2023 make the following corrections:

Appendix C to Part 300

1. On page 38339, Equation 1 should read as follows:

$$theoretical\ concentration, \frac{mg}{mL} = \frac{mass\ of\ oil,\ g * 1000\ mg/g}{total\ mass,\ g/\rho_{solution}\ , g/mL} \qquad \text{(Equation 1)}$$

2. On page 38340, Equation 2 should read as follows:

$$\int_{340\lambda}^{400\lambda} f(x)dx \approx \frac{H}{2}\Sigma_{k=1}^{N}\left(f(x_{k+1}) + f(x_k)\right) \qquad \text{(Equation 2)}$$

3. On the same page, Equation 3 should read as follows:

$$Area = \frac{(Abs_{340} + Abs_{350}) * 10}{2} + \frac{(Abs_{350} + Abs_{360}) * 10}{2} + \cdots \frac{(Abs_{390} + Abs_{400}) * 10}{2} \qquad \text{(Equation 3)}$$

4. On page 38341, Equation 4 should read as follows:

$$RF = \frac{Theoretical\ \ Concentration\ \ , \frac{g}{mL}\,(Eq.1)}{area\ \ (Eq.3)} \qquad \text{(Equation 4)}$$

5. On the same page, Equation 5 should read as follows:

$$\%\ difference = \frac{|RF - \overline{RF}|}{\overline{RF}} * 100 \qquad \text{(Equation 5)}$$

6. On the same page, Equation 6 should read as follows: