Small Entity Compliance Guide

For

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

40 CFR Part 60, Subpart OOOOb

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40 CFR Part 60 Subpart OOOOb

U.S. Environmental Protection Agency

Office of Air Quality Planning and Standards

Research Triangle Park, NC

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Forward

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The statements in this document are intended solely to aid regulated entities in complying with the published national regulation "Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After December 6, 2022". The final rule was published on March 8, 2024, in Volume 8 of the Federal Register, (89 FR 16820) for Title 40 of the Code of Federal Regulations (40 CFR) Part 60, Subpart OOOOb – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after December 6, 2022.

The U.S. Environmental Protection Agency (EPA) may decide to revise this guide without public notice to reflect changes in the EPA's approach to implementing the rule's requirements or to clarify and update text. To determine whether the EPA has revised this guide and/or to obtain copies, contact Amy Hambrick at (919) 541-0964, hambrick.amy@epa.gov.

The full text of the rule is available online at:
https://www.federalregister.gov/documents/2024/03/08/2024-00366/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for

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1.0 Introduction to the Rule and this Compliance Guide

This document was published by the EPA as a compliance guide for small entities subject to the Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after December 6, 2022 (subpart OOOOb) as required by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA). Before you begin using the guide, keep in mind that the information in this guide was compiled and published in May 2024. The EPA is continually improving and updating its rules, policies, compliance programs, and outreach efforts. You can determine whether the EPA has revised or supplemented the information in this guide by checking the Oil and Natural Gas Sector program web page for the rule, compliance requirements, and technical and related information.

The final Oil and Natural Gas Sector New Source Performance Standards (NSPS) – called simply "the rule" in this document – was signed by the EPA Administrator on November 30, 2023, and published in the Federal Register on March 8, 2024. The rule's effective date is May 7, 2024, to allow 60 days for Congressional review after publication in the Federal Register. On this effective date, the rule's requirements become law. The information in this guide was compiled to assist those entities subject to the rule to better understand its requirements, and regulated entities are referred to the rule for details related to their compliance requirements.

1.1 What environmental/human health issue(s) does this rule address and why it is important?

The final requirements include standards for greenhouse gas (GHG) emissions (in the form of limitations on methane) and standards for volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions. Methane is a GHG that traps heat in the atmosphere, which leads to climate change. Recent scientific assessments confirm and strengthen the conclusion that GHG emissions endanger public health, now and in the future. Studies indicate that human health in the United States will be impacted by ''increased extreme weather events, wildfire, decreased air quality, threats to mental health, and illnesses transmitted by food, water, and disease-carriers such as mosquitoes and ticks.''[1] The most recent assessments now have greater confidence that climate change will influence production of pollen that exacerbates asthma and other allergic respiratory diseases such as allergic rhinitis, as well as effects on conjunctivitis and dermatitis.

[1] Luber, G., K. Knowlton, J. Balbus, H. Frumkin, M. Hayden, J. Hess, M. McGeehin, N. Sheats, L. Backer, C. B. Beard, K. L. Ebi, E. Maibach, R. S. Ostfeld, C. Wiedinmyer, E. Zielinski-Gutiérrez, and L. Ziska, 2014: Ch. 9: Human Health. Climate Change Impacts in the United States: The Third National Climate Assessment, J. M. Melillo, Terese (T.C.) Richmond, and G. W. Yohe, Eds., U.S. Global Change Research Program, 220-256. doi:10.7930/J0PN93H5.

Methane has an atmospheric life of about 12 years, and because of its potency as a GHG and its atmospheric life, reducing methane emissions is an important step that can be taken to achieve a near-term beneficial impact in mitigating global climate change. Methane is also a precursor to ground level ozone, a health-harmful air pollutant. Ozone is a short-lived climate forcer that contributes to global warming. Tropospheric, or ground level, ozone is also formed through reactions of VOC and nitrogen oxides (NOx) in the presence of sunlight. Ozone formation can be controlled to some extent through reductions in emissions of ozone precursor VOC and NOx. In remote areas, methane is a dominant precursor to tropospheric ozone formation.

1.2 What does the regulation require?

The Clean Air Act (CAA) requires the EPA to set NSPS for industrial categories that cause, or significantly contribute to, air pollution that may endanger public health or welfare. The rule establishes emission control standards for the oil and natural gas source category for GHGs (represented as methane), SO_2 and VOCs, which are significant pollutants with respect to climate change, national air pollution and human health issues. Oil and natural gas operations are one of the largest emitters of GHGs in the U.S. (when considering both methane emissions and combustion related GHG emissions at oil and gas facilities). The standards apply across a variety of emission sources in the oil and natural gas source category (i.e., production, processing, transmission, and storage). Although the oil and natural gas industry is primarily known to be rural, emissions are also found to occur in or near populated areas across the country, due to recent increases in development of wells and facilities.

This guide addresses the requirements of subpart OOOOb.[2] This rule applies to sources that are constructed, modified, or reconstructed after December 6, 2022, and reflects today's technology, referred to as best system of emission reduction (BSER), considering costs.

The rule achieves several objectives for oil and natural gas sector sources including addressing additional sources and applying updated emission control requirements that reflect the current BSER.

Table 1-1 summarizes these affected facilities (sources covered) by the rule and the final standards for GHGs and VOC emissions.

[2] A similar guide was prepared for 40 CFR Part 60, subpart OOOOa. This guide can be found on EPA's site at: **https://www.epa.gov/sites/default/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf**

Table 1-1. Summary of Final Subpart OOOOb Control Requirements

Affected Facility (Emission Source)	Final Subpart OOOOb Control Requirements
Well Completions: Subcategory 1 (non-wildcat and non-delineation wells).	➢ Reduced emissions completion (REC) in combination with a completion combustion device; venting in lieu of combustion where combustion would present demonstrable safety hazards. ➢ Initial flowback stage: Route to a storage vessel or completion vessel (frac tank, lined pit, or other vessel) and separator. ➢ Separation flowback stage: Route all salable gas from the separator to a flow line or collection system, re-inject the gas into the well or another well, use the gas as an onsite fuel source or use for another useful purpose that a purchased fuel or raw material would serve. If technically infeasible to route recovered gas as specified above, recovered gas must be combusted. All liquids must be routed to a storage vessel or well completion vessel, collection system, or be re-injected into the well or another well. ➢ The operator is required to have (and use) a separator onsite during the entire flowback period.
Well Completions: Subcategory 2 (exploratory, wildcat, and delineation wells and non-wildcat and non-delineation low pressure wells).	➢ The operator is not required to have a separator onsite. ➢ Either: (1) Route all flowback to a completion combustion device with a continuous pilot flame; or (2) 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 with a continuous pilot flame. ➢ For both options (1) and (2), combustion is not required 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.

Affected Facility (Emission Source)	Final Subpart OOOOb Control Requirements
Well Liquids Unloading.	Perform best management practices to minimize or eliminate methane and VOC emissions to the maximum extent possible from liquids unloading events that vent emissions to the atmosphere.
Well Liquids Unloading (Alternative)	Capture and route emissions from liquids unloading event to a control device that achieves a 95 percent reduction of methane and VOC emissions.
New Wells with Associated Gas that commenced construction after May 7, 2026.	Route associated gas to a sales line; or, the gas can be used for another useful purpose that a purchased fuel, chemical feedstock, or raw material would serve, or recovered from the separator and reinjected into the well or injected into another well.
New wells with Associated Gas that commenced construction between May 7, 2024, and May 7, 2026.	Route associated gas to a sales line; or, the gas can be used for another useful purpose that a purchased fuel, chemical feedstock, or raw material would serve, or recovered from the separator and reinjected into the well or injected into another well. If demonstrated, and documented annually, that routing to a sales line and the alternatives are not technically feasible, the associated gas can be routed to a flare or other control device that achieves at least 95 percent reduction in GHG (methane) and VOC emissions. A second infeasibility determination may not extend beyond 24 months from effective date.

Affected Facility (Emission Source)	Final Subpart OOOOb Control Requirements
New Wells with Associated Gas that Commenced Construction after December 6, 2022, and before May 7, 2024.	Route associated gas to a sales line; or, the gas can be used for another useful purpose that a purchased fuel, chemical feedstock, or raw material would serve, or recovered from the separator and reinjected into the well or injected into another well. If demonstrated, and documented annually, that routing to a sales line and the alternatives are not technically feasible, the associated gas can be routed to a flare or other control device that achieves at least 95 percent reduction in GHG (methane) and VOC emissions.
Wells with Associated Gas Reconstructed or Modified after December 6, 2022.	Route associated gas to a sales line; or, the gas can be used for another useful purpose that a purchased fuel, chemical feedstock, or raw material would serve, or recovered from the separator and reinjected into the well or injected into another well. If demonstrated, and documented annually, that routing to a sales line and the alternatives are not technically feasible, the associated gas can be routed to a flare or other control device that achieves at least 95 percent reduction in GHG (methane) and VOC emissions.
Wet Seal Centrifugal Compressors (except for those located at well sites).	Capture and route emissions from the wet seal fluid degassing system to a control device that achieves a 95 percent reduction of methane and VOC emissions.

Affected Facility (Emission Source)	Final Subpart OOOOb Control Requirements
Wet Seal Centrifugal Compressors (except for those located at well sites): Self-contained centrifugal compressors (including those compressors equipped with a mechanical seal).	(Alternative) Monitoring and repair to maintain volumetric flow rate at or below 3 scfm per compressor seal.
Wet Seal Centrifugal Compressors (except for those located at well sites): Alaska North Slope centrifugal compressors equipped with a seal oil recovery system.	(Alternative) Monitoring and repair to maintain volumetric flow rate at or below 9 scfm per seal.
Dry Seal Centrifugal Compressors (except for those located at well sites).	Monitoring and repair to maintain volumetric flow rate at or below 10 scfm per seal.

Affected Facility (Emission Source)	Final Subpart OOOOb Control Requirements
Reciprocating compressors (except for those located at well sites).	Monitoring and repair or replace the reciprocating compressor rod packing to maintain volumetric flow rate at or below 2 scfm per cylinder.
Process controllers (except for those located at sites in Alaska without access to electrical power)	Zero VOC and GHG emissions.
Process controllers (at sites in Alaska without access to electrical power)	➢ 95 percent VOC and GHG emissions reduction using an emissions control device. OR ➢ For continuous bleed controllers, the bleed rate must be 6 standard cubic feet per hour (scfh) or less unless the owner/operator demonstrates that there is a functional need requiring a bleed rate higher than 6 scfh; and ➢ For intermittent vent controllers, zero emissions during idle periods.
Pumps (except for those located at sites without electrical power and fewer than three natural gas-driven diaphragm pumps)	Zero VOC and GHG emissions.

Affected Facility (Emission Source)	Final Subpart OOOOb Control Requirements
Pumps (located at sites without electrical power and fewer than three natural gas-driven diaphragm pumps)	➢ Zero VOC and GHG emissions by routing emissions to a process if there is a vapor recovery unit onsite. ➢ 95 percent VOC and GHG emissions reduction if there is no vapor recovery unit onsite but there is a control device onsite that reduces emissions by 95 percent or greater. ➢ Emissions reduction achieved by a control device onsite if there is no vapor recovery unit onsite or a control device onsite that reduces emissions by 95 percent or greater. ➢ Emissions control not required if: ➢ It is technically infeasible to route emissions to a process or an existing control device. ➢ There is no vapor recovery unit or control device onsite.
Fugitive emissions from well sites and compressor stations	Monitoring and repair of fugitive emission components using optical gas imaging (OGI) with Method 21 as an alternative at 500 parts per million (ppm).
Equipment leaks at natural gas processing plants	Leak detection and repair (LDAR) program with bimonthly OGI following procedures in Appendix K.
Sweetening units	Achieve, at a minimum, a sulfur dioxide (SO_2) emission reduction efficiency that is determined by the information specified in Tables 1 and 2 of 40 CFR part 60, subpart OOOOb.

Affected Facility (Emission Source)	Final Subpart OOOOb Control Requirements
Storage Vessels: A Single Storage Vessel or Tank Battery with potential to emit 6 tpy or more of VOC or 20 tpy or more of methane	Control VOC and GHG emissions control device to reduce emissions by 95 percent.

A complete copy of the final rule can be found in the Federal Register (89 FR 16820, March 8, 2024). The codification of the final rule's subpart can be found in the electronic CFR (eCFR): Subpart OOOOb – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after December 6, 2022, at **http://www.ecfr.gov/**. The docket for this rule, which includes supporting technical documents as well as public comments, is available on **http://www.regulations.gov/**, docket ID number EPA-HQ-OAR-2021-0317.

1.3 What is the NSPS and EG applicability and compliance timetable?

Table 1-2 presents the applicable dates for Part 60 NSPS and Emissions Guidelines (EG) impacting the Crude Oil and Natural Gas source category.[3]

Table 1-2. Applicable Dates for Subparts Addressed in This Rulemaking

Subpart	Source Type	Applicable Dates
40 CFR part 60, subpart OOOO	New, modified, or reconstructed sources	After August 23, 2011, and on or before September 18, 2015
40 CFR part 60, subpart OOOOa	New, modified, or reconstructed sources	After September 18, 2015, and on or before December 6, 2022
40 CFR part 60, subpart OOOOb (NSPS OOOOb)	New, modified, or reconstructed sources	After December 6, 2022
40 CFR part 60, subpart OOOOc	Existing sources	On or before December 6, 2022

The effective date of the NSPS OOOOb rule that is the subject of this guide is May 7, 2024. We have provided a compliance timetable based on the specific requirements for each of the individual affected facilities in the sections below. [§60.5370b]

The initial compliance period for the rule begins on the compliance date specified for the individual affected facility and ends no later than one year after the compliance date specified for the affected facility. [§60.5410b introductory text] The initial compliance period may be less than one full year. [§60.5410b introductory text] The initial annual reports are due

[3] See the final rule preamble section IX, "Interaction of the Rules and Response to Significant Comments Thereon" for discussion on the applicable dates (89 FR 16868).

90 days after the end of the initial compliance period and subsequent annual reports are due no later than the same date each year as the initial annual report.

1.4 How do I use this guide?

1.4.1 What does the guide cover?

This guide covers the affected facilities under the subpart OOOOb rule as outlined in Table 1-1 above. Although the intended audience for this guide are small business entities, the compliance guide is generally applicable to all entities subject to the rule.

1.4.2 Structure and content of the guide

Section 2 of the guide describes the specific entities and affected facilities and emission sources covered by the rule as outlined in the preamble to the final rule.

Section 3 addresses the requirements owners and operators of oil and natural gas facilities must follow when notified by the EPA of a potential super-emitter emissions event (i.e., 100 kg/hr or more of methane) occurring at their facility.

Sections 4 through 14 address the specific requirements applicable to the affected facilities subject to the rule. Each of those sections includes information such as:

- How to determine the affected facility status of an emission source
- What requirements apply to the affected facility
- When compliance is required
- What testing and monitoring requirements apply
- What notification and reporting requirements apply
- What records must be kept

Section 15 provides an overview of the regulatory entities that implement and enforce the requirements of the rule and covers how to report a violation of the rule.

Section 16 provides additional information that might be helpful in complying with the rule, including:

- Who to contact for further assistance or for questions
- How to find the rulemaking and related documents
- Information about the compliance assurance process (enforcement)
- How to minimize harm and how pollution prevention might affect your operation

This guide also includes three appendices that provide additional detail for specific aspects of the final rule. Appendix A (Conducting A Low Pressure Well Determination), Appendix B (Appendix K Overview) and Appendix C (Control Device Monitoring Requirements).

In this guide, we provide an overview of the requirements in a more easy-to-understand format based on the type of source. We provide citations to CFR rule sections throughout this guide to assist the reader in locating the official rule's wording. For brevity, the nomenclature omits "40 CFR" and "(2024)" in each rule citation, which is common for every citation in this guide. For example, when referring to the official rule section 40 CFR §60.5365b (2024), we simply use §60.5365b. The citations are provided in square brackets following text throughout the guide. For example, the citation would appear as [§60.5365b(f)] after a paragraph of text.

Note also that all references to this "part" refer to 40 CFR part 60 and references to this "subpart" refer to 40 CFR part 60, subpart OOOOb, unless otherwise specified.

For the convenience of the reader, we provide notation boxes throughout the guide that provide useful information such as definitions, insights, notes, or interpretations.

1.4.3 Requirements applicable to all affected facilities

There are several requirements that are common to all affected facilities with respect to submitting annual reports and maintaining records. In addition, there are affected facility specific requirements which are outlined later in this document.

Reporting

- You must submit 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) at **https://cdx.epa.gov/**). You must 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 Web site (**https://www.epa.gov/electronic-reporting-air-emissions/cedri**). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §60.4. 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, regardless of the method in which the report is submitted. [§60.5420b(b) introductory text and (b)(15)]

- The initial annual report is due no later than 90 days after the end of the initial compliance period. The initial compliance period ends no later than 1 year after the compliance date for your affected facility. [§60.5420b(b) introductory text and §60.5410b introductory text]
    - 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. [§60.5420b(b) introductory text]
    - Annual reports may coincide with title V reports if all the required elements of the annual report are included. [§60.5420b(b) introductory text]
    - You may arrange with the Administrator a common schedule on which reports required by subpart OOOOb may be submitted as long as the schedule does not extend the reporting period. [§60.5420b(b) introductory text]
    - The information specified below should be included in all reports. [§60.5420b(b)(1)]
        - 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.
        - An identification of each affected facility being included in the annual report.
        - Beginning and ending dates of the reporting period.
        - 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 this requirement.
        - 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 following information:

- 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, or
- 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.

Recordkeeping

- All records required by subpart OOOOb must be maintained either onsite or at the nearest local field office for at least 5 years.
- Any records required to be maintained by subpart OOOOb that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. [§60.5420b(c) introductory text)]
- The 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. [§60.5420b(c) introductory text)]

1.4.4 Acronyms and abbreviations

Table 1-3 provides a list of acronyms and abbreviations that are used in this guide along with their "long name".

Table 1-3. Explanation of Acronyms and Abbreviations

Acronym	Long Name
ANS	Alaska North Slope
AMEL	Alternative Means of Emissions Limitation
API	American Petroleum Institute
AVO	Audible, Visual and Olfactory
BMPs	Best Management Practices
BSER	Best Systems of Emission Reduction
BTU	British Thermal Units
CAA	Clean Air Act
CDX	Central Data Exchange
CVS	Closed Vent System
CEDRI	Compliance and Emissions Data reporting Interface
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
CPMS	Continuous Parameter Monitoring System
ECD	Enclosed Combustion Device
eCFR	Electronic Code of Federal Regulations

Acronym	Long Name
eDisclosure	Electronic Self-Disclosure
EPA	Environmental Protection Agency
ft	Feet
GHG	Greenhouse Gas
GOR	Gas to Oil Ratio
H_2S	Hydrogen Sulfide
hr/yr	Hour per Year
Low-E	Low Emission
LDAR	Leak Detection and Repair
LT/D	Long Tons per Day
NHV_{CZ}	Combustion Zone NHV
NHV_{dil}	NHV Dilution Parameter
NIE	No Identifiable Emissions
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
OECA	Office of Enforcement and Compliance Assurance
OGI	Optical Gas Imaging
ppm	Parts per Million
ppmv	Parts per Million by Volume
psia	Pounds per Square Inch Absolute
PTE	Potential to Emit
REC	Reduced Emissions Completion
SBREFA	Small Business Regulatory Enforcement Fairness Act of 1996
scmd	Standard Cubic Meters per Day
scf	Standard Cubic Feet
scf/day	Standard Cubic Feet per Day

2.0 What Entities and Affected Facilities are Subject to the Rule?

The entities that could potentially be subject to the rule comprise several categories of activity in the oil and natural gas industry. If an entity operates under the industrial source categories outlined below in Table 2-1, those entities could potentially be subject to the rule.

Table 2-1. Industry Classification of Regulated Entities Affected by Subpart OOOOb

Category and NAICS Code [a]	Examples of Regulated Entities
Industry – 211120	Crude Petroleum Extraction
Industry – 211130	Natural Gas Extraction
Industry - 221210	Natural Gas Distribution
Industry - 486110	Pipeline Distribution of Crude Oil
Industry - 486210	Pipeline Transportation of Natural Gas
Federal Government – N/A	Not Affected
State and Local Government – N/A	Not Affected
Tribal Government - 921150	American Indian and Alaska Native Tribal Governments

a. North American Industry Classification System.

As noted in the preamble to the final rule, this table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by the rule. This table lists the types of entities that the EPA is now aware could potentially be affected; however, other types of entities not listed in the table could also be regulated.

To understand who is subject to the rule's requirements, it is important to understand what types of "affected facilities" are covered by the rule. If an entity owns or operates an affected facility as outlined in the rule, the owner or operator is subject to the rule. An owner or operator may have one or more affected facilities at the same location.

Definition

Affected facility means any apparatus to which the standard is applicable. An owner or operator may have one or several affected facilities at the same location.

Subpart OOOOb applies to owners and operators of affected facilities outlined in Table 2-1 where construction, modification or reconstruction commenced after December 6, 2022. The definition of modification and reconstruction for an affected facility defaults to the definition provided in the General Provisions of 40 CFR subpart 60, except for where a source-specific definition is included in the rule.

Table 2-2. Types of Affected Facilities and Emissions Events Subject to Subpart OOOOb

Guide Section	Affected Facility/Emissions Events	Location
3.0	Super-Emitter Events	All
4.0	Wells (Oil and Gas)	N/A
4.1	Well Completions (for hydraulically fractured wells)	All [a]
4.2	Associated Gas	N/A
4.3	Liquids Unloading	Gas well sites
5.0	Centrifugal compressors	All (except located at well sites)
6.0	Reciprocating compressors	All (except located at well sites)
7.0	Process controllers	All [a]
8.0	Pumps	All [a]
9.0	Storage Vessels	All [a]
10.0	Collection of Fugitive Emissions Components	Well sites, centralized production facilities, and compressor stations
11.0	Collection of Fugitive Emissions Components – Alternative Standards	Well sites, centralized production facilities, and compressor stations
12.0	Equipment Leaks at Natural Gas Processing Plants (Except Compressors)	All natural gas processing plants
13.0	Sweetening Units Processing Plants	All natural gas processing plants

a. Some exemptions or emission thresholds apply. See specific guide section for description of affected facility and requirements.

3.0 Standards for Super-Emitter Events

3.1 What is the Super-Emitter Program?

Subpart OOOOb includes a Super-Emitter Program, which requires owners and operators of oil and natural gas facilities to investigate large emission events at their facilities (i.e., super-emitter events) when notified by the EPA that a certified third-party entity has detected such events at their facilities.

Entities seeking certification as third-party notifiers should refer to §60.5371b and the EPA's Super-Emitter Portal at ***https://www.epa.gov/compliance/super-emitter*** for additional information on how to obtain approval.

Definitions

Super-emitter event is 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 a quantified emission rate of 100 kilograms per hour (kg/hr) of methane or greater.

Third-party entity is an individual, corporation, partnership, association, State, municipality, political subdivision of a State, and any agency, department, or instrumentality of the United States and any officer, agent, or employee thereof, excluding the owner or operator of the site where the super-emitter event is detected, the EPA Administrator, or the EPA-delegated authority.

An entity can apply to the EPA for approval as a third-party notifier of super-emitter events. Certified third-party notifiers provide information to the EPA to demonstrate that a super-emitter event has occurred or is occurring. If the EPA determines that a certified third-party notification it has received is complete and does not contain erroneous or inaccurate information, the EPA will provide the notification to the owner or operator of the oil and natural gas facility identified in the notification. The EPA will also post the notification, except for the owner/operator name, to its super-emitter portal at **https://www.epa.gov/super-emitter**.

Third-party notifiers must use a method that has been approved under §60.5398b(d) for one of the following technologies to detect super-emitter events:

- Satellite detection of methane emissions,
- Remote-sensing equipment on aircraft, or
- A mobile monitoring platform.

3.2 How do I determine if my facility is subject to Super-Emitter Event requirements?

The super-emitter event requirements apply to you if you are 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) who receives a notification from the EPA of a super-emitter event that has been identified at your facility.

3.3 How do I comply?

If you receive a super-emitter event notification from the EPA, the requirements that apply to you depend on the location of your oil and gas facility relative to the location of the super-emitter event reported in the notification as well as any identified source(s) of the emissions for the super-emitter event. If you own or operate an oil and natural gas facility that is not within 50 meters of the location provided in a super-emitter event notification from the EPA, you must report this to the EPA, and no further action is required. If your oil and natural gas facility is within 50 meters of the provided super-emitter event location, you are required to conduct an investigation to determine the source of the super-emitter event. [60.5371b(e)(1)(i) and (ii)]

If you must determine the source of the super-emitter event (i.e., your oil and gas facility is within 50 meters of the location identified in the super-emitter event report), your requirements for further action depend on the outcome of your super-emitter source investigation as follows:

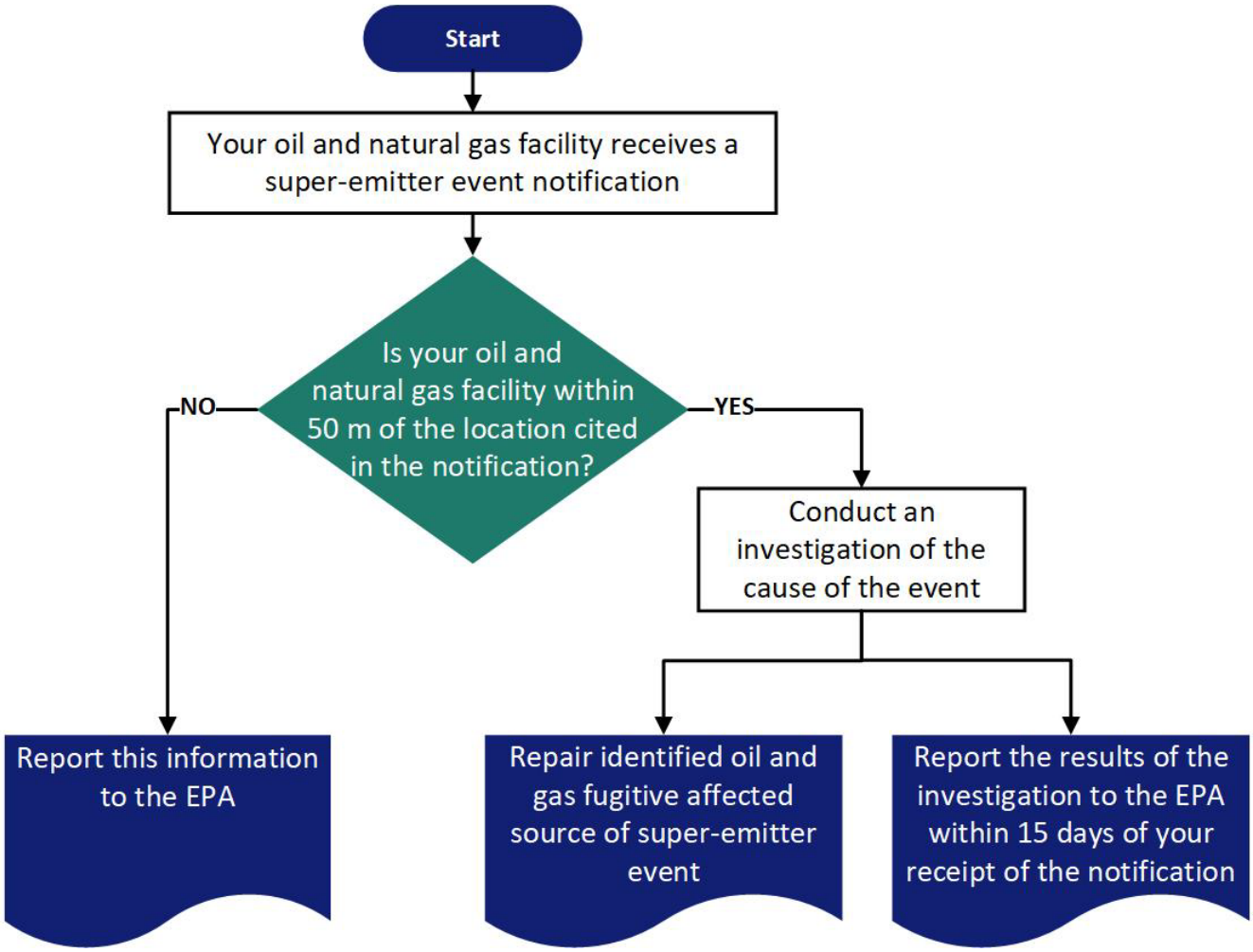
- If the source is a subpart OOOOb affected facility,
  - and the source is a fugitive emissions component, you must repair the component according to the fugitive emission component repair requirements of the rule.
  - and the source is any other subpart OOOOb affected facility, you must identify the equipment and applicable subpart OOOOb requirements in the super-emitter investigation report.

- If the source is not a subpart OOOOb affected facility, you must report this information in the super-emitter investigation report.[4]
- If you cannot identify the super-emitter source, you must report this and provide additional information in your super-emitter investigation report.

Figure 3-1 provides a graphical presentation of the process for determining which actions you must take in response to the receipt of a super-emitter notification from the EPA.

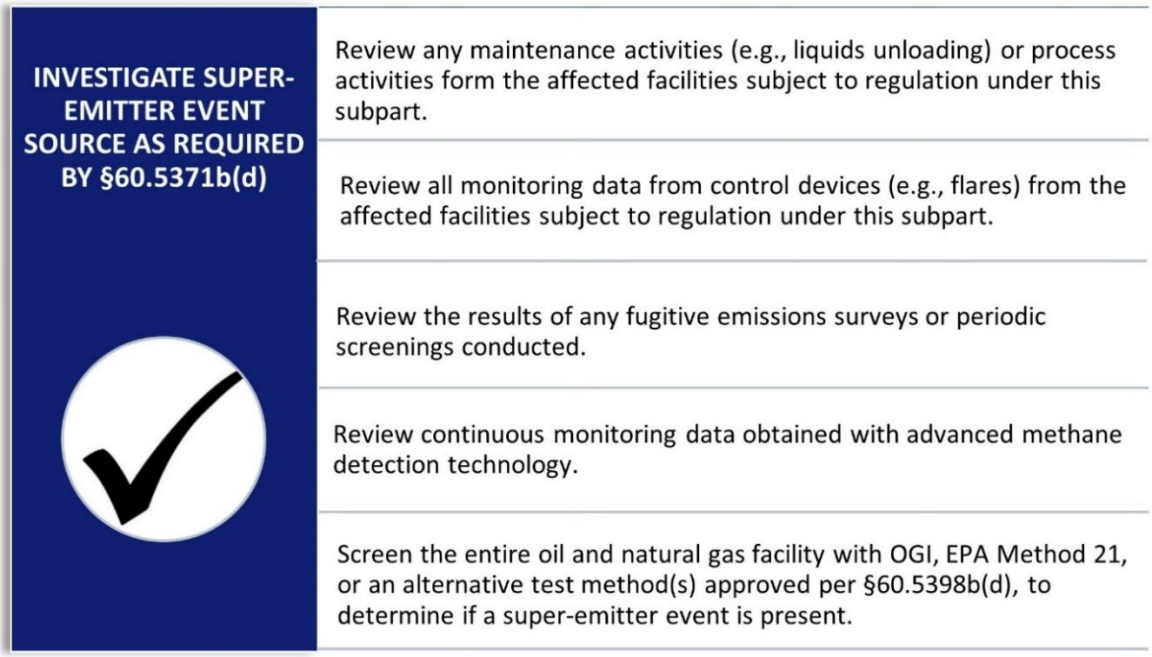
[4] Although not the subject of this guide, the Super-Emitter Program also applies to oil and natural gas facilities subject to 40 CFR part 60, subparts OOOO, OOOOa and OOOOc under §60.5371, §60.5371a, and §60.5388c, respectively.

Figure 3-1. Requirements for Super-Emitter Events



If you must investigate the source of super-emitter event (i.e., your facility is within 50 meters of the location provided in a super-emitter event notification from the EPA), the investigation may include, but is not limited to, the activities listed in Figure 3-2.

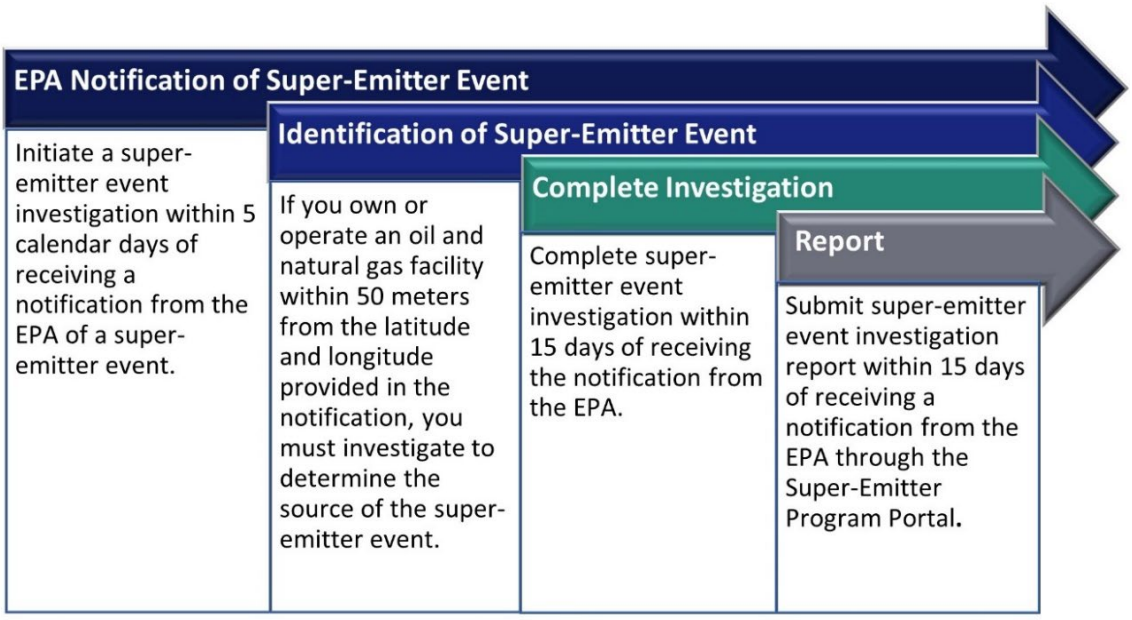
Figure 3-2. Requirements for Super-Emitter Event Source Investigations



3.4 When must I comply?

If you are an owner or operator of an oil and natural gas facility who receives a super-emitter event notification from the EPA, you must comply with the compliance schedule shown in Figure 3-3 (Compliance Schedule for Super-Emitter Events).

Figure 3-3. Compliance Schedule for Super-Emitter Events



3.5 What, when, and to whom must I report?

You must submit the results of the super-emitter event investigation via the Super-Emitter Portal. The reporting requirements are provided in §60.5371b(e)(1).

If your oil and natural gas facility is not within 50 meters of the latitude and longitude provided in the super-emitter event notification, the only super-emitter event investigation reporting requirements are the following:

- Notification Report ID from the super-emitter event notification.
- Identification that your oil and natural gas facility is not within 50 meters of the latitude and longitude provided in the EPA notification.

If your oil and natural gas facility is within 50 meters of the latitude and longitude provided in the super-emitter event notification, report the following information via the Super-Emitter Program Portal:

1. Notification Report ID from the super-emitter event notification.
2. Identification that your oil and natural gas facility is within 50 meters of the latitude and longitude provided in the EPA notification.
3. Facility name, physical address, applicable ID Number (e.g., EPA ID Number, American Petroleum Institute [API] Well ID Number), owner, operator, or responsible official name and email address.
4. Identification of whether there is an affected facility or associated equipment subject to regulation under subpart OOOOb.
5. Indication of whether you were able to identify the source of the super-emitter event.
    a. If you indicate that you were able to identify the source of the super-emitter event, you must report the information listed in items 6 through 8.
    b. If you indicate you were unable to identify the source of the super-emitter event, you must certify that you conducted the investigations specified in Figure 3-2 for all affected facilities subject to NSPS OOOOb and associated equipment, and that you determined none of these are the source of the super-emitter event. You are not required to report the information listed in items 6 through 8.

If you have identified a demonstrable error in the notification, the report may include a statement of the demonstrable error.

6. The source(s) of the super-emitter event.
7. Identification of whether the source of the super-emitter event is equipment subject to NSPS OOOOb. If so, you must identify the equipment and applicable rule requirements.
8. Indication of whether the super-emitter event is ongoing at the time of the report submittal.
    a. If the super-emitter event has stopped, the end date of the event.
    b. If the super-emitter event is ongoing, you must update the initial report to indicate the end date of the event within 5 days of the end of the event.

4.0 GHG and VOC Standards for Well Affected Facilities

4.1 How do I determine if my well is an affected facility?

A well affected facility is a single well drilled for the purpose of producing oil or natural gas. [§60.5365b(a)] that commenced construction, reconstruction, or modification after December 6, 2022. [§60.5365b introductory text] While there is a single definition of well affected facility, there are three different well standards in subpart OOOOb which may apply, depending on the type of well (oil or gas well). These include requirements for well completions, gas well liquids unloading, and associated gas well operations. Some of the standards only apply to gas wells (e.g., gas well liquids unloading), while other standards apply to any type of well (e.g., well completions). See Table 4-1 (Well Standards by Well Type) for an overview of the well standards by well type.

Table 4-1. Well Standards by Well Type

Well Type	Well Completions	Liquids Unloading	Associated Gas
Oil Well	☑		☑
Gas Well	☑	☑	

In addition to the modification provisions in subpart A of part 60 [§60.14], a "modification" of an existing well occurs when:

- An existing well is hydraulically fractured, or
- An existing well is hydraulically refractured.

A liquids unloading event is not considered a modification for the purposes of a well affected facility. [§60.5365b(a)]

Definitions

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.

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.

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.

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.

4.2 Well Completions

The well completion requirements apply to a well affected facility that conducts a well completion operation with hydraulic fracturing or refracturing.

Definition

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a well completion affected facility.

4.2.1 How do I comply?

The well completion requirements vary depending on the type of well at the well affected facility. The well completion standards apply initially and each time there is a well completion operation. An existing non-low pressure, non-delineation, or non-wildcat well that is hydraulically refractured is subject to the NSPS as a modified well but is exempt from the well completion operation standards when it meets the requirements of §60.5375b(a)(1) through (3). These wells also must submit the reports required by §60.5420b(b)(2)(i) through (iv) and (b)(2)(xvi) and maintain the records required by §60.5420b(c)(1)(viii). [§60.5375b(h)]

There are three types of well completion requirement scenarios:

- **Scenario One (Low gas to oil ratio (GOR)).** [§60.5375b(g)] A low GOR well is a well affected facility with less than 300 scf of gas per stock tank barrel of oil produced. If you are the owner or operator of this type of well, you do not have any performance requirements (i.e., work practice or control requirements) for your well completions but you are required to:
  - Make a determination that your well has a GOR of less than 300 scf of gas per stock tank of oil produced. The determination must include supporting analysis that was performed as a basis for that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field. [§60.5375b(g)]
  - Maintain records of the determination. [§60.5375b(g); §60.5420b(c)(1)(vi)]
  - Demonstrate initial compliance by keeping a record of the determination. [§60.5375b(c); §60.5410b(a)(3)]

- Demonstrate continuous compliance by submitting the reports in §60.5420b(b)(1) and (2) and maintaining the records in §60.5420b(c)(1)(vi). [§60.5375b(d); §60.5415b(a)]

- **Scenario Two (Low pressure, delineation, and wildcat wells).** [§60.5375b(f)] These wells are required to:
  - Comply with the requirements of §60.5375b(b), (f)(3), and (4). See Figure 4-1 (Performance Requirements for Low Pressure, Delineation and Wildcat Wells) for a summary overview of the requirements for these wells.
  - Demonstrate Initial Compliance [§60.5375b(c); §60.5410b(a)] See Figure 4-3 (Initial Compliance Requirements for Well Completion Operations at Well Affected Facilities) for a summary overview of the initial compliance requirements.
  - Demonstrate Continuous Compliance. [§60.5375b(d); §60.5410b(a)] See Figure 4-4 (Continuous Compliance Requirements for Well Completion Operations at Well Affected Facilities) for a summary overview of the continuous compliance requirements.
- **Scenario Three (All other wells).** (i.e., non-low pressure, non-delineation, and non-wildcat wells). These wells are required to:
  - Comply with the requirements of §60.5375b(a)(1) through (3) and (b). See Figure 4-2 (Requirements for Non-Low Pressure, Non-Delineation and Non-Wildcat Well Affected Facilities) for a summary overview of the requirements for these wells.
  - Demonstrate Initial Compliance. [§60.5375b(c); §60.5410b(a)] See Figure 4-3 (Initial Compliance Requirements for Well Completion Operations at Well Affected Facilities) for a summary overview of the initial compliance requirements.
  - Demonstrate Continuous Compliance. [§60.5375b(d); §60.5410b(a)] See Figure 4-4 (Continuous Compliance Requirements for Well Completion Operations at Well Affected Facilities) for a summary overview of the continuous compliance requirements.

Definitions

Delineation well means a well drilled to determine the boundary of a field or producing reservoir.

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.

Figure 4-1.Performance Requirements for Low Pressure, Delineation and Wildcat Wells

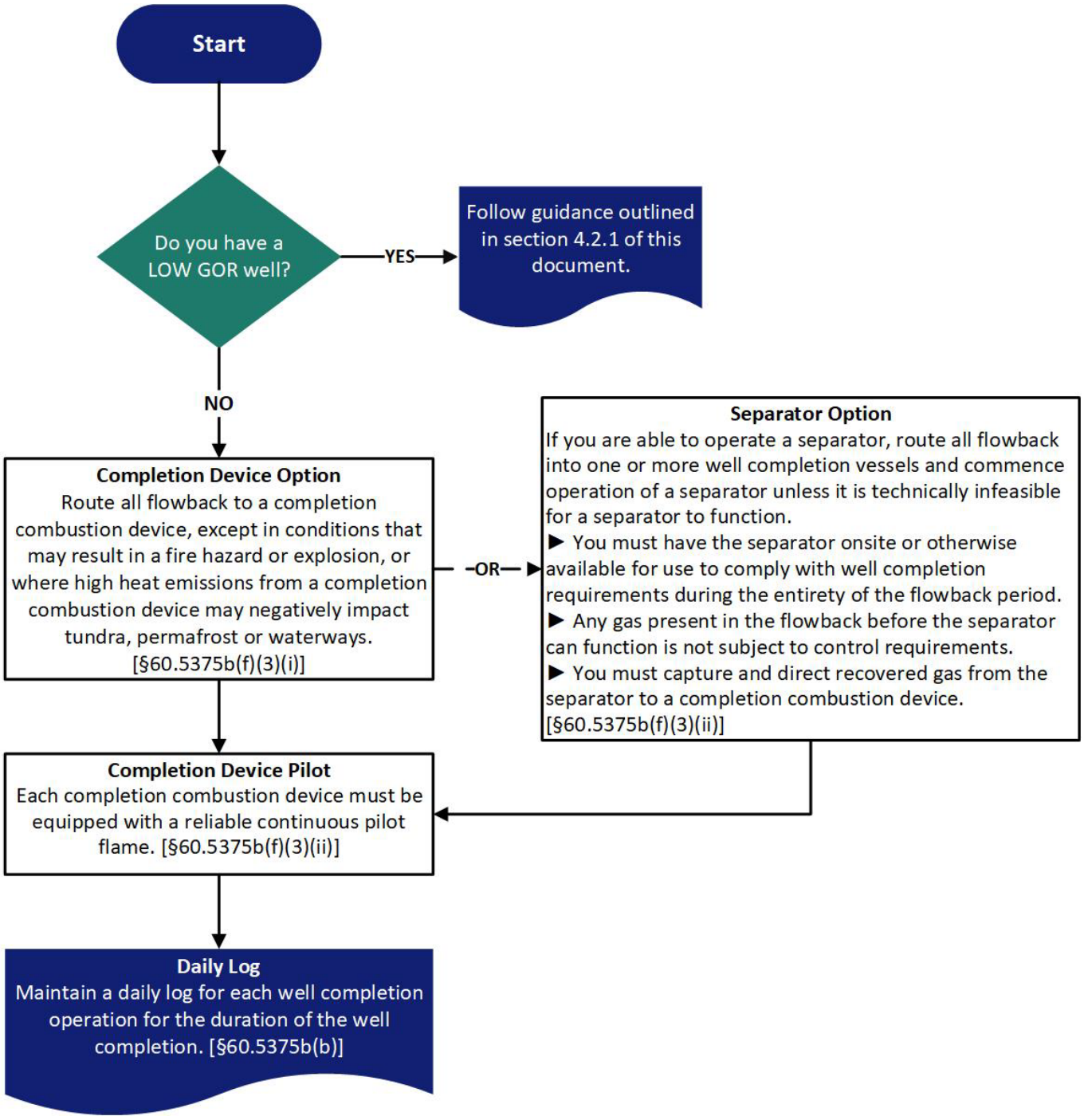
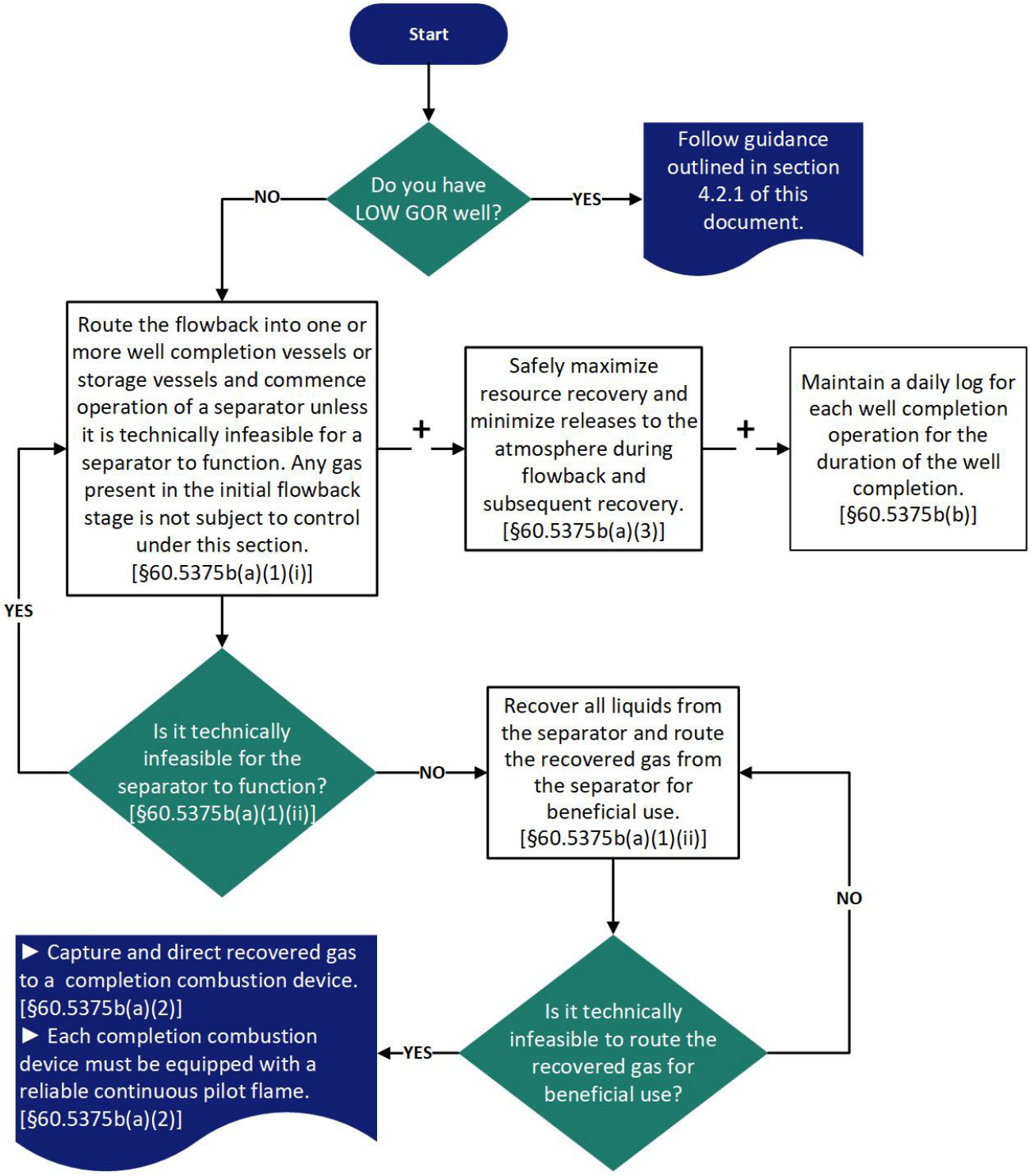


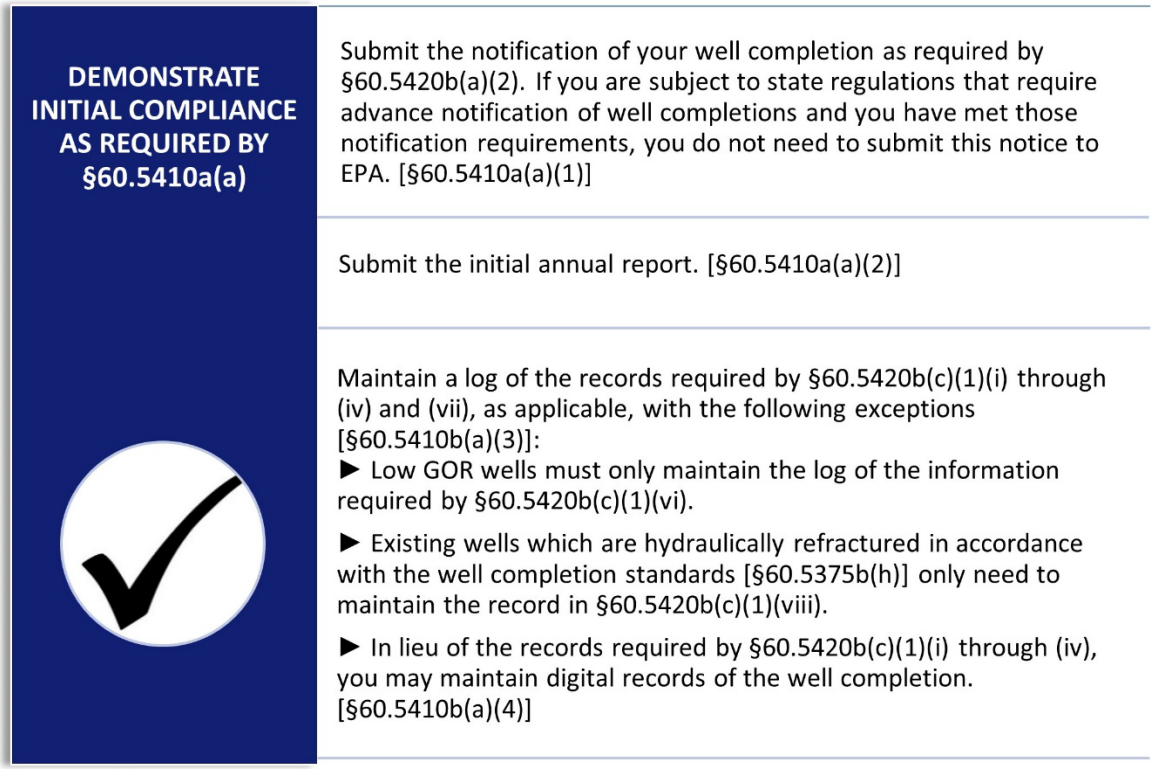
Figure 4-2. Requirements for Non-Low Pressure, Non-Delineation and Non-Wildcat Well Affected Facilities



4.2.2 How do I demonstrate initial and continuous compliance?

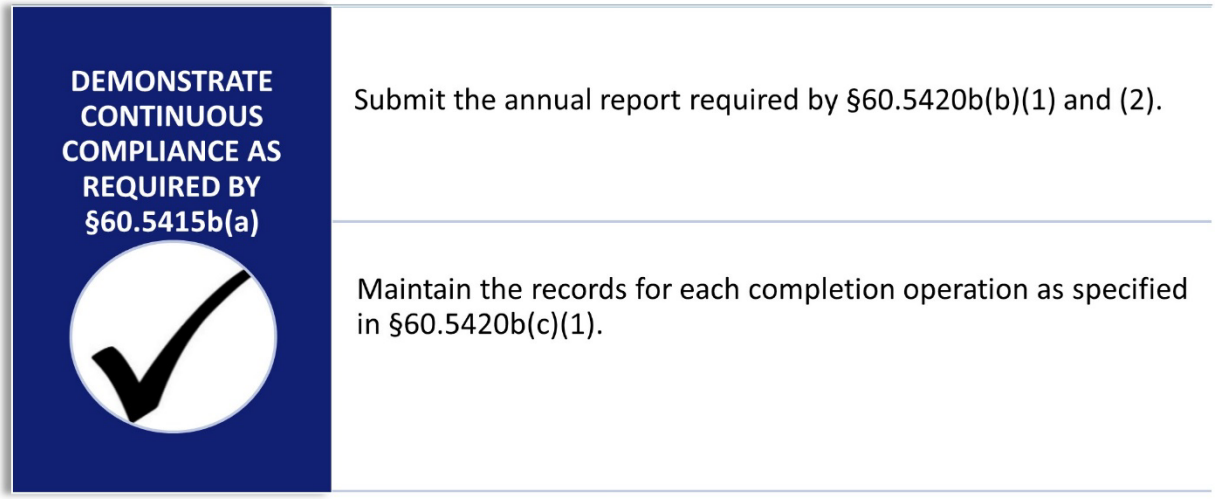
To demonstrate initial compliance, please refer to the summary overview of requirements in Figure 4-3 (Initial Compliance Requirements for Well Completion Operations at Well Affected Facilities) for the initial compliance requirements.

Figure 4-3. Initial Compliance Requirements for Well Completion Operations at Well Affected Facilities



To demonstrate continuous compliance, please refer to the summary overview of requirements in Figure 4-4 (Continuous Compliance Requirements for Well Completion Operations at Well Affected Facilities).

Figure 4-4. Continuous Compliance Requirements for Well Completion Operations at Well Affected Facilities

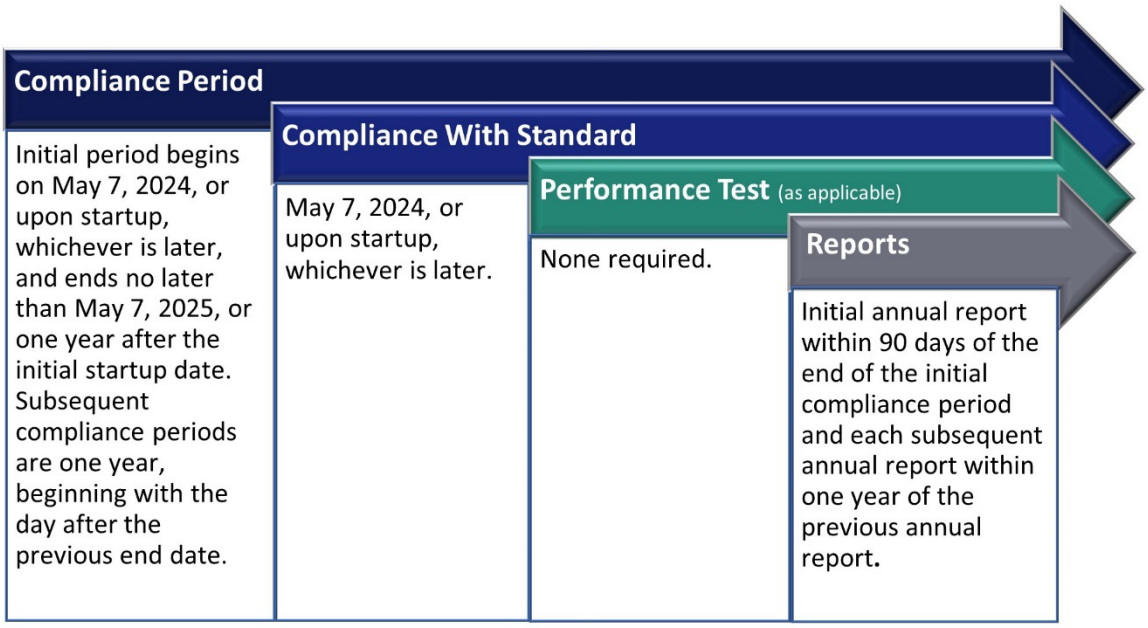


4.2.3 When must I comply?

The compliance schedule is the same for all three types of well affected facilities. You must be in compliance no later than May 7, 2024, or upon initial startup, whichever is later. [§60.5370b(a)] The initial compliance period begins on May 7, 2024, or upon startup of flowback, whichever is later, and ends no later than one year after the initial startup date or no later than May 7, 2025. [§60.5410b introductory text] You must submit your initial annual report within 90 days of the end of the initial compliance period, as described above and submit each subsequent annual report within one year of the previous annual report. Initial performance tests must be completed within 180 days of startup or by May 7, 2024, whichever is later. [§60.5413b(b)(5)]

Figure 4-5 (Compliance Schedule for Well Completion Operations) provides an overview of the compliance schedule for well completion operations.

Figure 4-5. Compliance Schedule for Well Completion Operations



4.2.4 What testing or monitoring is required?

There are no testing or monitoring requirements applicable to well completions at well affected facilities.

4.2.5 What, when and to whom must I report?

You are required to submit a notification of the well completion operation as required in §60.5420b(a)(2) for all wells, except low GOR well affected facilities do not have to submit the notification. If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you do not have to submit another notification of the well completion operation to the EPA.

Completion combustion devices required by the well completion standards are not subject to §§60.5412b, 60.5413b, or 60.5417b, but they must be equipped with a reliable continuous pilot flame.

In addition to the information outlined in section 1.4.3 (Requirements applicable to all affected facilities) of this guide, you must include the information outlined in §60.5420b(b)(2) of the rule in your initial and subsequent annual reports for your well affected facility.

An existing non-low pressure, non-delineation, or non-wildcat well that is hydraulically refractured which is exempt from the well completion operation standards because it meets the requirements of §60.5375b(a)(1) through (3) must submit the reports required by §60.5420b(b)(2)(i) through (iv) and (b)(2)(xvi). [§60.5375b(h)].

A well completion following hydraulic fracturing or refracturing is reported once only in the first annual report following the completion event. Subsequent completions of the same well following refracturing are reported in the annual report which covers the time period in which the well completion operation occurred.

4.2.6 What records must I keep?

You must maintain the records for each well completion operation. Specifically, you must maintain the records outlined in §60.5420b(c)(1), as applicable.

An existing non-low pressure, non-delineation, or non-wildcat well that is hydraulically refractured which is exempt from the well completion operation standards because it meets the requirements of §60.5375b(a)(1) through (3) must maintain the records required by §60.5420b(c)(1)(viii). [§60.5375b(h)]

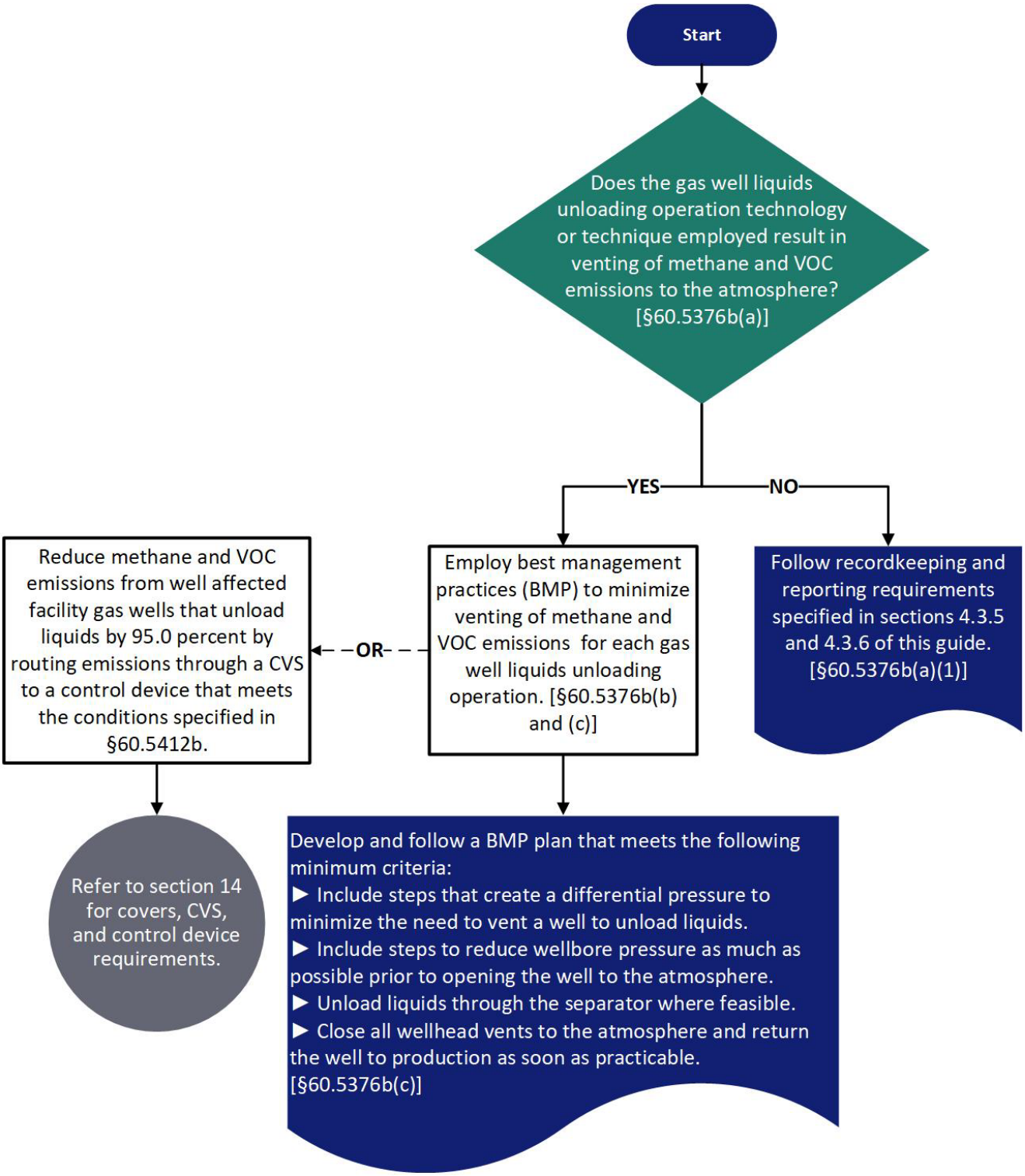
4.3 Liquids Unloading

The liquids unloading requirements apply to a well affected facility which is a gas well and which unload liquids that have accumulated over time in the well, and which are impeding or halting production.

4.3.1 How do I comply?

The compliance requirements vary depending on whether your liquids unloading operation technology or technique results in emissions to the atmosphere. The liquids unloading standards apply each time there is a liquids unloading operation at a gas well affected facility. Please refer to Figure 4-6 (Requirements for Liquids Unloading Operations) for a summary overview of requirements.

Figure 4-6. Requirements for Liquids Unloading Operations



4.3.2 How do I demonstrate initial and continuous compliance?

To demonstrate initial compliance, please refer to the summary overview of requirements in Figures 4-7 (Initial Compliance Requirements for Liquids Unloading Operations at Well Affected Facilities – Non-Venting and Venting with Implementation of Best Management Practices [BMPs]) and 4-8 (Initial Compliance Requirements for Liquids Unloading Operations at Well Affected Facilities – 95 Percent Control of Vented Emissions).

Figure 4-7. Initial Compliance Requirements for Liquids Unloading Operations at Well Affected Facilities – Non-Venting and Venting with Implementation of BMPs

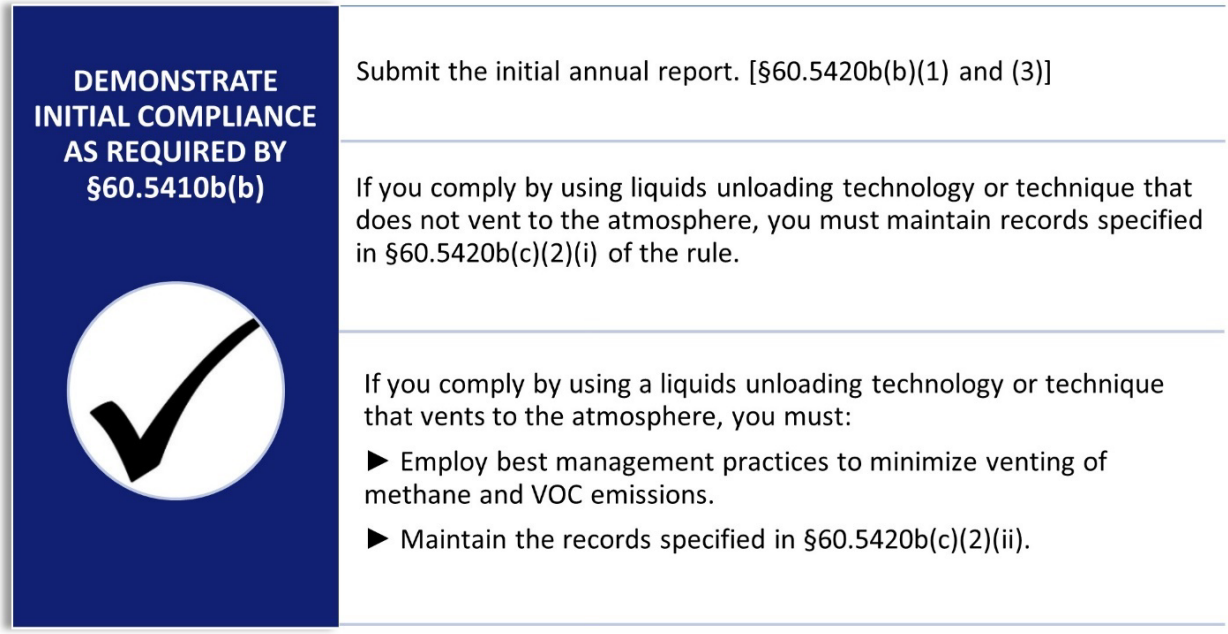
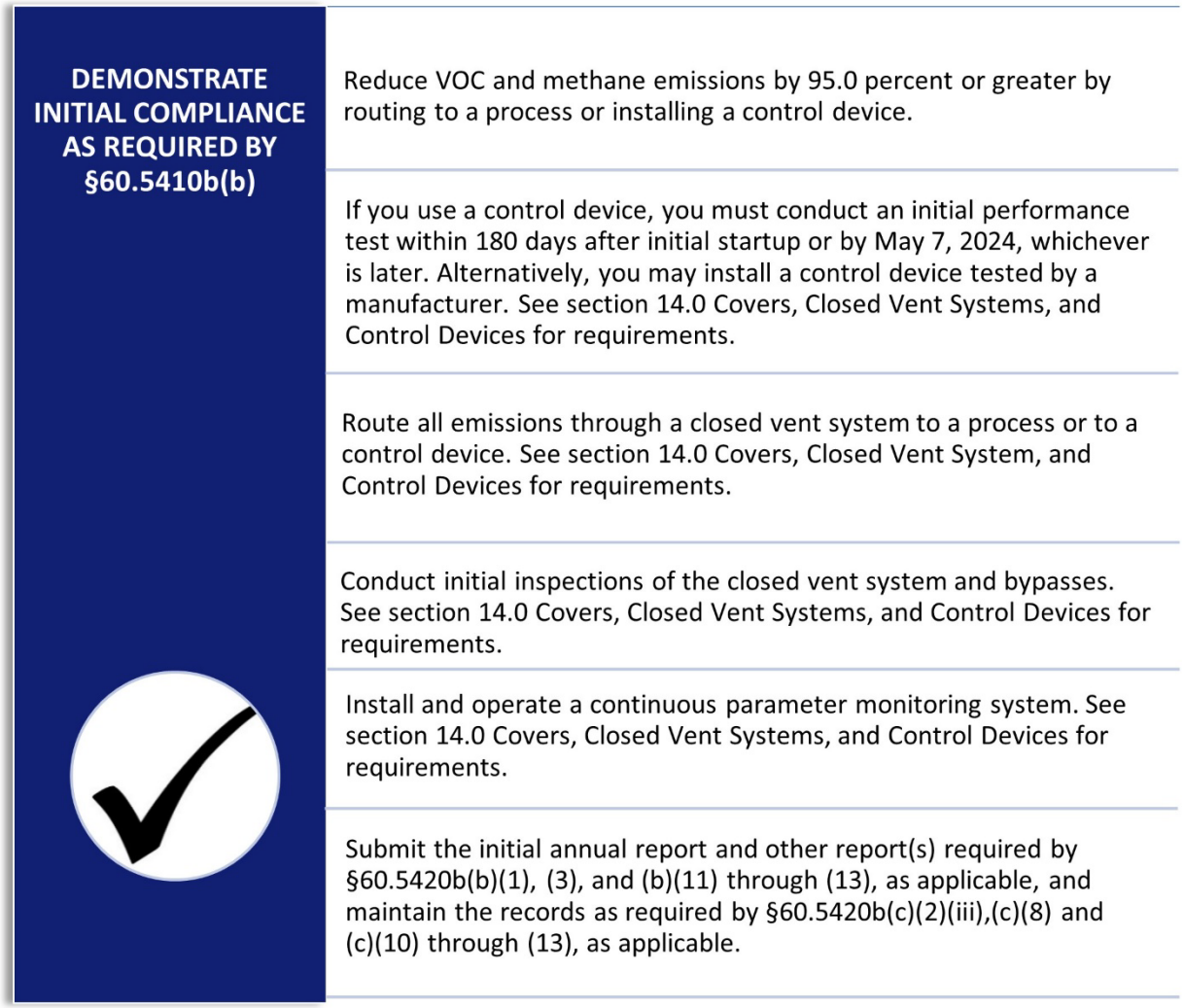


Figure 4-8. Initial Compliance Requirements for Liquids Unloading Operations at Well Affected Facilities – 95 Percent Control of Vented Emissions



To demonstrate continuous compliance, please refer to the summary overview of requirements in Figures 4-9 (Continuous Compliance Requirements for Liquids Unloading Operations at Well Affected Facilities – Non-Venting and Venting with Implementation of BMPs) and 4-10 (Continuous Compliance Requirements for Liquids Unloading Operations at Well Affected Facilities – 95 Percent Control of Vented Emissions).

Figure 4-9. Continuous Compliance Requirements for Liquids Unloading Operations at Well Affected Facilities – Non-Venting and Venting with Implementation of BMPs

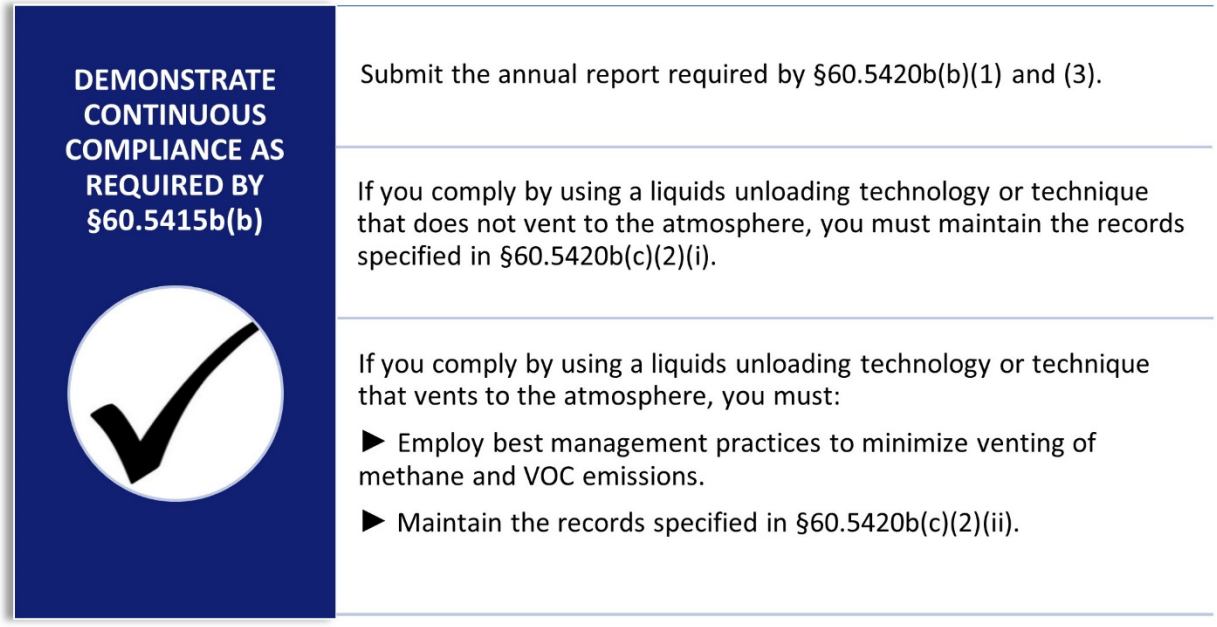
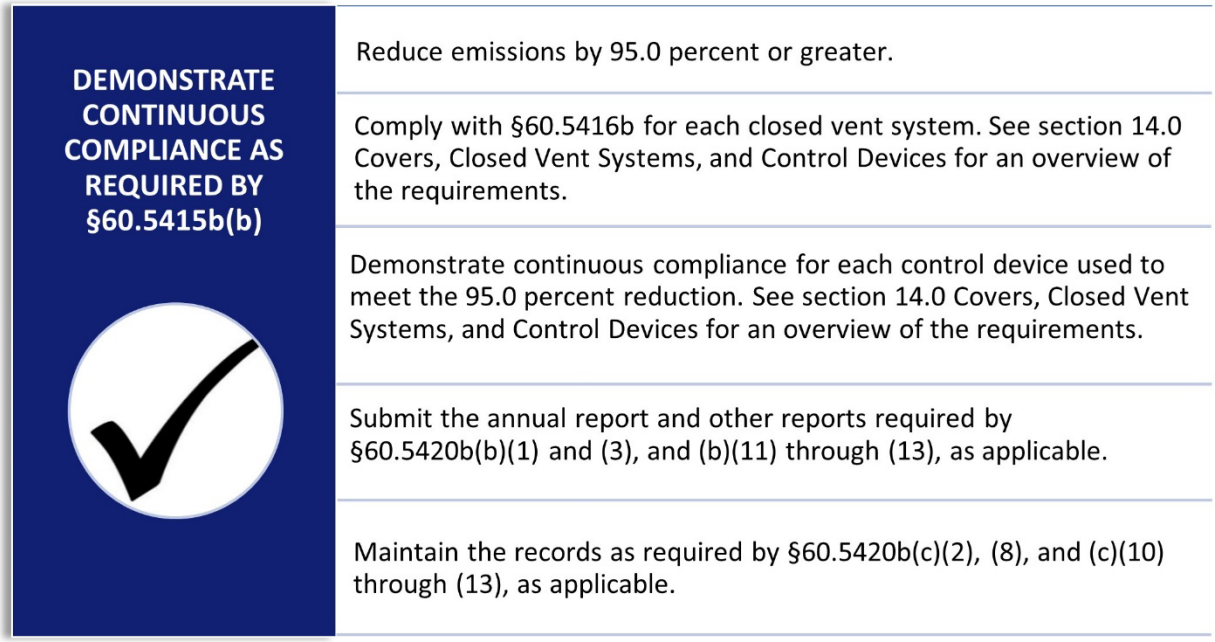


Figure 4-10. Continuous Compliance Requirements for Liquids Unloading Operations at Well Affected Facilities – 95 Percent Control of Vented Emission

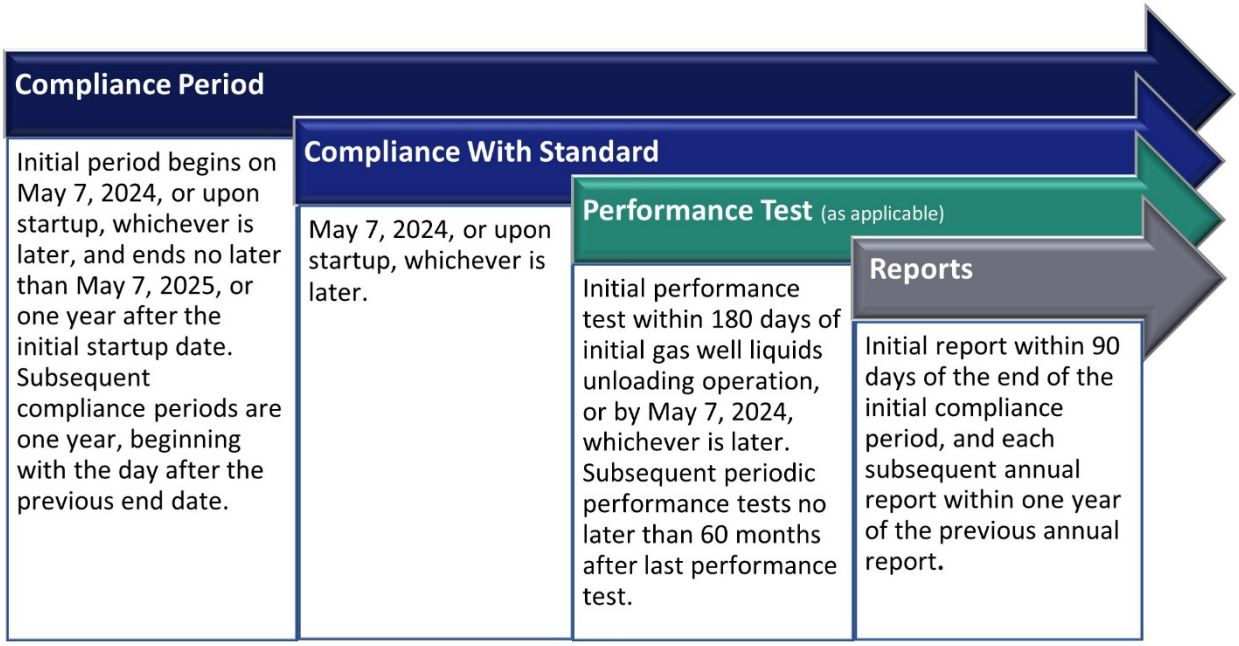


4.3.3 When must I comply?

You must be in compliance no later than May 7, 2024, or upon initial startup, whichever is later. [§60.5370b(a)] The initial compliance period begins on May 7, 2024, or upon initial startup, whichever is later, and ends no later than one year after the initial startup date or no later than May 7, 2025. [§60.5410b introductory text] You must submit your initial annual report within 90 days of the end of the initial compliance period, as described above, and submit each subsequent annual report within one year of the previous annual report. [§60.5420b(b)] You must conduct an initial performance test within 180 days of initial gas well liquids unloading operation or by May 7, 2024, whichever is later. [§60.5413b(b)(5)]

Figure 4-11 (Compliance Schedule for Liquids Unloading Operations) provides a summary overview of the compliance schedule for liquids unloading operations.

Figure 4-11. Compliance Schedule for Liquids Unloading Operation



4.3.4 What testing or monitoring is required?

If your liquids unloading event does not result in venting to the atmosphere, you are not subject to any testing or monitoring requirements.

If your liquids unloading event results in venting to the atmosphere but you are complying by meeting BMPs to minimize emissions to the maximum extent possible, you are not subject to any testing or monitoring requirements.

If your liquids unloading event results in venting to the atmosphere and you are complying by routing emissions from your liquids unloading operation through a closed vent system (CVS) to a control device, you must meet the testing and monitoring requirements provided in section 14.0 (Covers, Closed Vent Systems, and Control Devices) of this guide.

4.3.5 What, when, and to whom must I report?

In addition to the information outlined in section 1.4.3 (Requirements applicable to all affected facilities) of this guide, you are also required to include the information outlined in §60.5420b(b)(3) of the rule in your initial and subsequent annual reports. If you use a CVS and control device to comply with the standards, you also must submit the applicable information in §60.5420b(b)(11) through (13) of the rule.

4.3.6 What records must I keep?

You must maintain records for each liquids loading operation. Specifically, you must maintain the records outlined in §60.5420b(c)(2) of the rule, as applicable. In addition, if you use a CVS and control device to comply with the standards, you must maintain the records in §60.5420b(c)(8) and (c)(10) through (13) of the rule, as applicable.

4.4 Associated Gas

The associated gas requirements apply to wells operated primarily for oil production which release natural gas from liquid hydrocarbons during the initial stage of separation after the well head. Associated gas production begins at the startup of production after the flowback period ends. For requirements for gas generated during flowback, see section 4.2 "Well Completions."

Definition

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.

The requirements, and compliance schedules, differ for associated gas wells based on when the well was constructed, reconstructed, or modified.

- For wells that commence construction after April 7, 2026, there are two methods of compliance: (1) routing the associated gas to a sales line or (2) using the associated gas for another beneficial purpose that does not involve routing to a flare or control device.
- For wells that commence construction between May 7, 2024, and April 7, 2026 [§60.5377b(b)], there are three methods of compliance: (1) routing the associated gas to a sales line, (2) using the associated gas for another beneficial purpose that does not involve routing to a flare or control device, or (3) routinely routing the gas to a flare or control device that achieves 95 percent reduction in VOC and methane. Use of the third option requires an annual demonstration and certification that every potential non-flaring/route to control option is technically infeasible. Further, this option is not available to these wells after April 7, 2026. After that time, the associated gas must comply with one of the first two options.
- For wells that commenced construction between December 6, 2022, and May 7, 2024, and wells that undergo reconstruction after December 6, 2022, there are three methods of compliance: (1) routing the associated gas to a sales line, (2) using the associated gas for another beneficial purpose that does not involve routing to a flare or control device, or (3) routinely routing the gas to a flare or control device that achieves 95 percent reduction in VOC and methane. The third option is available to these wells indefinitely, pending an annual demonstration and certification that every potential non-flaring/route to control option is technically infeasible.

Section 4.4.1 describes how to comply with the standards for routing the associated gas to a sales line or using the gas for another beneficial purpose that does not involve routing to a flare or control device. For wells complying with one of these standards, the rule allows temporary routing to a flare/control device. This is described in section 4.4.2.

In addition, wells are allowed to temporarily vent the associated gas in specific and limited circumstances. These circumstances and the compliance requirements are described in section 4.4.3.

Section 4.4.4 summarizes the compliance requirements for associated gas that is routinely routed to a flare or control device that reduces VOC and methane emissions by 95 percent. This section also describes the requirement to perform the annual demonstration and certification of technical infeasibility that is required to utilize this compliance option.

4.4.1 How Do I Comply with the Standards to Route the Associated Gas to a Sales Line or to Use the Associated Gas for Another Beneficial Purpose That Does Not Involve Routing to a Flare or Control Device?

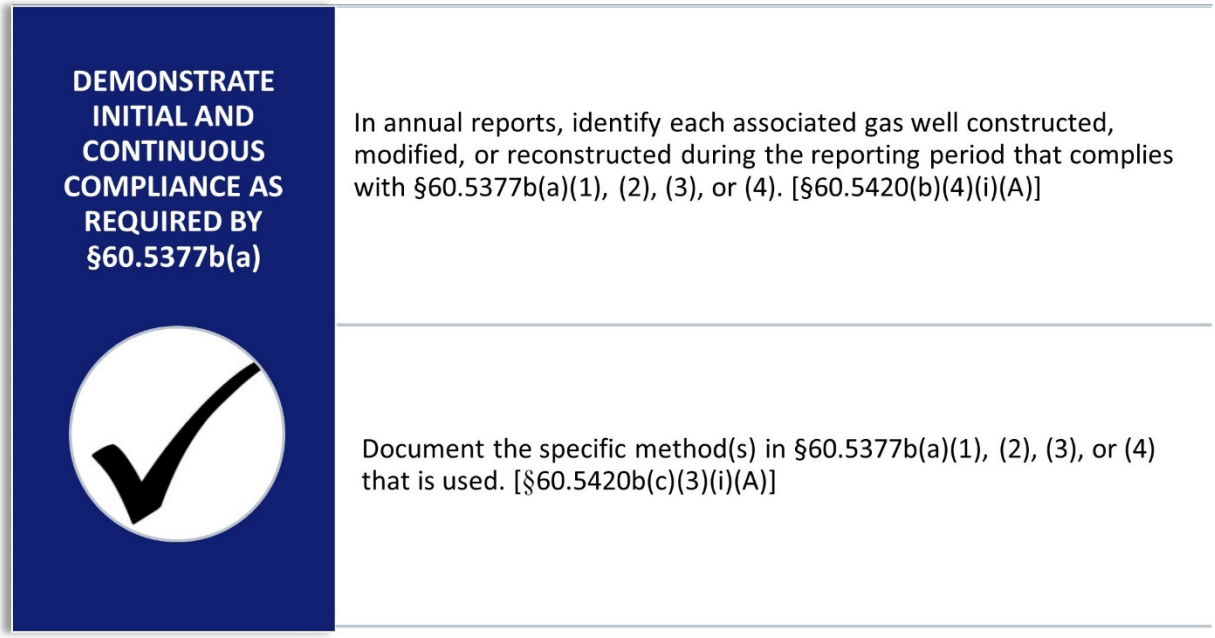
The rule specifically includes three specific end-use options and one general option for compliance.

- 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. [§60.5377b(a)(1)]
- Recover the associated gas from the separator and use the recovered gas as an onsite fuel source. [§60.5377b(a)(2)]
- Recover the associated gas from the separator and reinject the recovered gas into the well or inject the recovered gas into another well. [§60.5377b(a)(4)]
- In addition, the rule includes the generic option to 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. [§60.5377b(a)(3)]

Compliance with one of these standards is straightforward. You must identify in each annual report each associated gas well constructed, modified, or reconstructed during the reporting period that complies with §60.5377b(a)(1), (2), (3), or (4) [§60.5420b(b)(1) and (4)], and you must maintain documentation of the specific method(s) in §60.5377b(a)(1), (2), (3), or (4) that is used. [§60.5420b(c)(3)(i)(A)]

As noted above, for wells that commence construction after April 7, 2026, compliance with one of these standards is the only option available. For the other two groups of wells, the option exists to routinely route to a control device that reduces methane and VOC emissions by at least 95.0 percent, provided that the owner or operator demonstrates and certifies that it is not technically feasible to comply with any of the options under §60.5377b(a)(1), (2), (3), or (4). See section 4.4.4 for a description of this compliance option. For wells that commence construction between May 7, 2024, and April 7, 2026, this route to control option is only available for the period between startup and April 7, 2026. After April 7, 2026, these wells must comply §60.5377b(a)(1), (2), (3), or (4). Figure 4-12 presents an overview of the initial and continuous compliance requirements for associated gas wells complying with §60.5377b(a).

Figure 4-12. Initial and Continuous Compliance Requirements for Associated Gas Wells Complying With §60.5377b(a)



Note that associated gas wells complying with §60.5377b(a) are allowed to temporarily route to a control device and to vent under limited circumstances. These allowances, as well as the associated compliance requirements, are discussed below in sections 4.4.2 and 4.4.3.

4.4.2 How Do I Comply with the Allowance to Temporary Route the Associated Gas to a Control Device?

The rule recognizes that there are situations when the beneficial use that is being utilized in accordance with §60.5377b(a)(1), (2), (3), or (4) may not be available. Therefore, the rule allows the associated gas to be temporarily routed to a control device that reduces methane and VOC emissions by at least 95.0 percent under four specific circumstances. Table 4-2 (Situations When Temporary Routing Associated Gas to a Control Device is Allowed [§60.5377b(d)]) identifies these circumstances and the duration for which routing to a control device is allowed.

Table 4-2. Situations When Temporary Routing Associated Gas to a Control Device is Allowed [§60.5377b(d)]

Associated Gas Wells Complying by . . .	Can Route to a Control Device . . .	For. . .
Scenario One. Routing the recovered gas into a gas gathering flow line or collection system to a sales line. [§60.5377b(a)(1)]	During a temporary interruption in service from the gathering or pipeline system.	Up to 30 days per incident
Scenario Two. Routing the recovered gas into a gas gathering flow line or collection system to a sales. [§60.5377b(a)(1)]	During periods when the composition of the associated gas does not meet pipeline specifications.	Up to 72 hours per incident
Using the recovered gas as an onsite fuel source. [§60.5377b(a)(2)]	During periods when the composition of the associated gas does not meet the quality requirements for use as a fuel.	Up to 72 hours per incident
Using the recovered gas for another useful purpose that a purchased fuel or raw material would serve. [§60.5377b(a)(3)]	During periods when the composition of the associated gas does not meet the quality requirements for another useful purpose.	Up to 72 hours per incident
Routing the recovered gas into a gas gathering flow line or collection system to a sales line [§60.5377b(a)(1)], using the recovered gas as an onsite fuel source [§60.5377b(a)(2)], using the recovered gas for another useful purpose that a purchased fuel or raw material would serve [§60.5377b(a)(3)], and reinjecting the recovered gas into the well or injecting the recovered gas into another well. [§60.5377b(a)(4)]	During a malfunction or incident that endangers the safety of operator personnel or the public, and during repair, maintenance (including blow downs), a production test, or commissioning.	Up to 24 hours or less per episode

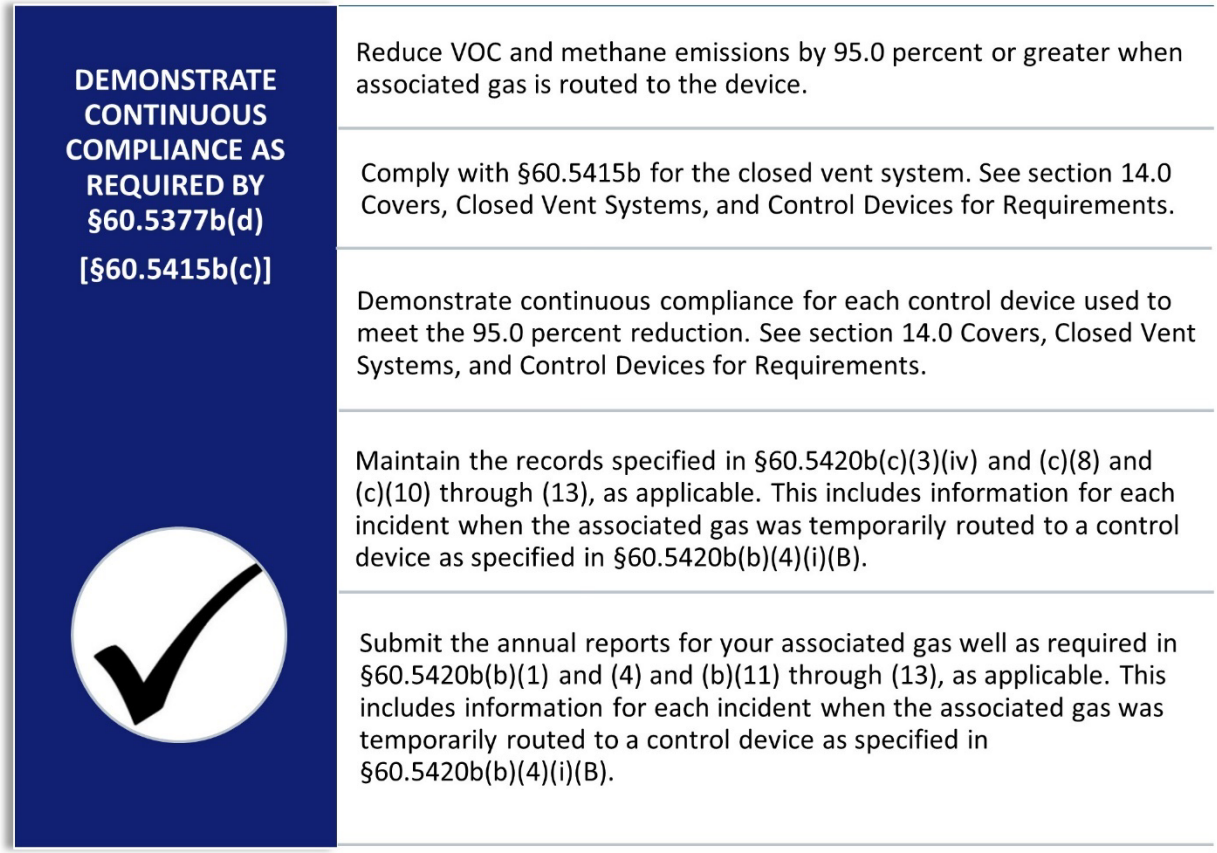
The associated gas must be routed through a CVS that meets the requirements of §60.5411b(a) and (c) and the control device must meet the conditions specified in §60.5412b during the period when the associated gas is routed to the device. See section 14 for the requirements for CVSs and control devices. Figure 4-13 presents an overview of the initial compliance requirements for associated gas wells temporarily routing emission to a control device and complying with §60.5377b(d). Figure 4-14 presents an overview of the continuous

compliance requirements for associated gas wells temporarily routing emission to a control device and complying with §60.5377b(d).

Figure 4-13. Initial Compliance Requirements for Associated Gas Wells Temporarily Routing Emissions to a Control Device Complying With §60.5377b(d)

DEMONSTRATE INITIAL COMPLIANCE AS REQUIRED BY §60.5377b(d) [§60.5410b(c)(3)] 	Reduce VOC and methane emissions by 95.0 percent or greater and as demonstrated by the requirements in §60.5413b during periods when the associated gas is routed to the device.
	Install a closed vent system that meets the requirements of §60.5411b(a) and (c) to capture the associated gas and route the captured associated gas to a control device that meets the conditions specified in §60.5412b. See section 14.0 Covers, Closed Vent Systems, and Control Devices for Requirements.
	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 by the manufacturer. See section 14.0 Covers, Closed Vent Systems, and Control Devices for Requirements.
	Conduct initial inspections of the closed vent system and bypasses. See section 14.0 Covers, Closed Vent Systems, and Control Devices for Requirements.
	Install and operate a continuous parameter monitoring system. See section 14.0 Covers, Closed Vent Systems, and Control Devices for Requirements.
	Maintain the records specified in §60.5420b(c)(3)(iv) and (c)(8) and (c)(10) through (13), as applicable. This includes information for each incident when the associated gas was temporarily routed to a control device as specified in §60.5420b(b)(4)(i)(B).
	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. This includes information for each incident when the associated gas was temporarily routed to a control device as specified in §60.5420b(b)(4)(i)(B).

Figure 4-14. Continuous Compliance Requirements for Associated Gas Wells Temporarily Routing Emissions to a Control Device Complying With §60.5377b(d)



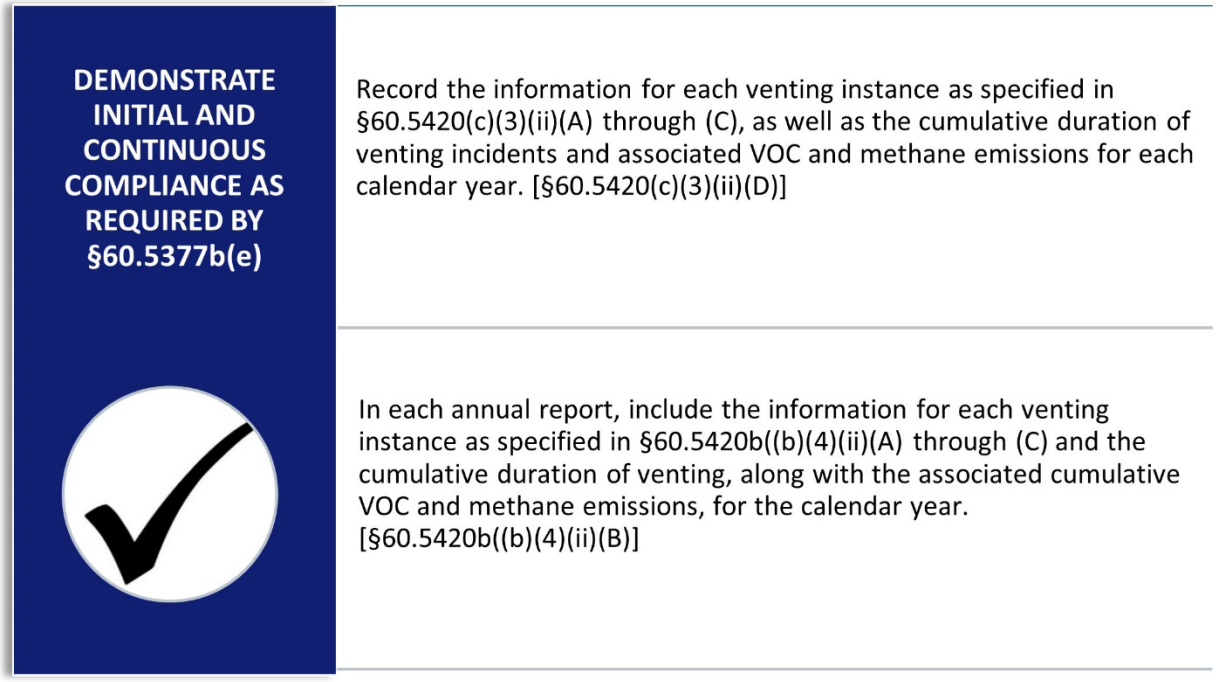
4.4.3 How Do I Comply with the Allowance to Temporary Vent Associated Gas?

The rule also allows associated gas to be vented for short periods in specified situations. [§60.5377b(e)] Specifically, the allowed venting durations and situations are:

- For up to 12 hours per incident to protect the safety of personnel.
- For up to 30 minutes per incident during bradenhead monitoring.
- For up to 30 minutes per incident during a packer leakage test.

The rule also includes a limit on the total duration of venting during a calendar year. Specifically, the cumulative period of venting must not exceed 24 hours in any calendar year. Figure 4-15 presents an overview of the initial and continuous compliance requirements for associated gas wells temporarily venting and complying with §60.5377b(e).

Figure 4-15. Initial and Continuous Compliance Requirements for Associated Gas Wells Temporarily Venting and Complying with §60.5377b(e)



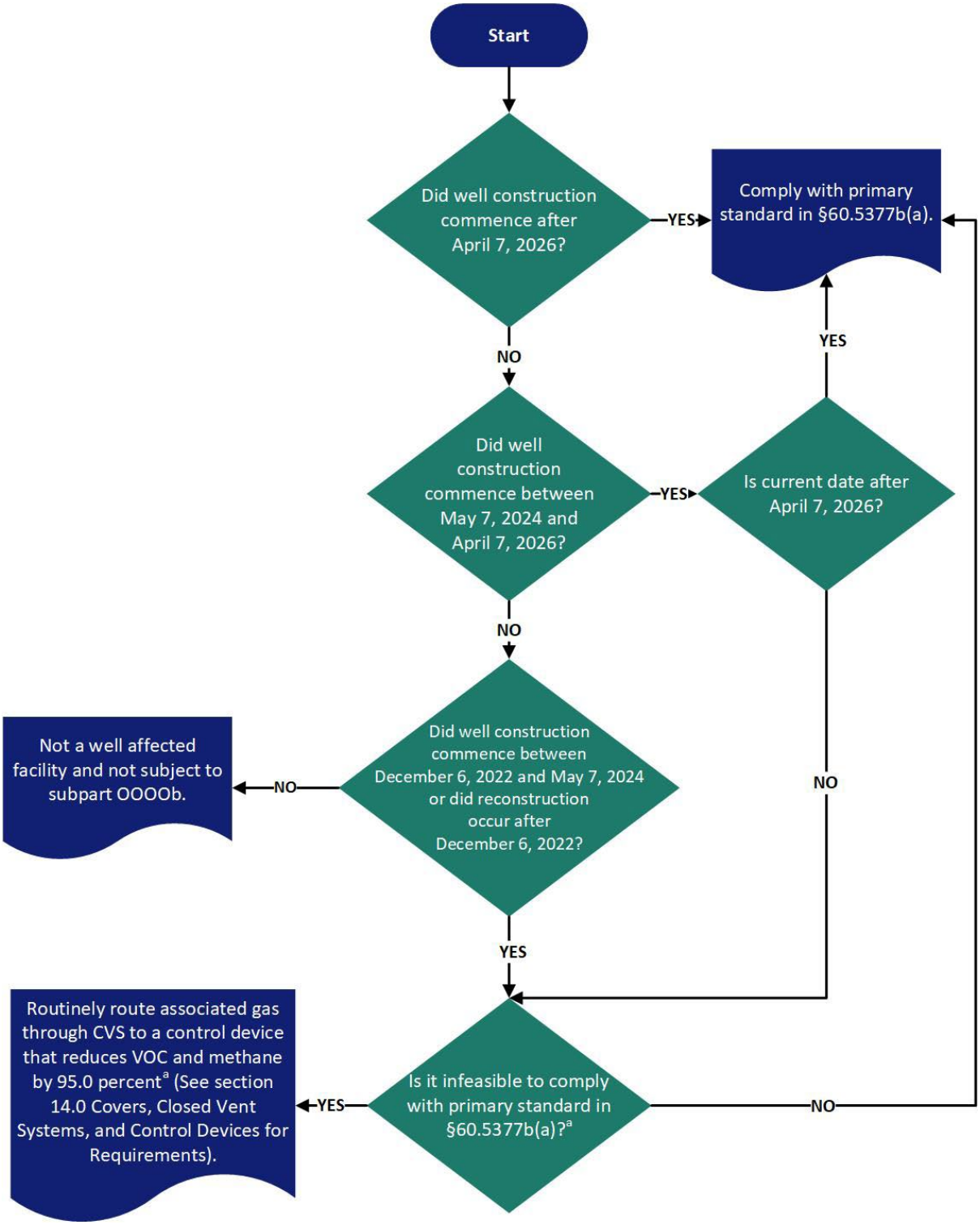
4.4.4 How Do I Comply with the Standard to Routinely Route Associated Gas to a Control Device?

Associated gas wells that commenced construction between December 6, 2022, and May 7, 2024, and wells that undergo reconstruction after December 6, 2022, are allowed to routinely route associated gas to a control device that reduces VOC and methane emissions by at least 95.0 percent provided that they demonstrate that it is technically infeasible to utilize any of the beneficial use methods included in §60.5377b(a)(1). This option is also available for wells that commence construction between May 7, 2024, and April 7, 2026. However, after April 7, 2026, these wells must comply with one of the standards in §60.5377b(a)(1).

The infeasibility demonstration must show that it is not feasible to comply with any of the standards specified in §60.5377b(a)(1), (2), (3), or (4) and the demonstration must be certified by a professional engineer or another individual with expertise in the uses of associated gas. This demonstration and certification must be re-evaluated annually. [§60.5377b(g)]

Figure 4-16 provides a depiction of the basics of the standard to routinely route the associated gas to a flare or control device. Figure 4-17 presents the initial compliance requirements for associated gas wells routinely routing emissions to a control device complying with §60.5377b(f), and Figure 4-18 presents the continuous compliance requirements for associated gas wells routinely routing emissions to a control device complying with §60.5377b(f).

Figure 4-16. Depiction of the Basics of the Standard to Routinely Route the Associated Gas to a Flare or Control Device Achieving 95.0 Percent Reduction in VOC and Methane

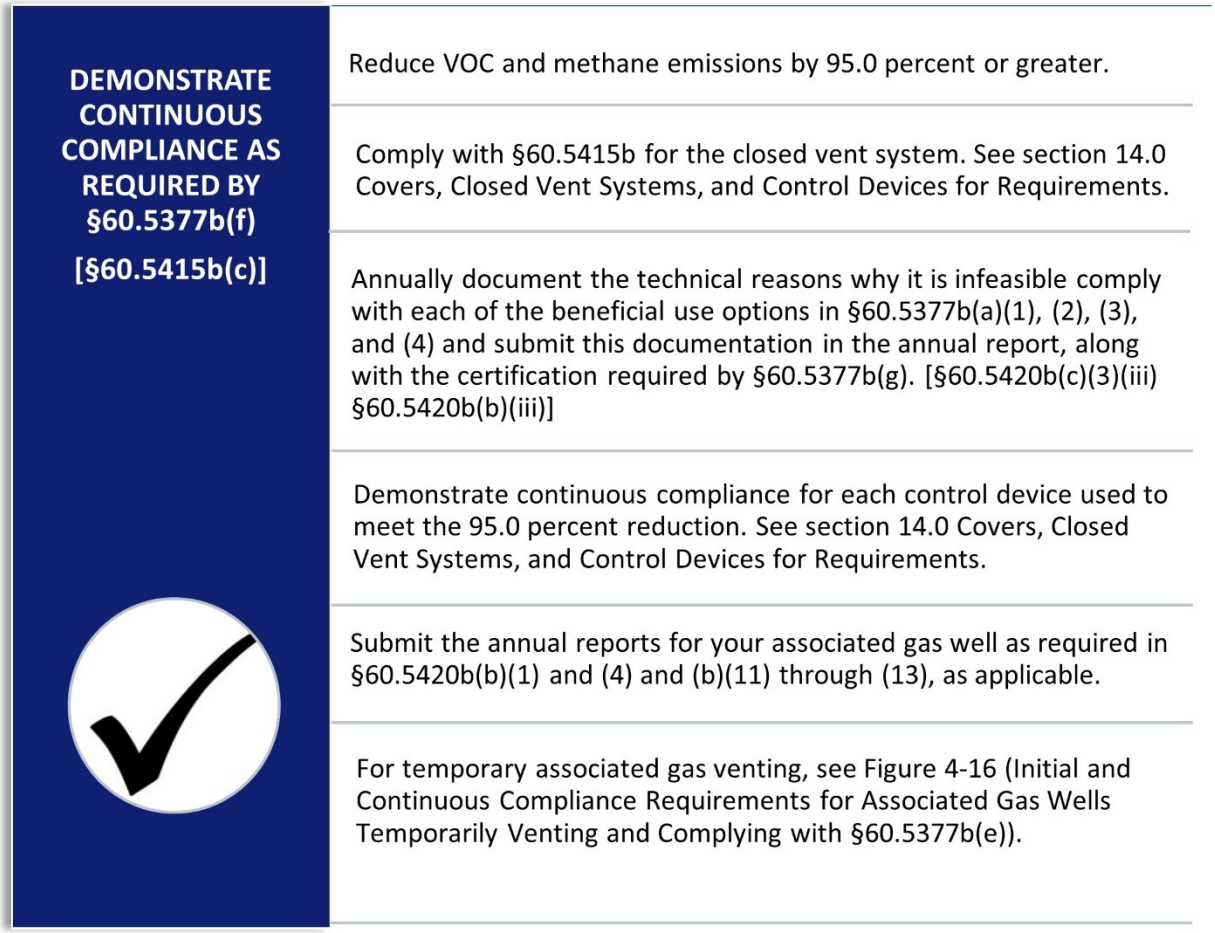


a. An infeasibility determination and certification must be performed initially and annually thereafter. Therefore, the allowance to routinely route associated gas is on a year-to-year basis.

Figure 4-17. Initial Compliance Requirements for Associated Gas Wells Routinely Routing Emissions to a Control Device Complying with §60.5377b(f) [§60.5410b(c)(2) and (3)]

DEMONSTRATE INITIAL COMPLIANCE AS REQUIRED BY §60.5377b(f) [§60.5410b(c)(2) and (3)] 	Document the technical reasons why it is infeasible comply with each of the beneficial use options in §60.5377b(a)(1), (2), (3), and (4) and submit this documentation in the initial annual report, along with the certification required by §60.5377b(g). [§60.5420b(c)(3)(iii) §60.5420b(b)(iii)]
	Reduce VOC and methane emissions by 95.0 percent or greater and as demonstrated by the requirements in §60.5413b during periods when the associated gas is routed to the device.
	Install a closed vent system that meets the requirements of §60.5411b(a) and (c) to capture the associated gas and route the captured associated gas to a control device that meets the conditions specified in §60.5412b. See section 14.0 Covers, Closed Vent Systems, and Control Devices for Requirements.
	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 by the manufacturer. See section 14.0 Covers, Closed Vent Systems, and Control Devices for Requirements.
	Conduct initial inspections of the closed vent system and bypasses. See section 14.0 Covers, Closed Vent Systems, and Control Devices for Requirements.
	Install and operate a continuous parameter monitoring system. See section 14.0 Covers, Closed Vent Systems, and Control Devices for Requirements.
	For temporary associated gas venting, see Figure 4-15 (Initial and Continuous Compliance Requirements for Associated Gas Wells Temporarily Venting and Complying with §60.5377b(e)).

Figure 4-18. Continuous Compliance Requirements for Associated Gas Wells Routinely Routing Emissions to a Control Device Complying With §60.5377b(f)



Associated gas wells that are complying with the standard in §60.5377b(f) to routinely route the associated gas to a control device that reduces VOC and methane emissions by 95.0 percent are allowed to temporarily vent the associated gas in specified situations provided in §60.5377b(e). Section 4.4.3 above provides these situations and summarizes the related compliance requirements.

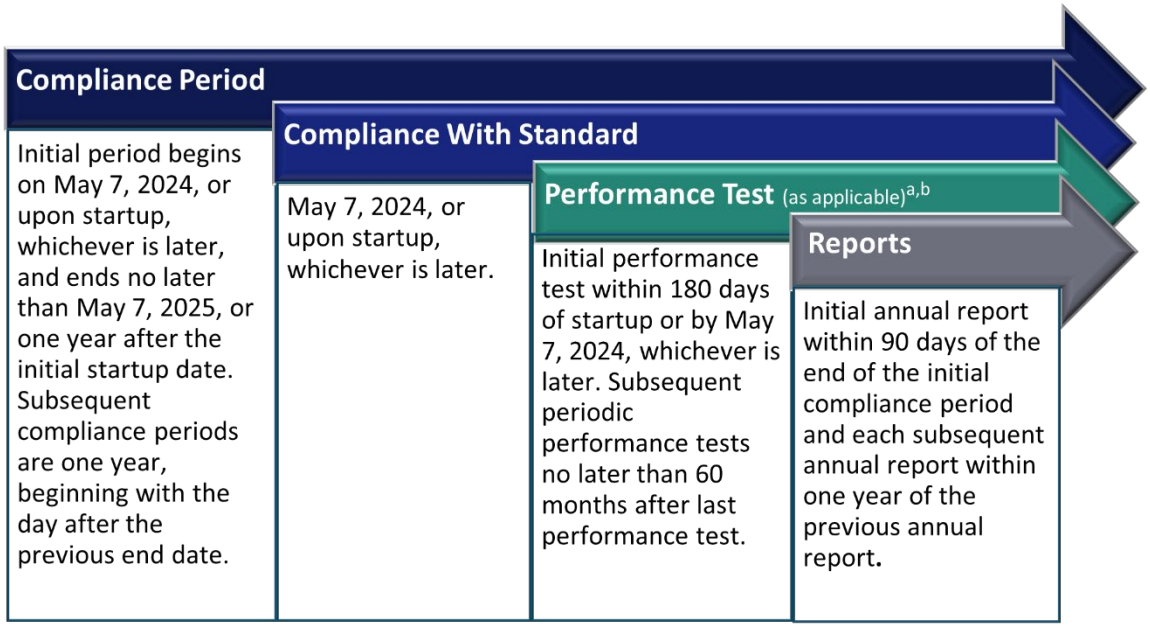
4.4.5 When must I comply?

You must be in compliance no later than May 7, 2024, or upon initial startup, whichever is later. [§60.5370b(a)] The initial compliance period begins on May 7, 2024, or upon initial startup, whichever is later, and ends no later than one year after the initial startup date or no later than May 7, 2025. [§60.5410b introductory text] You must submit your initial annual report within 90 days of the end of the initial compliance period, as described above, and submit each subsequent annual report within one year of the previous annual report.

[§60.5420b(b)] You must conduct an initial performance test within 180 days or by May 7, 2024, whichever is later. [§60.5413b(b)(5)]

Figure 4-19 (Compliance Schedule for Associated Gas Wells – Routing Emissions to a Control Device) provides a summary overview of the compliance schedule for associated gas wells routing emissions to a control device.

Figure 4-19. Compliance Schedule for Associated Gas Wells – Routing Emissions to a Control Device



a. A performance test is required for associated gas wells that are complying by routinely routing the associated gas to a control device in accordance with §60.5377b(f) and for associated gas wells that temporarily route associated gas to a control device in accordance with §60.5377b(d). No performance test is required for associated gas wells complying with §60.5377b(a) that do not temporarily route associated gas to a control device.
b. Enclosed combustion devices that are tested by the manufacturer according to the requirements of §60.5413b(d) and that are listed on the EPA website at www.epa.gov/airquality/oilandgas are not subject to the initial performance test requirements.

4.4.6 What testing or monitoring is required?

If you comply with §60.5377b(d) by temporarily routing emissions from your associated gas well through a CVS to a control device, or with §60.5377b(f) by routinely routing emissions from your associated gas well through a CVS to a control device, you must meet the requirements in section 14.0 (Covers, Closed Vent Systems, and Control Devices) of this document.

4.4.7 What, when, and to whom must I report?

In addition to the information outlined in section 1.4.3 above, you must include the information outlined in §60.5420b(b)(3) in your initial and subsequent annual reports. If you use a CVS and control device to comply with the standards, you also must submit the applicable information in §60.5420b(b)(11) through (13).

4.4.8 What records must I keep?

You must maintain records for each associated gas well. Specifically, you must maintain the records outlined in §60.5420b(c)(2), as applicable. In addition, if you use a CVS and control device to comply with the standards, you must maintain the records in §60.5420b(c)(8) and (10) through (13), as applicable.

5.0 GHG and VOC Standards for Centrifugal Compressor Affected Facilities

5.1 How do I determine if my centrifugal compressor is an affected facility?

If you own or operate a centrifugal compressor affected facility, which is a single centrifugal compressor, constructed, modified, or reconstructed after December 6, 2022, your centrifugal compressor is an affected facility. A centrifugal compressor located at a centralized production facility is an affected facility subject to rule requirements. [§60.5365b(b)]

A centrifugal compressor located at a well site is not an affected facility and not subject to requirements under the rule.

Definition

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.

5.2 How do I comply?

5.2.1 Wet Seal Compressors

To meet the standard for wet seal centrifugal compressors you must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent. [§60.5380b(a)(1)]

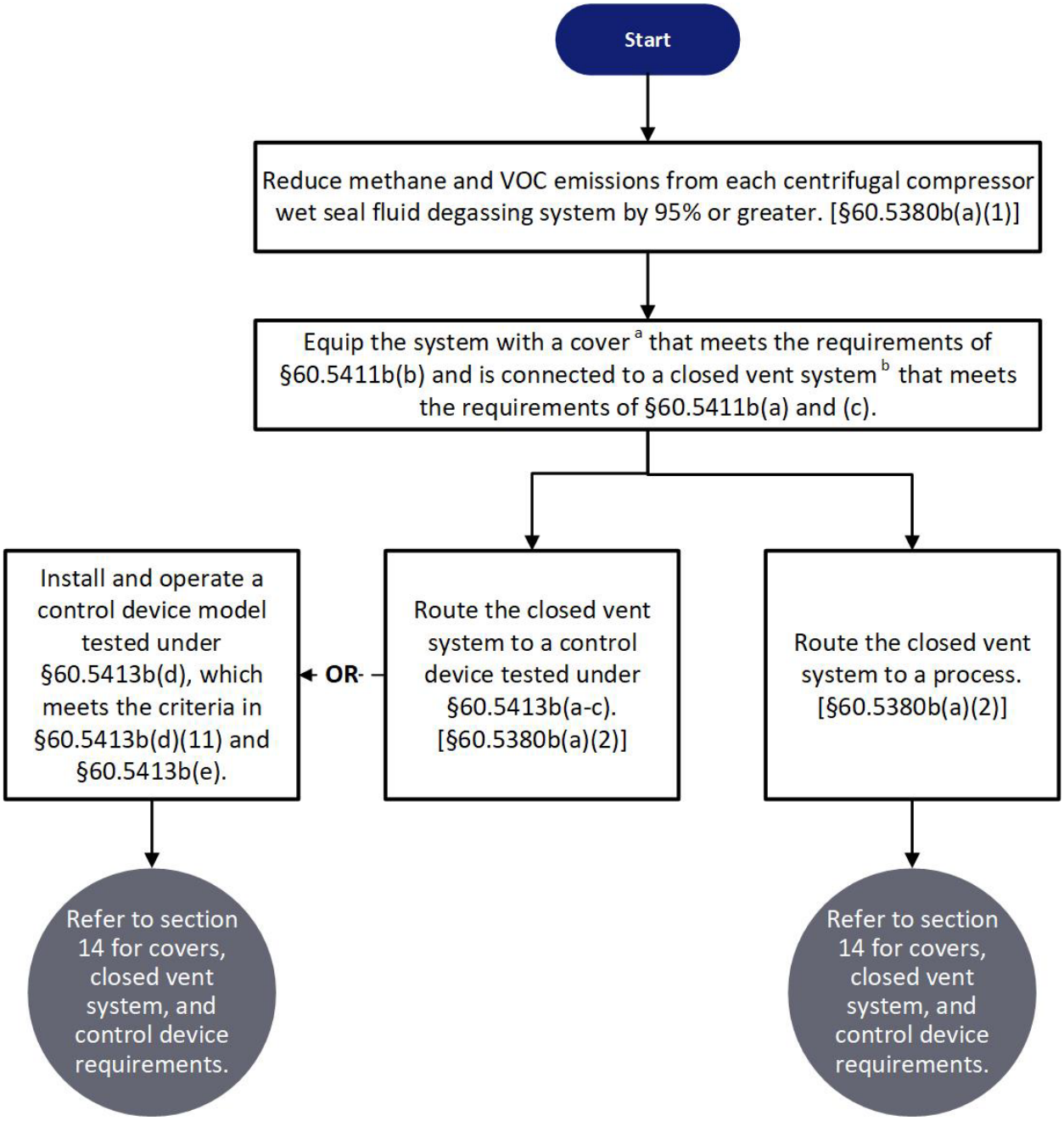
An operator may use a cover and CVS to route emissions to a control device or to a process. The rule includes requirements for cover, CVS and control devices that must be met to demonstrate the 95 percent emission reduction requirement. The rule does not have requirements for the process to which you may route the compressor emissions, however, the same CVS and cover requirements apply to this control scenario. These requirements include reporting and recordkeeping provisions.

For covers and CVS, you must meet specific requirements related to the design and installation of the covers and CVS, and initial and ongoing inspections, repair, and recordkeeping

requirements. For control devices, you must meet specified requirements for the design and installation of the control devices, initial performance testing, installation, and operation of a continuous parameter monitoring system (CPMS), and periodic performance testing and reporting and recordkeeping. An overview of these requirements is presented in section 14.0 (Covers, Closed Vent Systems, and Control Devices) of this guide.

Figure 5-1 (95 Percent Emission Reduction and Routing to a Process Requirements for Wet Seal Centrifugal Compressors) provides an overview of the 95 percent emission reduction and routing to process requirements for your centrifugal compressors.

Figure 5-1. 95 Percent Emission Reduction and Routing to a Process Requirements for Wet Seal Centrifugal Compressors



a. §60.5411b(b) cover requirements: (1) Form a continuous barrier over entire surface area of the liquid. (2) Secure each cover opening in a closed, sealed position, except when adding or removing material; conducting inspections, sampling, repairs, or maintenance; or venting to a CVS.

b. §60.5411b(a) CVS requirements: (1) Route all gases, vapors, and fume to a control device or to a process that meets the conditions specified in §60.5412b(a) through (c). (2) Design and operate with no detectable emissions per §60.5416b(b). (3) Meet the bypass requirements of §60.5411b(a)(3).

If you own or operate a self-contained wet seal centrifugal compressor (which includes wet seal compressors equipped with mechanical seals), or a centrifugal compressor equipped with a sour seal oil separator and capture system on the Alaska North Slope (ANS), you have the option of complying with the GHG and VOC requirements by monitoring and maintaining the volumetric flow rate per seal below or at a specified volumetric flow rate per seal, in lieu of meeting the 95 percent emission reduction and routing to a process requirements. To meet these requirements, you are required to determine the volumetric flow rate per seal, and you must repair or replace a seal to maintain flow rates at or below the specified flow rate. For self-contained wet seal centrifugal compressors, the specified volumetric flow rate is 3 standard cubic feet per minute (scfm) per seal. For centrifugal compressors on the ANS equipped with a sour seal oil separator and capture system, the specified volumetric flow rate is 9 scfm per seal.

Definitions

Self-contained wet seal centrifugal compressor means:

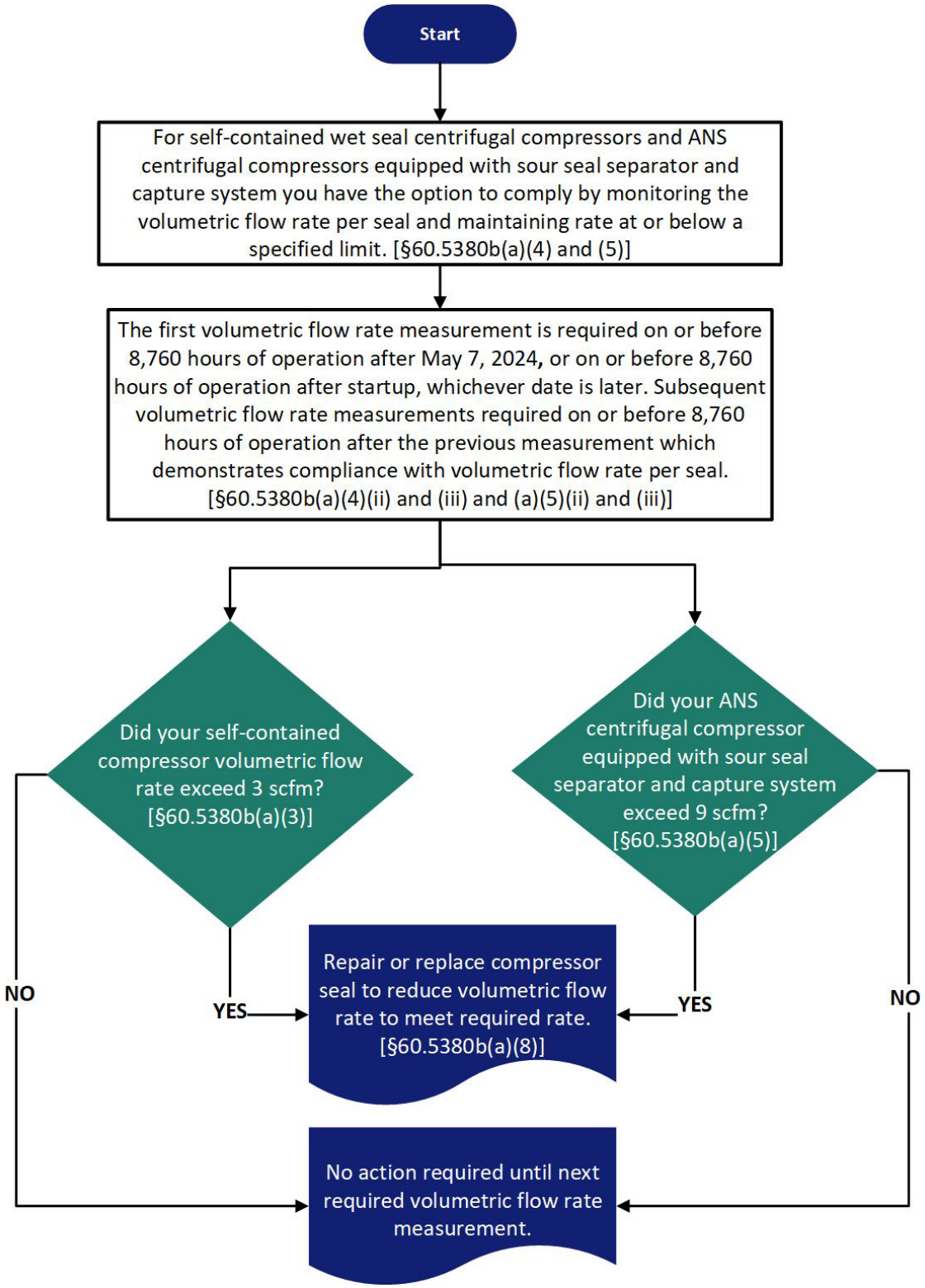
(1) A wet seal centrifugal compressor system that is a closed process that ports the degassing emissions into the natural gas line at the compressor suction (i.e., degassed emissions are recovered) or which has an intermediate closed process that degasses most of the gas entrained in the seal oil and 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 (1) a differential pressure is maintained on the system and there is no off gassing of the lube oil, and (3) the mechanical seal is integrated into the compressor housing.

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.

Figure 5-2 (Optional Compliance Requirements for Self-Contained Wet Seal Centrifugal Compressors and Centrifugal Compressors on the ANS Equipped with Sour Seal Oil Separator and Capture System) provides an overview of the alternative requirements for complying with the rule for self-contained wet seal centrifugal compressors and centrifugal compressors on the ANS equipped with a sour seal oil separator and capture system.

Figure 5-2. Optional Compliance Requirements for Self-Contained Wet Seal Centrifugal Compressors and Centrifugal Compressors on the ANS Equipped with Sour Seal Oil Separator and Capture System

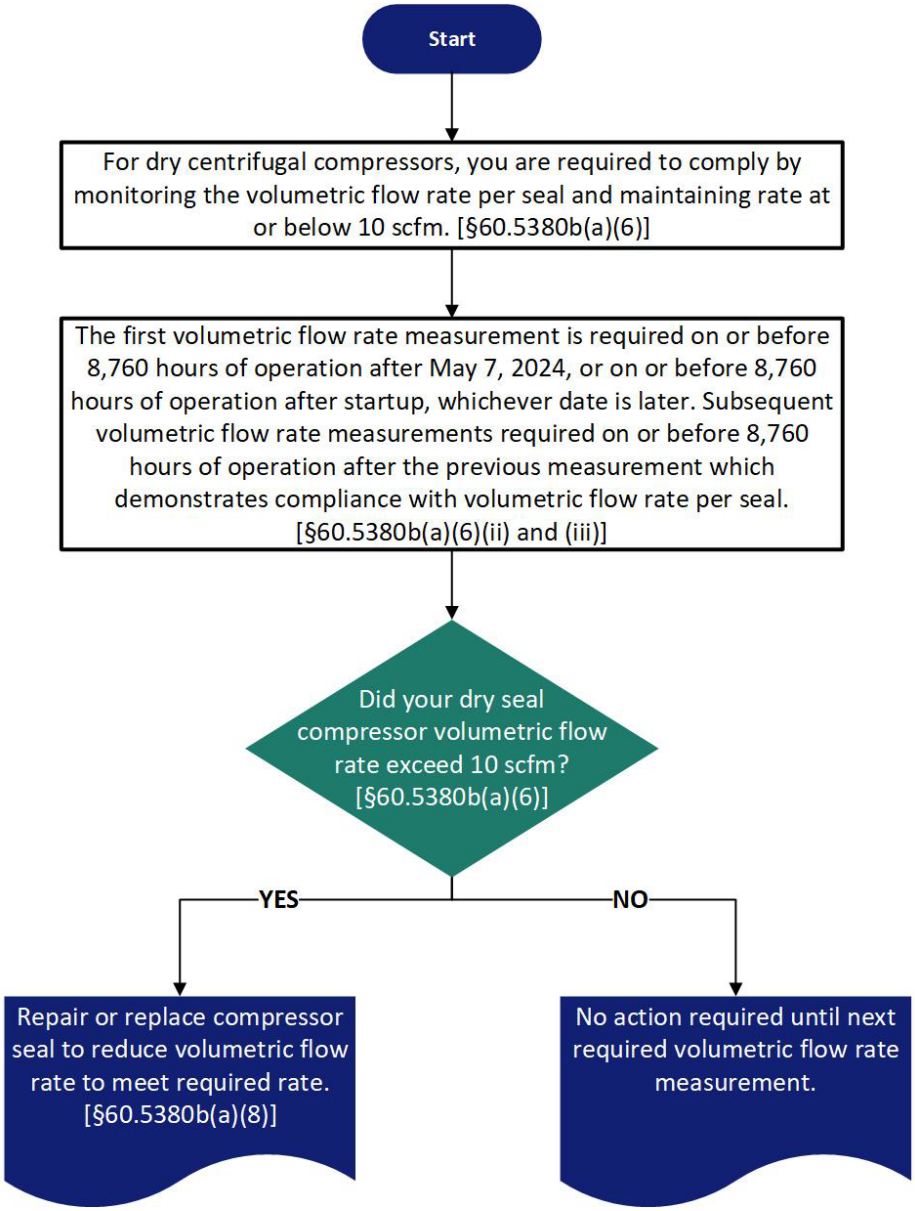


5.2.2 Dry Seal Compressors

To meet the standard for dry seal centrifugal compressors, you are required to comply with the GHG and VOC emission reduction requirements using volumetric flow rate as a surrogate. To meet these requirements, you are required to determine the volumetric flow rate per seal, and you must repair or replace the seal to maintain the volumetric flow rate below or at 10 scfm per seal.

Figure 5-3 (Dry Seal Centrifugal Compressor Requirements) provides an overview of the rule requirements for dry seal compressors.

Figure 5-3. Dry Seal Centrifugal Compressor Requirements



5.3 How do I demonstrate initial and continuous compliance?

Figure 5-4 (Initial Compliance Requirements for Wet Seal Centrifugal Compressors – Routing to a Control Device that Achieves 95 Percent Control) lists the requirements for demonstrating initial compliance for your wet seal centrifugal compressor affected facility complying by routing emissions to a control device that achieves 95 percent control, and Figure 5-5 (Initial Compliance Requirements for Wet Seal Centrifugal Compressors – Routing to a Process) lists the requirements for demonstrating initial compliance for your wet seal centrifugal compressor affected facility complying by routing emissions to a process. Figure 5-6 (Continuous Compliance Requirements for Wet Seal Centrifugal Compressors – Routing Emissions to a Process or to a Control Device that Achieves 95 Percent Control) lists the requirements for demonstrating continuous compliance for your wet seal centrifugal compressor affected facility complying by routing to a process or to a control device that achieves 95 percent control.

Figure 5-4. Initial Compliance Requirements for Wet Seal Centrifugal Compressors – Routing to a Control Device that Achieves 95 Percent Control

DEMONSTRATE INITIAL COMPLIANCE AS REQUIRED BY §60.5410b(d)	Reduce VOC and methane emissions by 95.0 percent or greater by routing to a process or installing a control device.
	Conduct an initial performance test within 180 days after initial startup or by May 7, 2024, whichever is later. Alternatively, you may install a control device tested by a manufacturer. See section 14.0 Covers, Closed Vent Systems, and Control Devices for requirements.
	Route all emissions through a closed vent system to a control device. See section 14.0 Covers, Closed Vent Systems, and Control Devices for requirements.
	Conduct initial inspections of the closed vent system and bypasses. See section 14.0 Covers, Closed Vent Systems, and Control Devices for requirements.
	Install and operate a continuous parameter monitoring system. See section 14.0 Covers, Closed Vent Systems, and Control Devices for requirements.
	Submit the initial annual report and other report(s) required by §60.5420b(b)(1), (5), and (b)(11) through (13), as applicable, and maintain the records as required by §60.5420b(c)(4), and (c)(8) through (13), as applicable.

Figure 5-5. Initial Compliance Requirements for Wet Seal Centrifugal Compressors – Routing to a Process

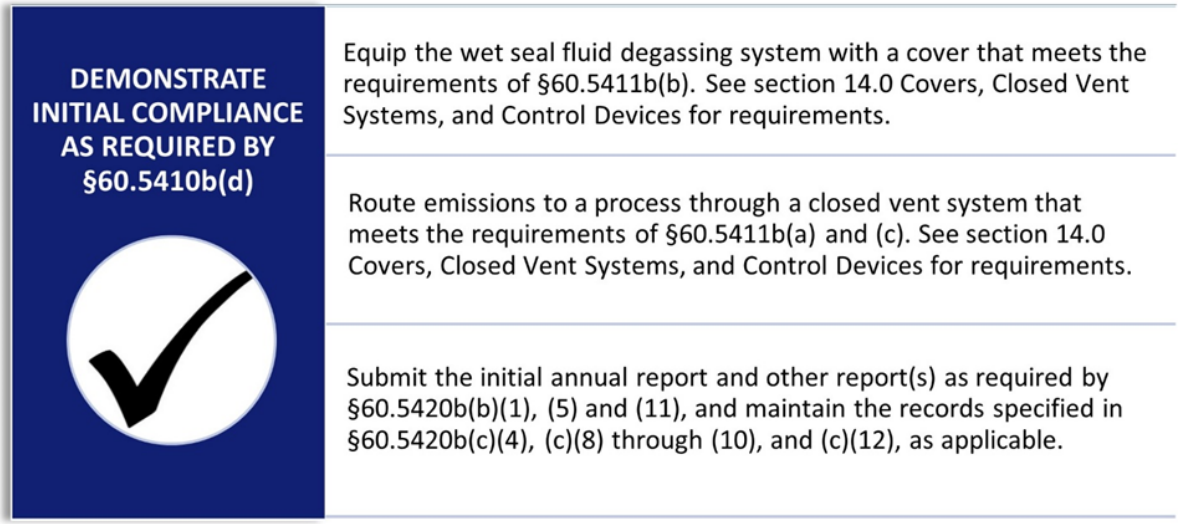
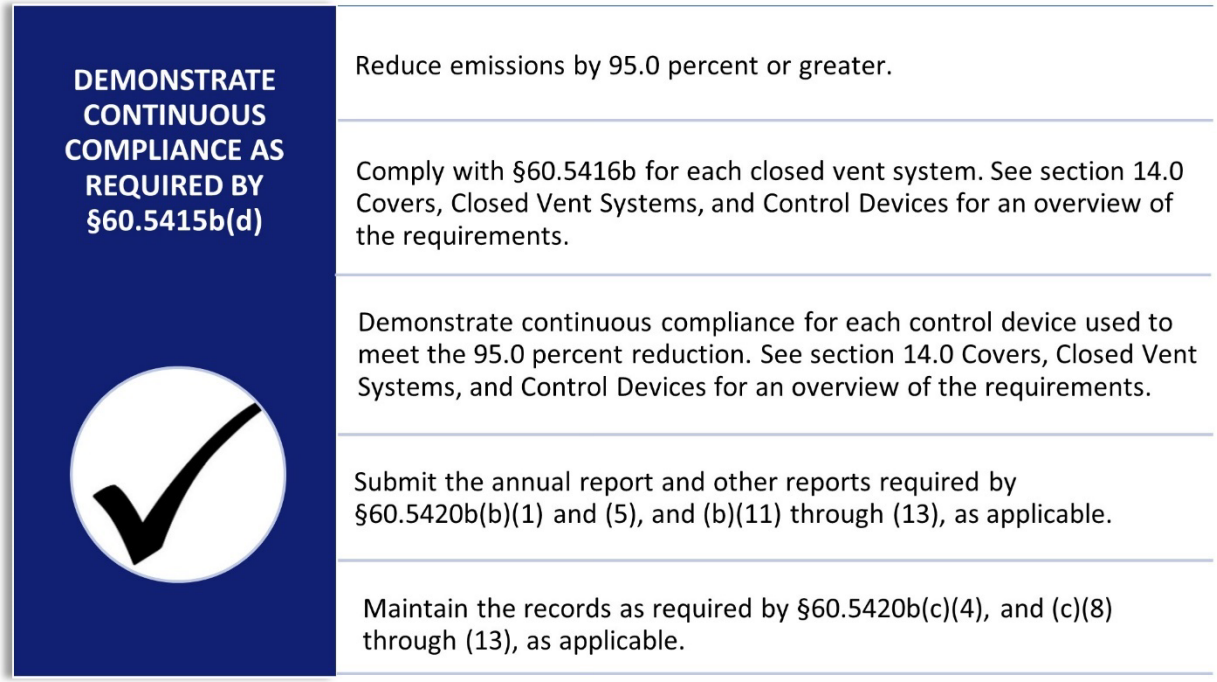


Figure 5-6. Continuous Compliance Requirements for Wet Seal Centrifugal Compressors – Routing Emissions to a Process or to a Control Device that Achieves 95 Percent Control



Figures 5-7 (Initial Compliance Requirements for Centrifugal Compressors – Volumetric Flow Rate Requirements) and 5-8 (Continuous Compliance Requirements for Centrifugal Compressors – Volumetric Flow Rate Requirements) list the requirements for demonstrating

initial and continuous compliance for your centrifugal compressor affected facilities (both wet seal and dry seal compressors) complying by meeting the volumetric flow rate requirements.

Figure 5-7. Initial Compliance Requirements for Centrifugal Compressors – Volumetric Flow Rate Requirements

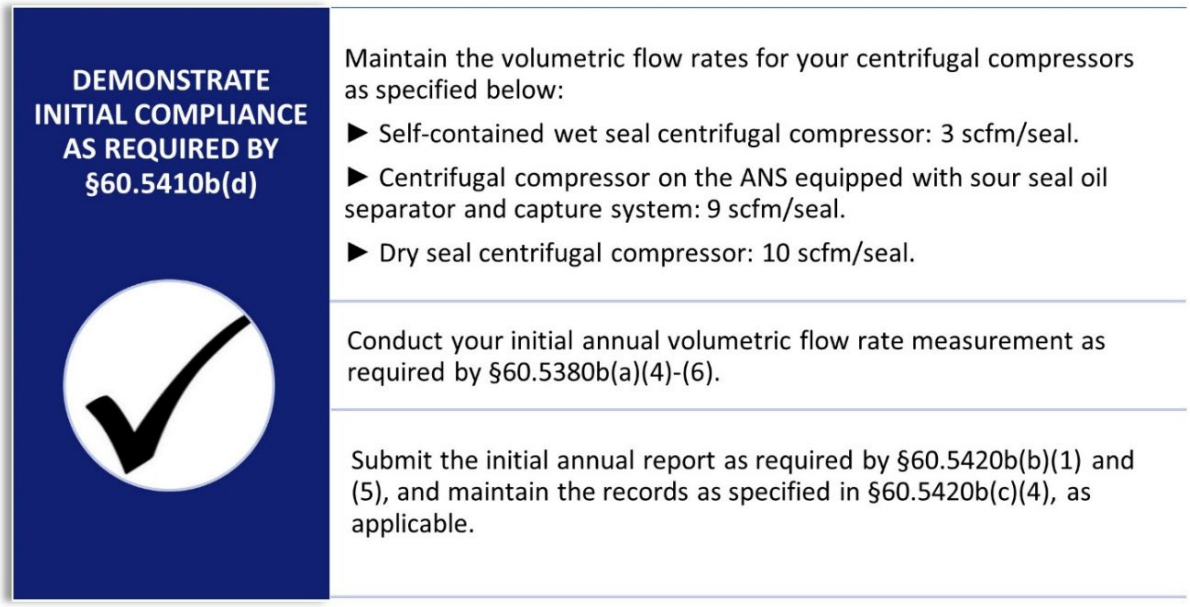
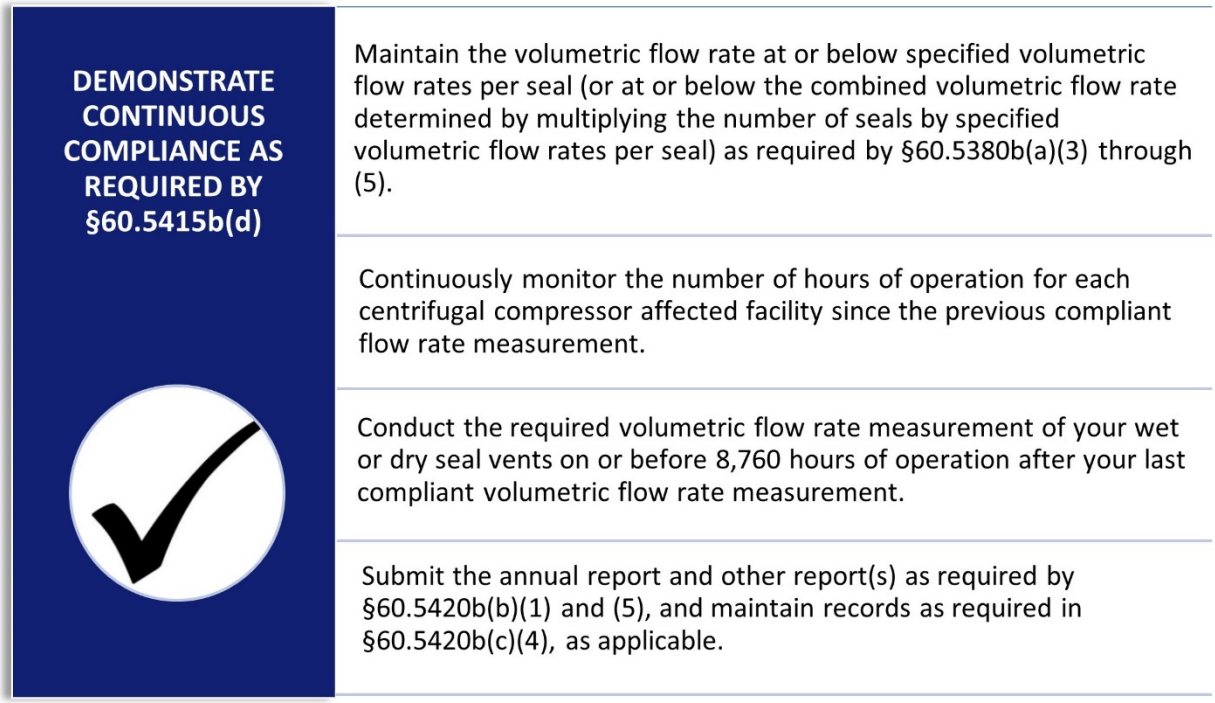


Figure 5-8. Continuous Compliance Requirements for Centrifugal Compressors – Volumetric Flow Rate Requirements



5.4 When must I comply?

5.4.1 95 Percent Emission Reduction and Routing to a Process Requirements for Centrifugal Compressors

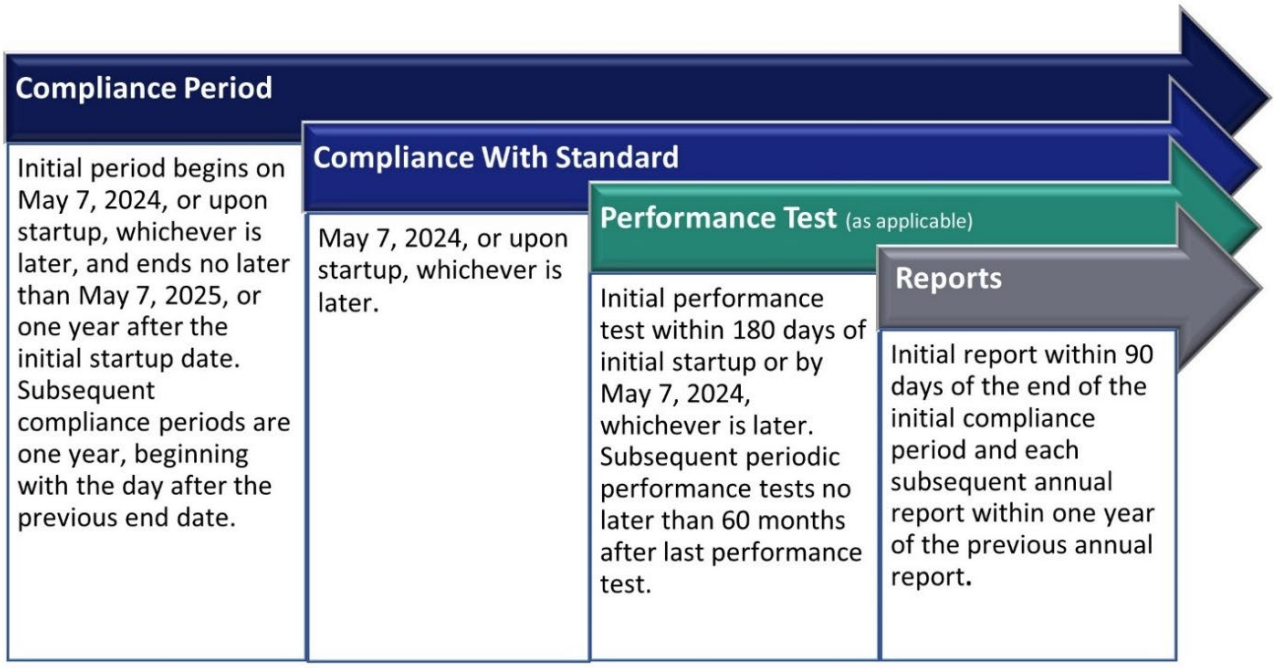
With the exception of performance testing for your control device, you must comply with all requirements for your centrifugal compressor by May 7, 2024, or upon startup, whichever is later.

You must also conduct a periodic performance test no later than 60 months after the initial performance test and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test. [§60.5413b(b)(5)(ii)]

You must submit your first annual report within 90 days after the end of the initial compliance period. The initial compliance period begins on May 7, 2024, or upon startup date of the affected facility, whichever is later, and ends no later than one year after the initial startup date for the affected facility or no later than May 7, 2025. [§60.5410b introductory text]

Figure 5-9 (Compliance Schedule for Centrifugal Compressors – Routing to a Process or Control Device that Achieves 95 Percent Control) provides a summary of the compliance schedule for your centrifugal compressor complying with the routing to a process or control device that achieves 95 percent requirements.

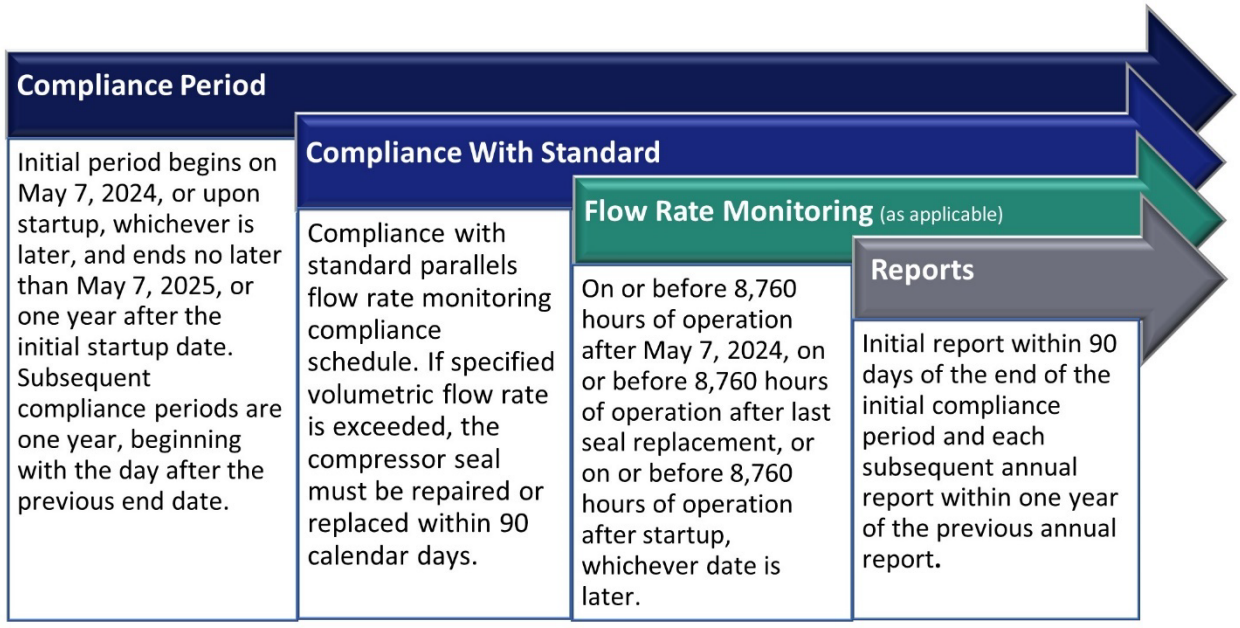
Figure 5-9. Compliance Schedule for Centrifugal Compressors – Routing to a Process or Control Device that Achieves 95 Percent Control



5.4.2 Centrifugal Compressor (Wet and Dry Seal) Volumetric Flow Rate Requirements

Figure 5-10 (Compliance Schedule for Centrifugal Compressors – Volumetric Flow Rate Requirements) provides a summary of the compliance schedule for your centrifugal compressor complying with the volumetric flow rate requirements.

Figure 5-10. Compliance Schedule for Centrifugal Compressors – Volumetric Flow Rate Requirements



5.5 What testing or monitoring is required?

If you comply by capturing and routing emissions from your centrifugal compressor through a CVS to a control device or to a process, you must meet the testing and monitoring requirements in section 14.0 (Covers, Closed Vent Systems, and Control Devices) of this guide.

Alternatively, if you comply by monitoring the volumetric flow rate from your centrifugal compressor and repairing or replacing seal to maintain the volumetric flow rate below or at a specific rate, you must meet the volumetric flow rate monitoring requirements specified in §60.5386b (What test methods and procedures must I use for my centrifugal compressor and reciprocating compressor affected facilities?). A high-level overview of what is required is provided in Figure 5-11 (Volumetric Flow Rate Measurement Requirements).

Figure 5-11. Volumetric Flow Rate Measurement Requirements

VOLUMETRIC FLOW RATE MEASUREMENT REQUIREMENTS §60.5386b	
	Screen for emissions or leaks using either optical gas imaging or EPA Method 21. If there is no indication of a leak, you can assume that the volumetric flow rate is 0 scfm and volumetric flow rate monitoring is not needed. If screening indicates a leak, you must monitor the volumetric flow rate (see below). [§60.5386b(a)(1) and (2)]
	Determine natural gas volumetric flow rate using a rate meter which meets the requirements in Method 2D in appendix A-1 of 40 CFR Part 60. [§60.5386b(b)]
	Use a high-volume sampler and meet the following [§60.5386b(c)]: ► Capture emissions from the applicable vent, measure the entire range of methane concentrations, and measure the total volumetric flow at standard conditions. [§60.5386b(c)(1)] ► Develop a standard operating procedure for the high-volume sampler device and document procedures in a monitoring plan. ► Include methane gas sensor(s) which meets specified requirements. [§60.5386b(c)(3)] ► Design sampler so that it is capable of sampling sufficient volume in order to capture all emissions from the applicable vent. [§60.5386b(c)(4)] ► Calibrate your methane gas sensor(s). [§60.5386b(c)(5)] ► Meet sampling procedure requirements. [§60.5386b(c)(6)] ► If measured natural gas flow exceeds 70.0 percent of the manufacturer's reported maximum sampling flow rate you must use either a temporary or permanent flow meter meeting specified requirements. [§60.5386b(c)(7)] ► As an alternative to a high-volume sampler, you may use any other method that is validated in accordance with Method 301 in appendix A in 40 CFR part 63. [§60.5386b(d)]

5.6 What, when and to whom must I report?

In addition to the information outlined in section 1.4.3 (Requirements applicable to all affected facilities) of this guide, you must include the information outlined in §60.5420b(b)(5) in your annual report for your centrifugal compressor affected facility.

5.7 What records must I keep?

If you comply by capturing and routing emissions from your centrifugal compressor through a CVS to a control device or to a process, you must maintain the records for each of your centrifugal compressors, and for any cover, CVS, control device or CPMS used to comply with the emission reduction requirements. Specifically, you must maintain the records outlined in §60.5420b(c)(4), and (c)(8) through (13), as applicable, for each centrifugal compressor, cover, CVS, or control device.

If you comply by maintaining the volumetric flow rate per seal for your wet seal self-contained centrifugal compressor, centrifugal compressors on the ANS equipped with sour seal oil separator and capture system, or dry seal compressor you must maintain the records outlined in §60.5420b(c)(4), as applicable.

6.0 GHG and VOC Standards for Reciprocating Compressor Affected Facilities

6.1 How do I determine if my reciprocating compressor is an affected facility?

A reciprocating compressor affected facility is each single reciprocating compressor for which construction, modification or reconstruction commenced after December 6, 2022. A reciprocating compressor located at a centralized production facility is an affected facility under the rule. [§60.5365b(c)]

A reciprocating compressor located at a well site is not an affected facility and not subject to requirements under the rule.

Definition

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

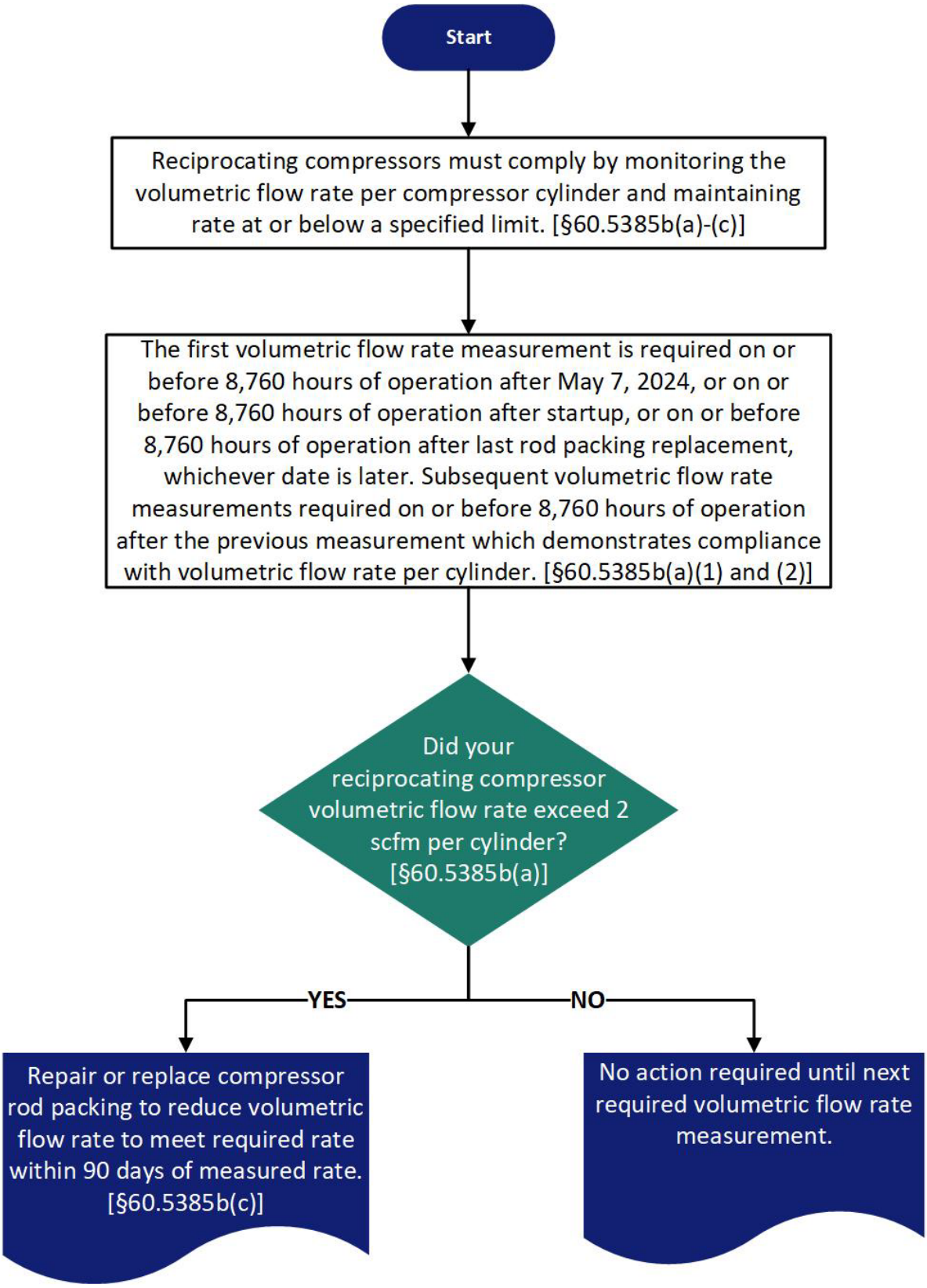
6.2 How do I comply?

To comply with the standard for reciprocating compressor affected facilities, you must replace or repair the reciprocating compressor rod packing if the measured volumetric flow rate per compressor cylinder exceeds 2 scfm per cylinder. Volumetric flow rate monitoring is required 8,760 hours of operation after a compliant flow rate measurement or new rod packing replacement. You are also allowed to comply with the rule by replacing the rod packing in lieu of conducting monitoring if it is done on or before 8,760 hours of operation since the last compliant flow rate measurement or new rod packing replacement. Figure 6-1 (Requirements for Reciprocating Compressors – Volumetric Flow Rate Monitoring) provides an overview of the requirements for your reciprocating compressor affected facility if you comply with the volumetric flow rate monitoring requirements.

Definition

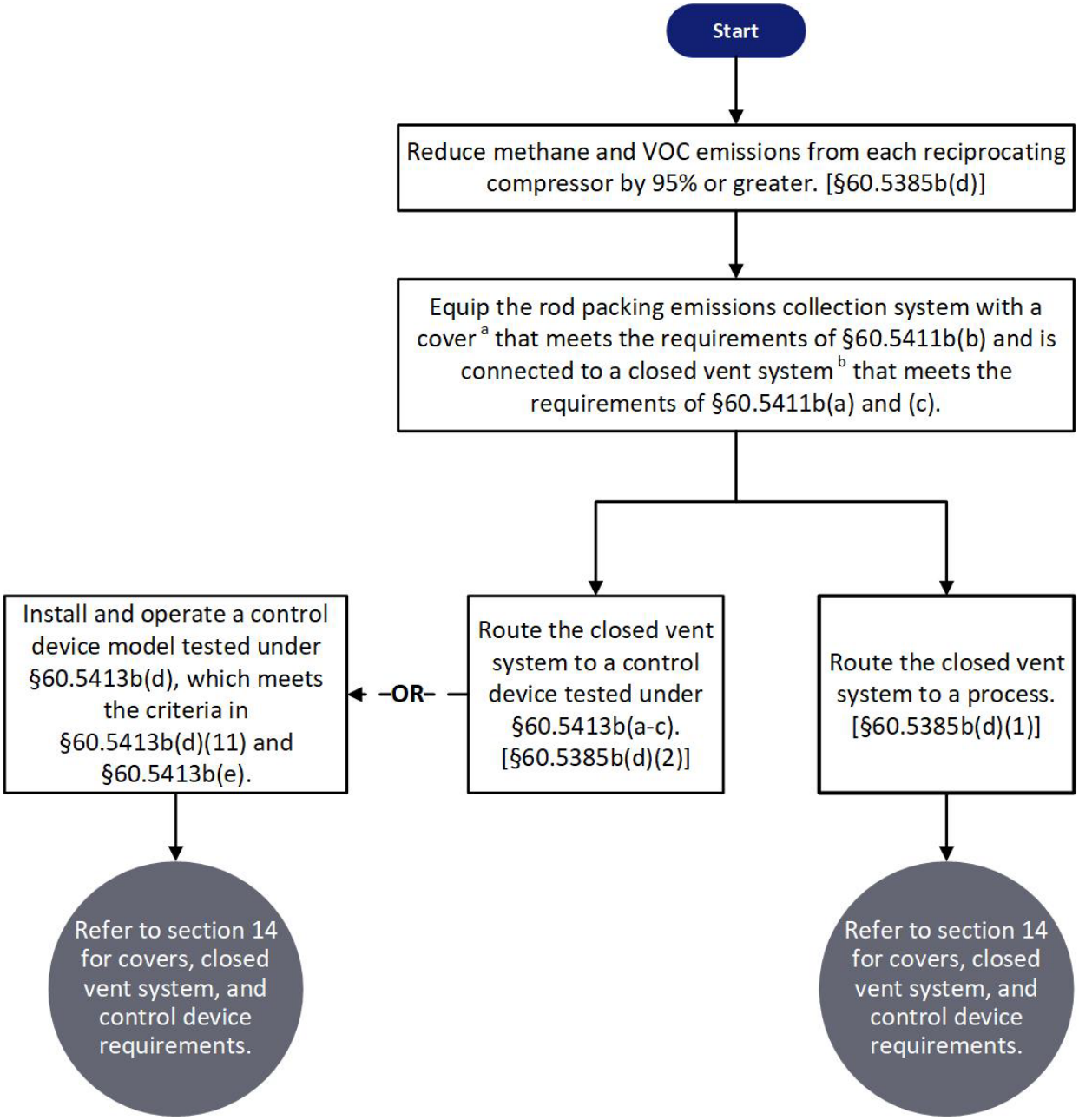
Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere, or other mechanism that provides the same function.

Figure 6-1. Requirements for Reciprocating Compressors – Volumetric Flow Rate Monitoring



Alternatively, you can also choose to comply with the standard by capturing the emissions and routing to a process or control device achieving 95 percent control using a rod packing emissions collection system. Figure 6-2 (95 Percent Emission Reduction and Routing to a Process Requirements for Reciprocating Compressors) provides an overview of these alternative requirements.

Figure 6-2. 95 Percent Emission Reduction and Routing to a Process Requirements for Reciprocating Compressors



a. §60.5411b(b) cover requirements: (1) Form a continuous barrier over entire surface area of the liquid. (2) Secure each cover opening in a closed, sealed position, except when adding or removing material; conducting inspections, sampling, repairs, or maintenance; or venting to a CVS.
b. §60.5411b(a) CVS requirements: (1) Route all gases, vapors, and fume to a control device or to a process that meets the conditions specified in §60.5412b(a) through (c). (2) Design and operate with no detectable emissions per §60.5416b(b). (3) Meet the bypass requirements of §60.5411b(a)(3).

6.3 How do I demonstrate initial and continuous compliance?

Figure 6-3 (Initial Compliance Requirements for Reciprocating Compressors – Volumetric Flow Rate Requirements) lists the requirements for demonstrating initial compliance and Figure 6-4 (Continuous Compliance Requirements for Reciprocating Compressors – Volumetric Flow Rate Requirements) lists the requirements for demonstrating continuous compliance for your reciprocating compressor affected facility complying with the volumetric flow rate requirements.

Figure 6-3. Initial Compliance Requirements for Reciprocating Compressors – Volumetric Flow Rate Requirements

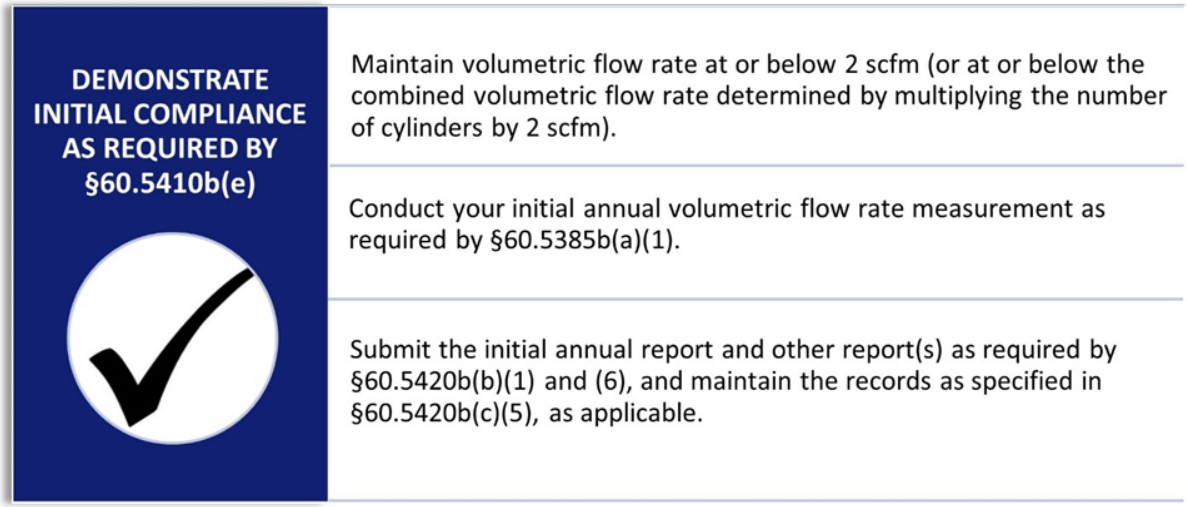


Figure 6-4. Continuous Compliance Requirements for Reciprocating Compressors – Volumetric Flow Rate Requirements

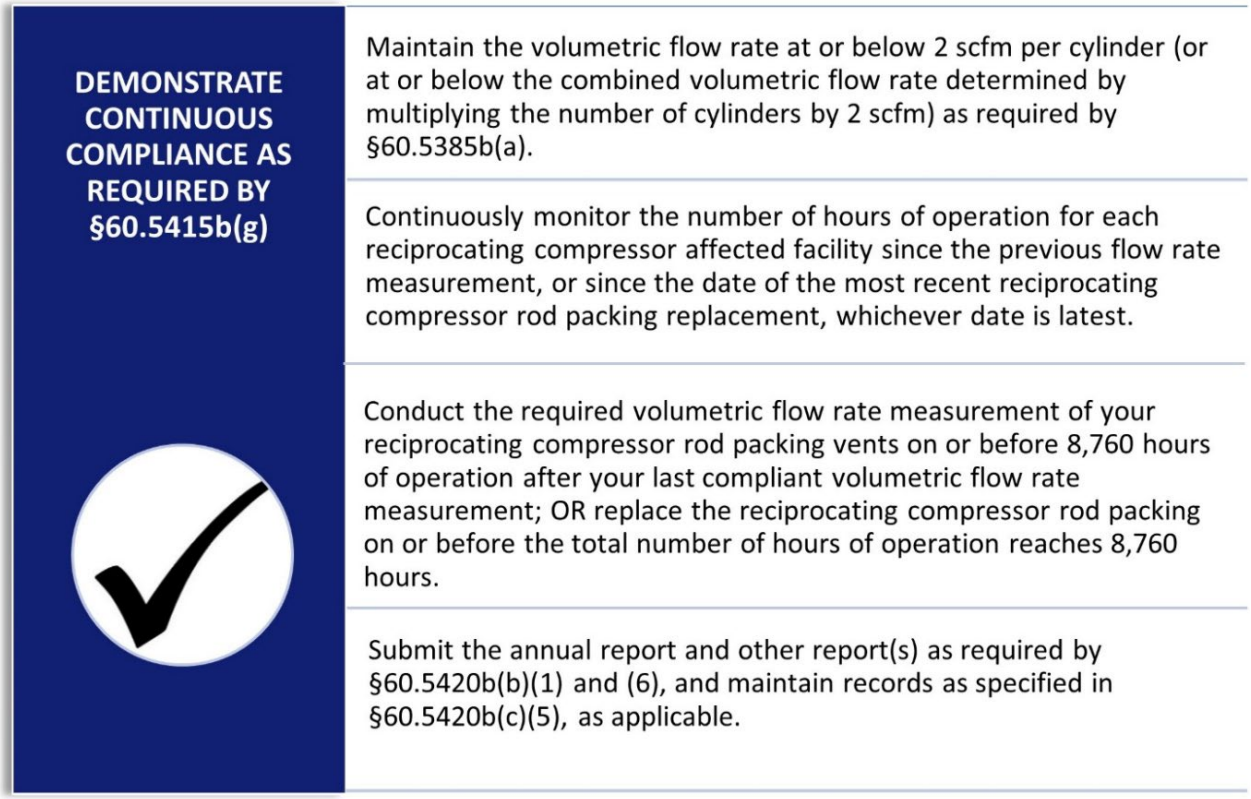


Figure 6-5 (Initial Compliance Requirements for Reciprocating Compressors – Routing to a Process) lists the requirements for demonstrating initial compliance for your reciprocating compressor affected facility complying with the routing to a process compliance option. Figure 6-6 (Initial Compliance Requirements for Reciprocating Compressors – Routing to a Control Device that Achieves 95 Percent Control) lists the requirements for demonstrating initial compliance for your reciprocating compressor affected facility complying with the alternative compliance option of routing to a control device that achieves 95 percent control. Figure 6-7 (Continuous Compliance Requirements for Reciprocating Compressors – Route Emissions to a Process or to a Control Device that Achieves 95 Percent Control) lists the requirements for demonstrating continuous compliance for your reciprocating compressor affected facility complying with the alternative compliance options of routing to a process or to a control device that achieves 95 percent control.

Figure 6-5. Initial Compliance Requirements for Reciprocating Compressors – Routing to a Process

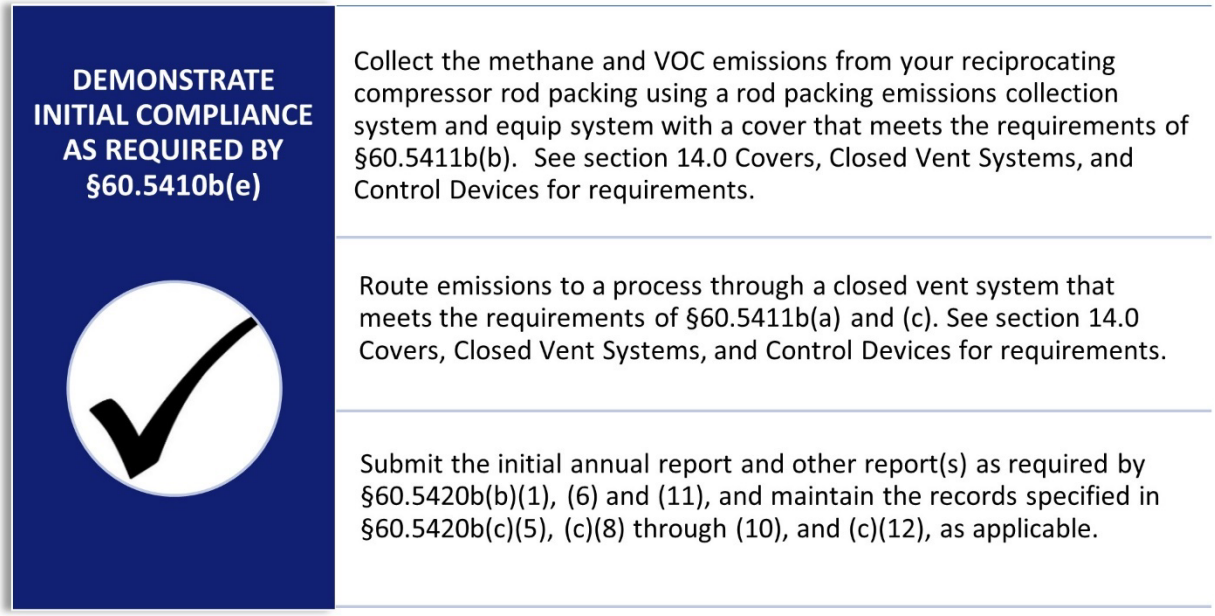
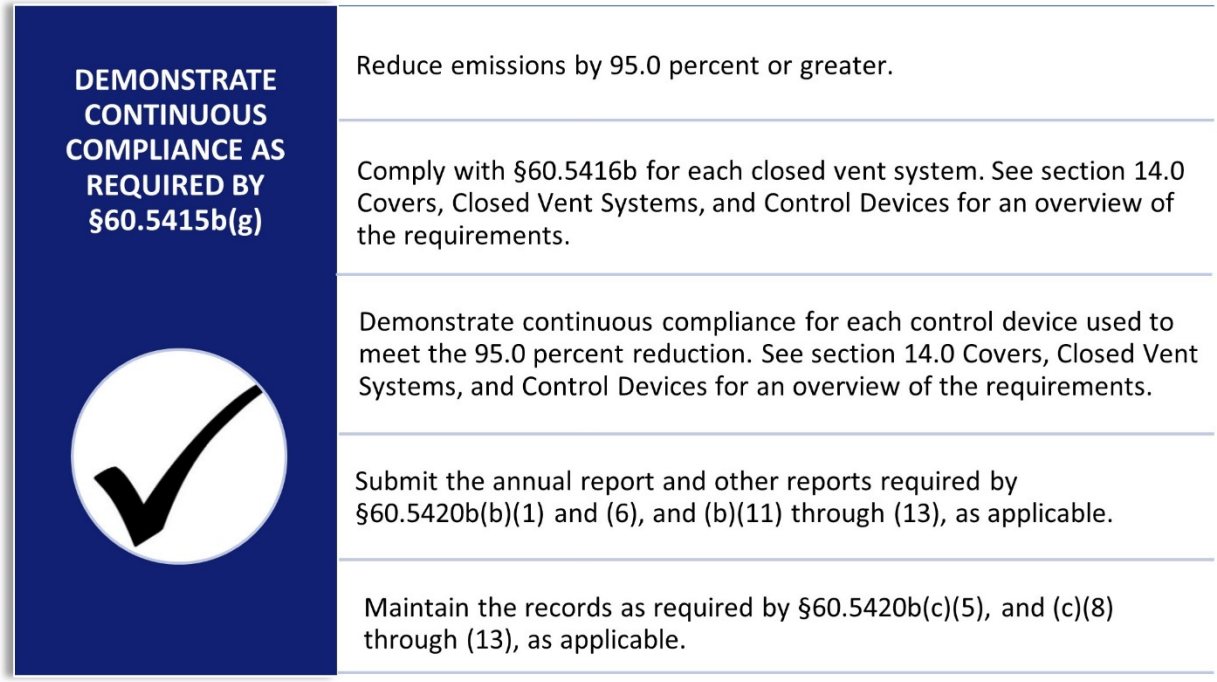


Figure 6-6. Initial Compliance Requirements for Reciprocating Compressors – Routing to a Control Device that Achieves 95 Percent Control

DEMONSTRATE INITIAL COMPLIANCE AS REQUIRED BY §60.5410b(e) 	Reduce VOC and methane emissions by 95.0 percent or greater by installing a control device.
	Conduct an initial performance test within 180 days after initial startup or by May 7, 2024, whichever is later. Alternatively, you may install a control device tested by a manufacturer. See section 14.0 Covers, Closed Vent Systems, and Control Devices for requirements.
	Route all emissions through a closed vent system to a control device. See section 14.0 Covers, Closed Vent Systems, and Control Devices for requirements.
	Conduct initial inspections of the closed vent system and bypasses. See section 14.0 Covers, Closed Vent Systems, and Control Devices for requirements.
	Install and operate a continuous parameter monitoring system. See section 14.0 Covers, Closed Vent Systems, and Control Devices for requirements.
	Submit the initial annual report and other report(s) required by §60.5420b(b)(1), (6), and (b)(11) through (13), and maintain the records as required by §60.5420b(c)(5), and (c)(8) through (13), as applicable.

Figure 6-7. Continuous Compliance Requirements for Reciprocating Compressors – Route Emissions to a Process or to a Control Device that Achieves 95 Percent Control



6.4 When must I comply?

You must comply with the standards by May 7, 2024, or upon startup of your reciprocating compressor, whichever is later. The initial compliance period begins on May 7, 2024, or upon startup date of an affected facility, whichever is later, and ends no later than one year after the initial startup date for the affected facility or no later than May 7, 2025. [§60.5410b introductory text]

You must submit your initial annual report within 90 days of the end of the initial compliance period, as described above and submit each subsequent annual report within one year of the previous annual report.

Figure 6-8 (Compliance Schedule for Reciprocating Compressors – Volumetric Flow Rate Requirements) provides a summary overview of the compliance schedule for your reciprocating compressor when complying with the volumetric flow rate monitoring requirements, and Figure 6-9 (Compliance Schedule for Reciprocating Compressors – Routing to Process or Control Device Requirements) provides a summary overview of the compliance schedule for your reciprocating compressor if complying by capturing emissions and routing to a process or control device.

Figure 6-8. Compliance Schedule for Reciprocating Compressors – Volumetric Flow Rate Requirements

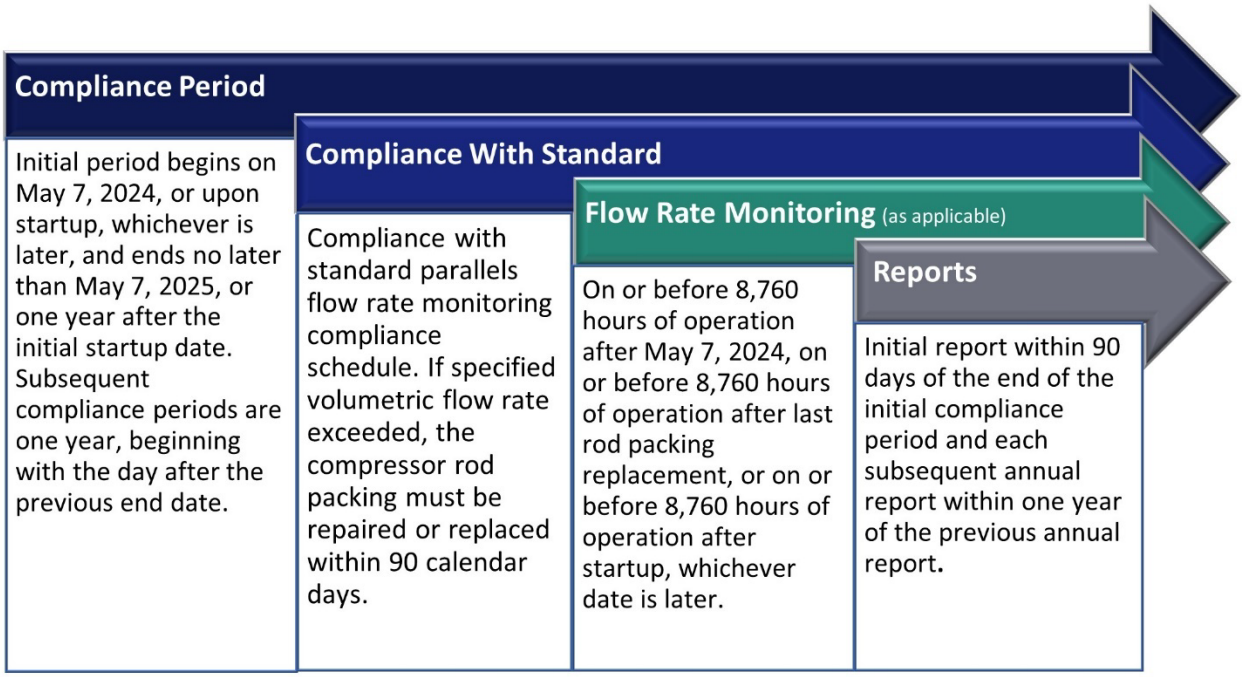
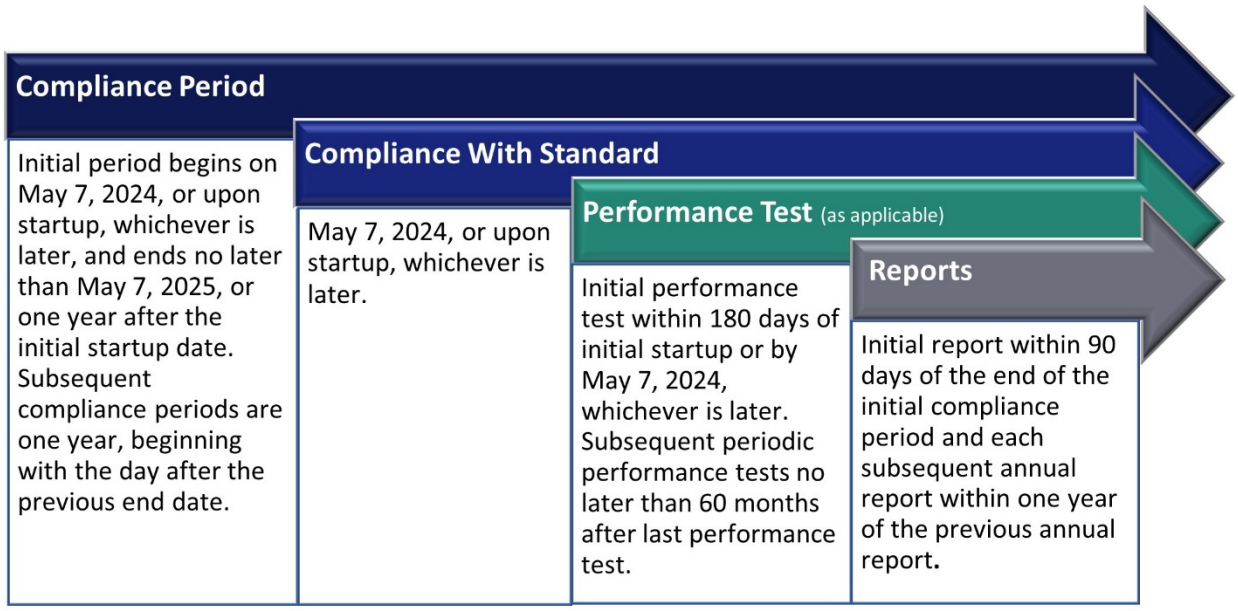


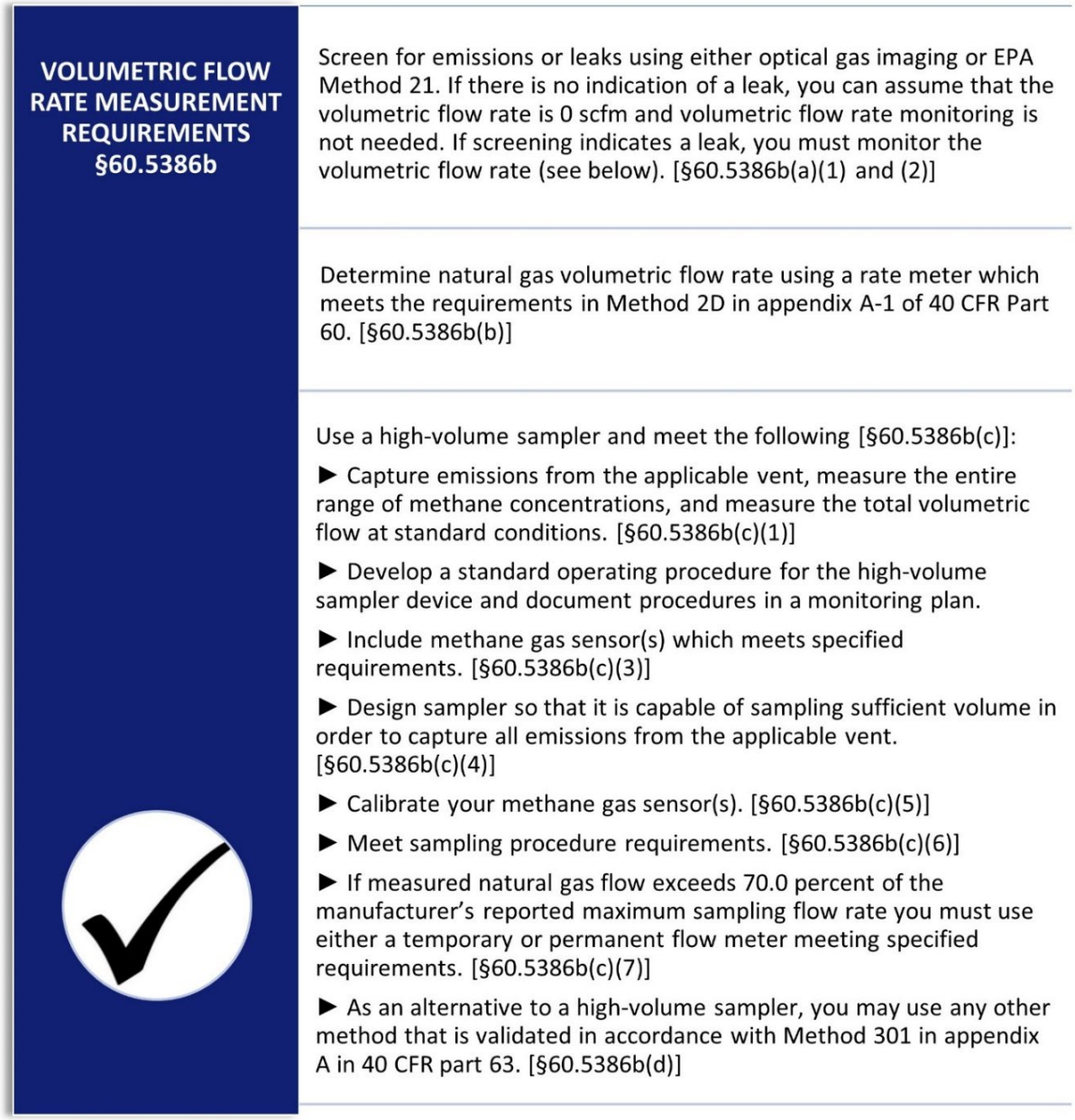
Figure 6-9. Compliance Schedule for Reciprocating Compressors – Routing to Process or Control Device Requirements



6.5 What testing or monitoring is required?

If you comply by monitoring the volumetric flow rate from your reciprocating compressor and repairing or replacing the rod packing to maintain the volumetric flow rate below or at a specific rate, you must meet the volumetric flow rate monitoring requirements specified in §60.5386b (What test methods and procedures must I use for my centrifugal compressor and reciprocating compressor affected facilities?). A high-level overview of what is required is provided in Figure 6-10 (Volumetric Flow Rate Measurement Requirements).

Figure 6-10. Volumetric Flow Rate Measurement Requirements



If you use a rod packing emissions collection system and a CVS to capture and route emissions to a process, you must meet the testing and monitoring requirements in section 14.0 (Covers, Closed Vent Systems, and Control Devices) of this guide.

6.6 What, when and to whom must I report?

In addition to the information outlined in section 1.4.3 (Requirements applicable to all affected facilities) of this guide, you must include the information outlined in §60.5420b(b)(6) of the rule in your annual report for your reciprocating compressor affected facility.

6.7 What records must I keep?

If you comply by maintaining the volumetric flow rate for your reciprocating compressor below 2 scfm, you must maintain the records outlined in §60.5420b(c)(5).

If you comply by capturing and routing emissions from your reciprocating compressor through a CVS to a control device or to a process, you must maintain records for each of your reciprocating compressors, and for any cover or CVS used to comply with the emission reduction requirements. Specifically, you must maintain the records outlined in §60.5420b(c)(5), and (c)(8) through (13), as applicable, for each reciprocating compressor, cover, CVS, or control device.

7.0 GHG and VOC Standards for Process Controller Affected Facilities

7.1 How do I determine if my process controller is an affected facility?

The rule applies to the collection of natural gas-driven process controllers constructed, modified, or reconstructed after December 6, 2022, as follows: [§60.5365b(d)]

- The affected facility is the collection of all natural gas-driven process controllers located at a well site, centralized production facility, onshore natural gas processing plant, or compressor station.
- Natural gas-driven process controllers that function as emergency shutdown devices are not part of the affected facility.
- Process controllers not driven by natural gas are not part of the affected facility.

Definitions

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.

Natural gas-driven process controller means a process controller powered by pressurized natural gas.

Process controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure, and temperature.

7.2 How do I comply?

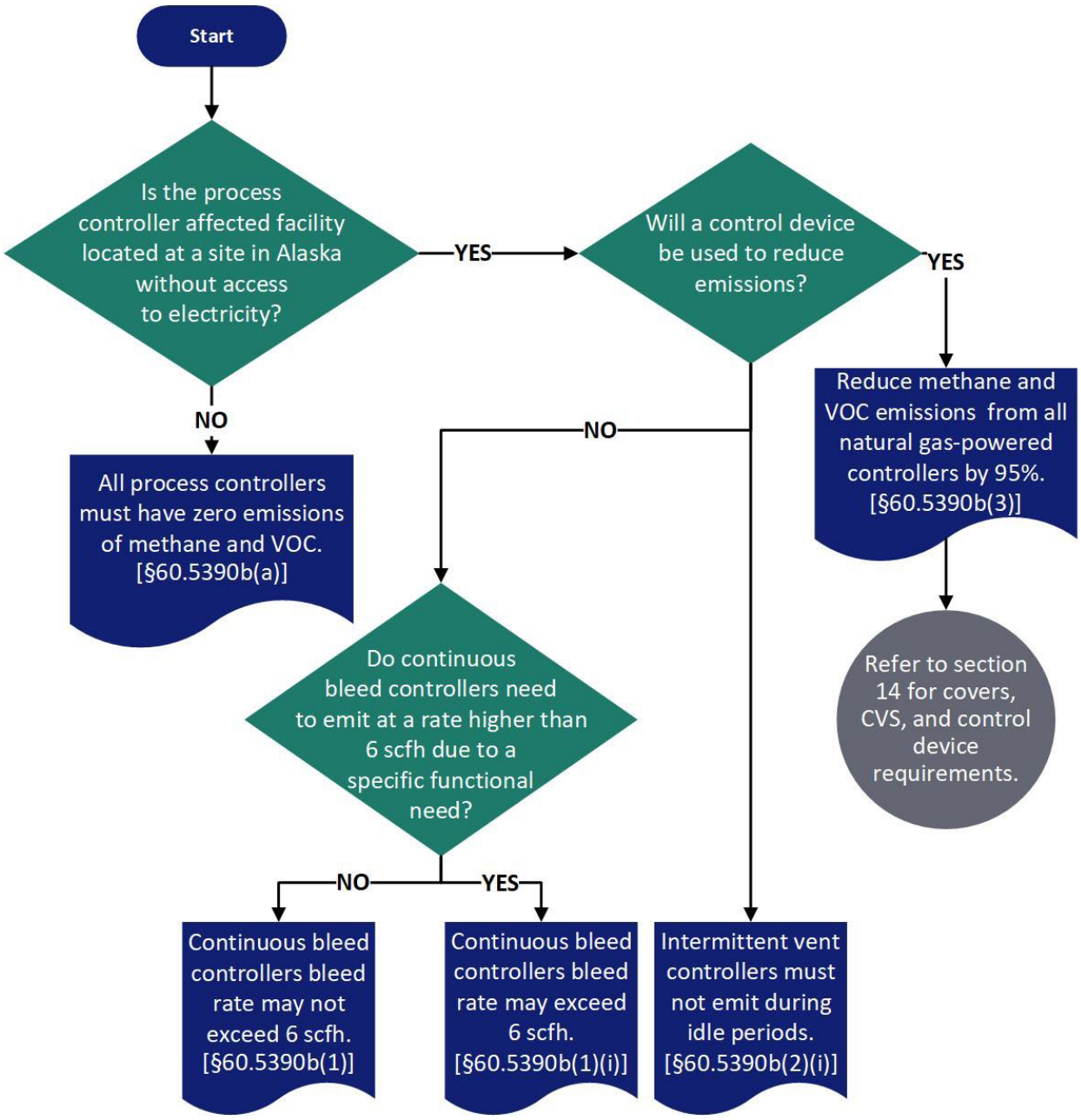
For each process controller affected facility you must design and operate each process controller with zero emissions, except as noted below. Potential options for compliance with this standard include switching natural gas-powered process controllers to controllers powered by electricity, use of self-contained process controllers, or routing emissions from controllers to a process through a CVS. [§60.5390b(a)]

Exception to the zero emissions standard. The zero emissions standard does not apply to a process controller located at a site in Alaska without access to electrical power. For sites in

Alaska without access to electrical power, one compliance option is to route natural gas-powered process controller emissions through a CVS to a control device that achieves a 95 percent reduction in emissions. If a control device is not used at such sites, intermittent vent process controllers must not have emissions during idle periods, and continuous bleed process controllers must have a bleed rate less than six standard cubic feet per hour (scfh) unless you demonstrate that a functional need requires a bleed rate or more than six scfh. [§60.5390b(b)]

Figure 7-1 (Emission Control Requirements for Process Controller Affected Facilities) provides a summary overview for determining which of these emissions control requirements apply to your process controller affected facility.

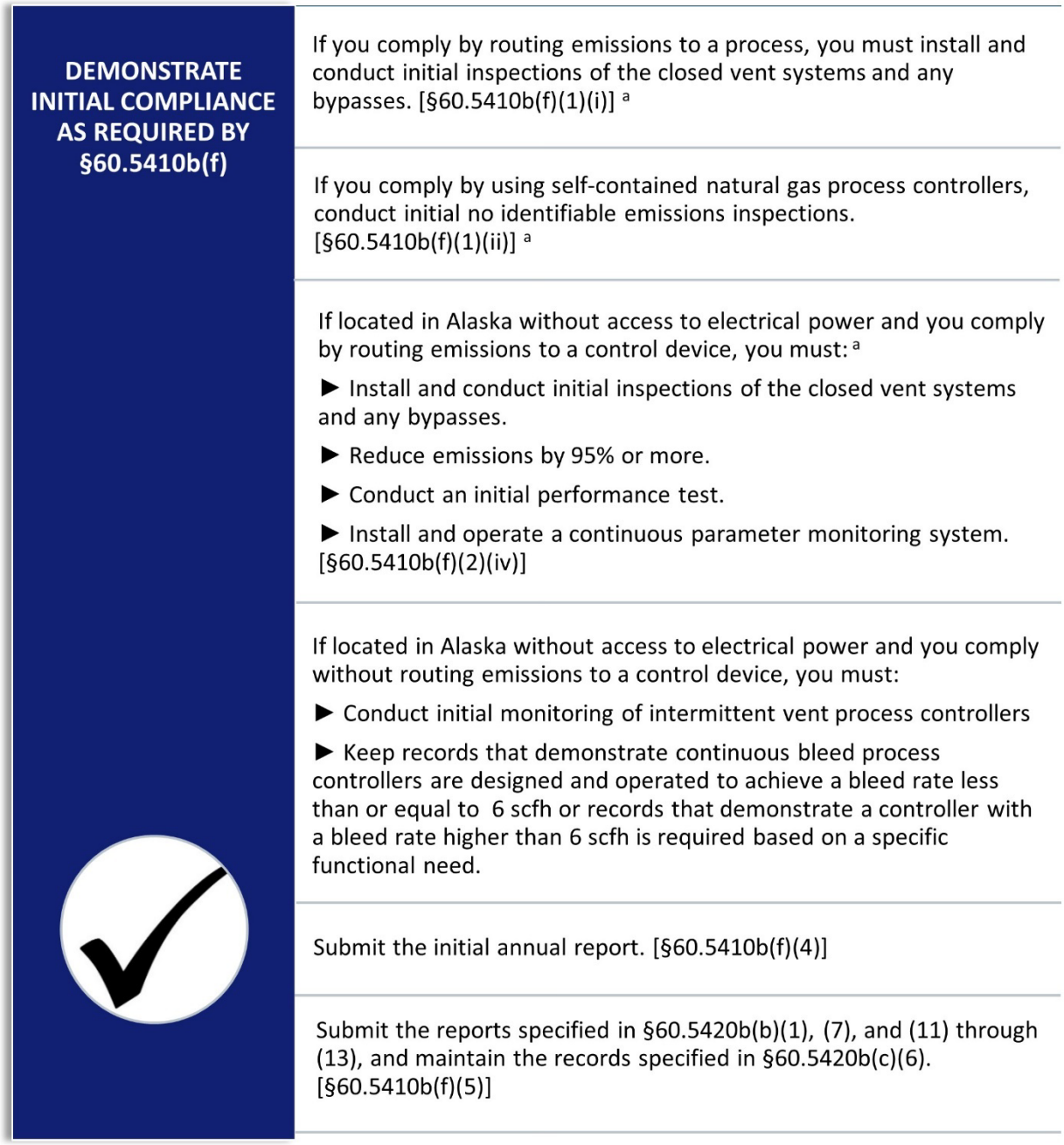
Figure 7-1. Emission Control Requirements for Process Controller Affected Facilities



7.3 How do I demonstrate initial and continuous compliance?

To demonstrate initial compliance, please refer to the summary overview of requirements in Figure 7-2 (Initial Compliance Requirements for Process Controller Affected Facilities).

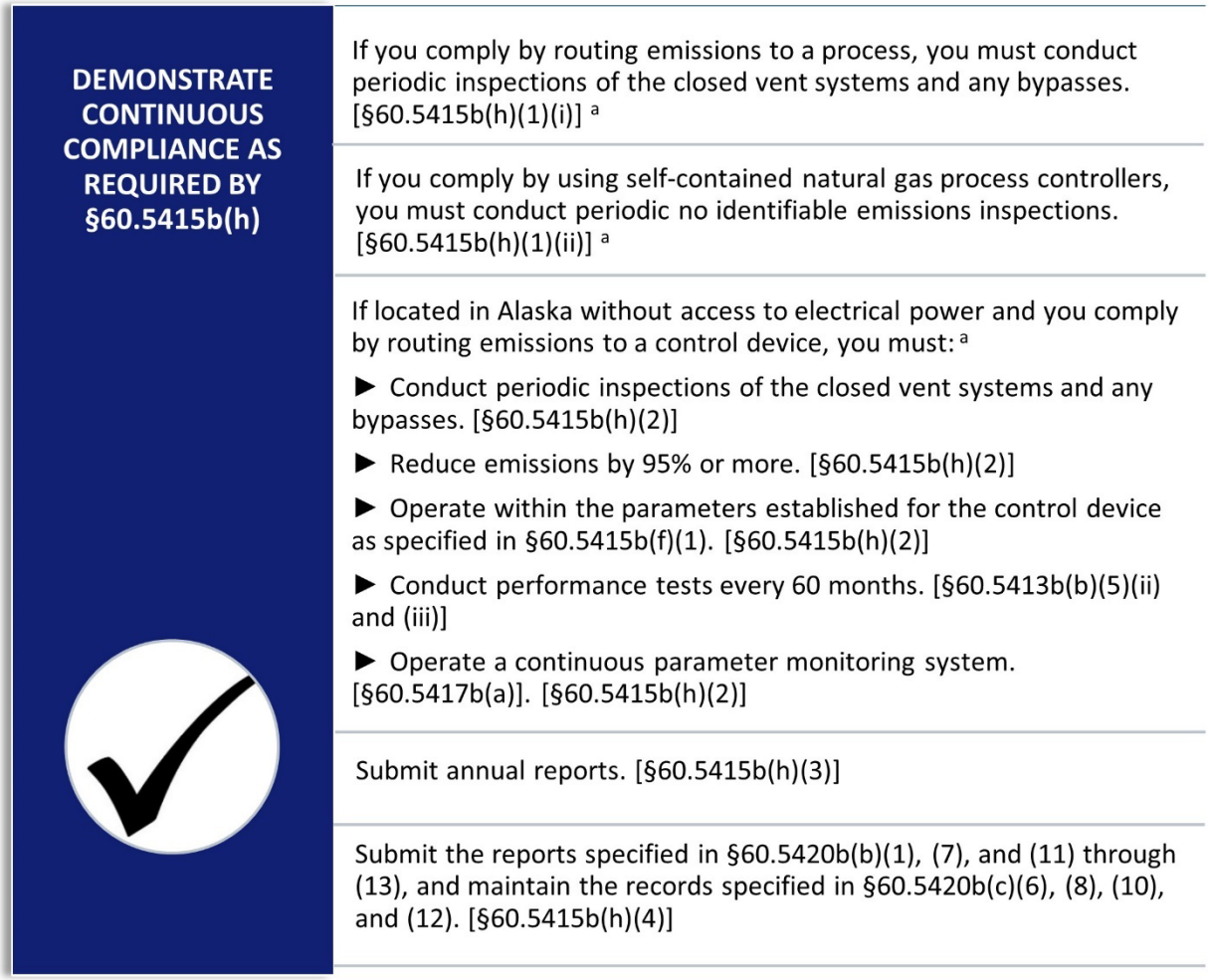
Figure 7-2. Initial Compliance Requirements for Process Controller Affected Facilities



a. See section 14.0 of this document for further information regarding the requirements for CVSs and control devices for process controllers.

To demonstrate continuous compliance, please refer to the summary overview of requirements in Figure 7-3 (Continuous Compliance Requirements for Process Controller Affected Facilities).

Figure 7-3. Continuous Compliance Requirements for Process Controller Affected Facilities



a. See section 14.0 of this document for further information regarding the requirements for CVSs and control devices for process controllers.

7.4 When must I comply?

Process controller affected facilities (except those located in Alaska without access to electrical power) must either comply with the zero emissions standards of §60.5390b(a) or the emissions control standards of §60.5390b(b) by May 7, 2024. Such facilities that startup between May 7, 2024, and May 6, 2025, must also comply with these requirements. All process controller affected facilities (except those located in Alaska without access to electrical power) must comply with the zero emissions standard of §60.5390b(a) by May 7, 2025, or upon startup, if startup occurs on or after May 7, 2025. [§60.5370b(e)(5)]

Affected process controller facilities located in Alaska without access to electrical power, must be in compliance with the emissions control standards of §60.5390b(b) no later than May 7, 2024, or upon startup, whichever is later. [§60.5370b(a)]

For all process controller affected facilities, the initial compliance period begins on May 7, 2024, or upon startup date, whichever is later, and ends no later than one year after the initial startup date for the affected facility or no later than May 7, 2025. [§60.5410b introductory text] You must submit your first annual report within 90 days of the end of the initial compliance period, as described above and submit each subsequent annual report within one year of the previous annual report. [§60.5420b(b)] You must conduct an initial performance test, as applicable, within 180 days of startup, or by May 7, 2024, whichever is later. [§60.5413b(b)(5)]

Figures 7-4 (Compliance Schedule for Process Controller Affected Facilities (Except Those Located in Alaska Without Access to Electrical Power)) and 7-5 (Compliance Schedule for Process Controller Affected Facilities Located in Alaska Without Access to Electrical Power) provide summary overviews of the compliance schedule for process controller affected facilities.

Figure 7-4. Compliance Schedule for Process Controller Affected Facilities (Except Those Located in Alaska Without Access to Electrical Power)

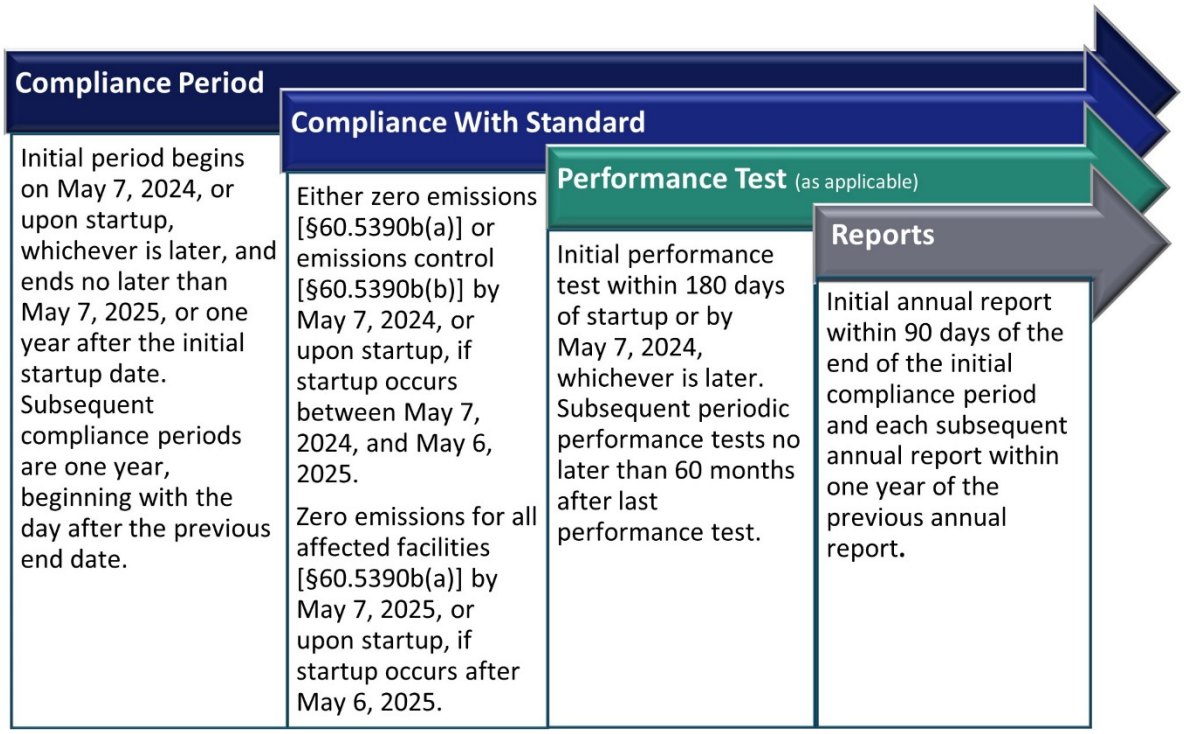
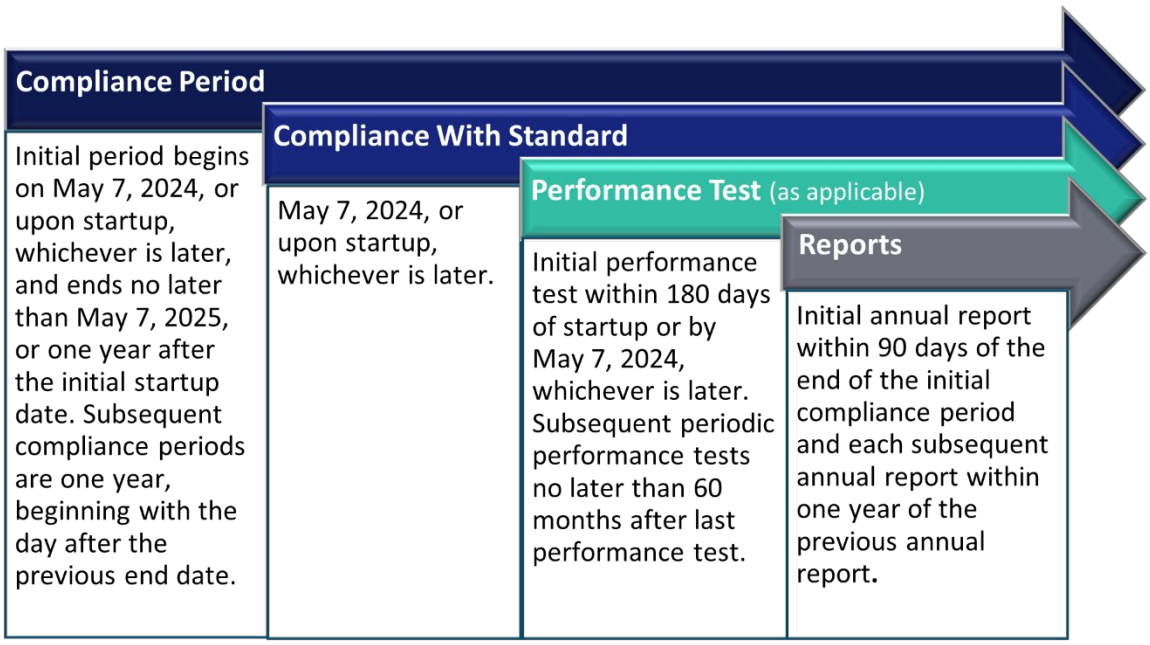


Figure 7-5. Compliance Schedule for Process Controller Affected Facilities Located in Alaska Without Access to Electrical Power



7.5 What testing or monitoring is required?

If you use a CVS to capture and route emissions to a process, you must meet the CVS requirements in section 14.0 (Covers, Closed Vent Systems, and Control Devices).

If your site is located in Alaska without access to electrical power and you use a control device to comply with the rule, you must meet the CVS requirements in section 14.0 Covers, closed vent systems, and control devices.

For sites located in Alaska without access to electrical power that do not use a control device to comply with the rule, there are monitoring requirements for intermittent vent process controllers. Initial and periodic monitoring of these process controllers, using OGI at the same frequency as specified for fugitive emissions components at the same type of site, must be conducted to ensure they do not emit during idle periods. When emissions are detected, the process controller must be repaired within 5 calendar days of the date that emissions were detected. [§§60.5390b(b)(2) and 60.5410b(f)(2)]

7.6 What, when and to whom must I report?

In addition to the information outlined in section 1.4.3 (Requirements applicable to all affected facilities) of this guide, you must include the information outlined in §60.5420b(b)(7) of the rule in your initial and annual reports for your process controller affected facility. If you use

a CVS or a CVS and control device to comply with the standards, you also must submit the applicable information in §60.5420b(b)(11) through (13).

7.7 What records must I keep?

You must maintain the records for your process controller affected facility. Specifically, you must maintain the records outlined in §60.5420b(c)(6). In addition, if you use a CVS or a CVS and control device to comply with the standards, you must maintain the records in §60.5420b(c)(8) and (c)(10) through (13), as applicable.

8.0 GHG and VOC Standards for Pump Affected Facilities

8.1 How do I determine if my pump is an affected facility?

The rule applies to the collection of natural gas-driven pumps constructed, modified, or reconstructed after December 6, 2022, as follows: [§60.5365b(h)]

- The affected facility is the collection of all natural gas-driven pumps located at a well site, centralized production facility, onshore natural gas processing plant, or compressor station.
- Pumps not driven by natural gas are not part of the affected facility.

Definitions

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.

8.2 How do I comply?

For each pump affected facility you must reduce GHG and VOC emissions. The control requirements depend on whether the process controller is located at a site that has access to electrical power, at a site without access to electrical power and that has three or more natural gas-driven diaphragm pumps, or at a site without access to electrical power that has fewer than three natural gas-driven diaphragm pumps.

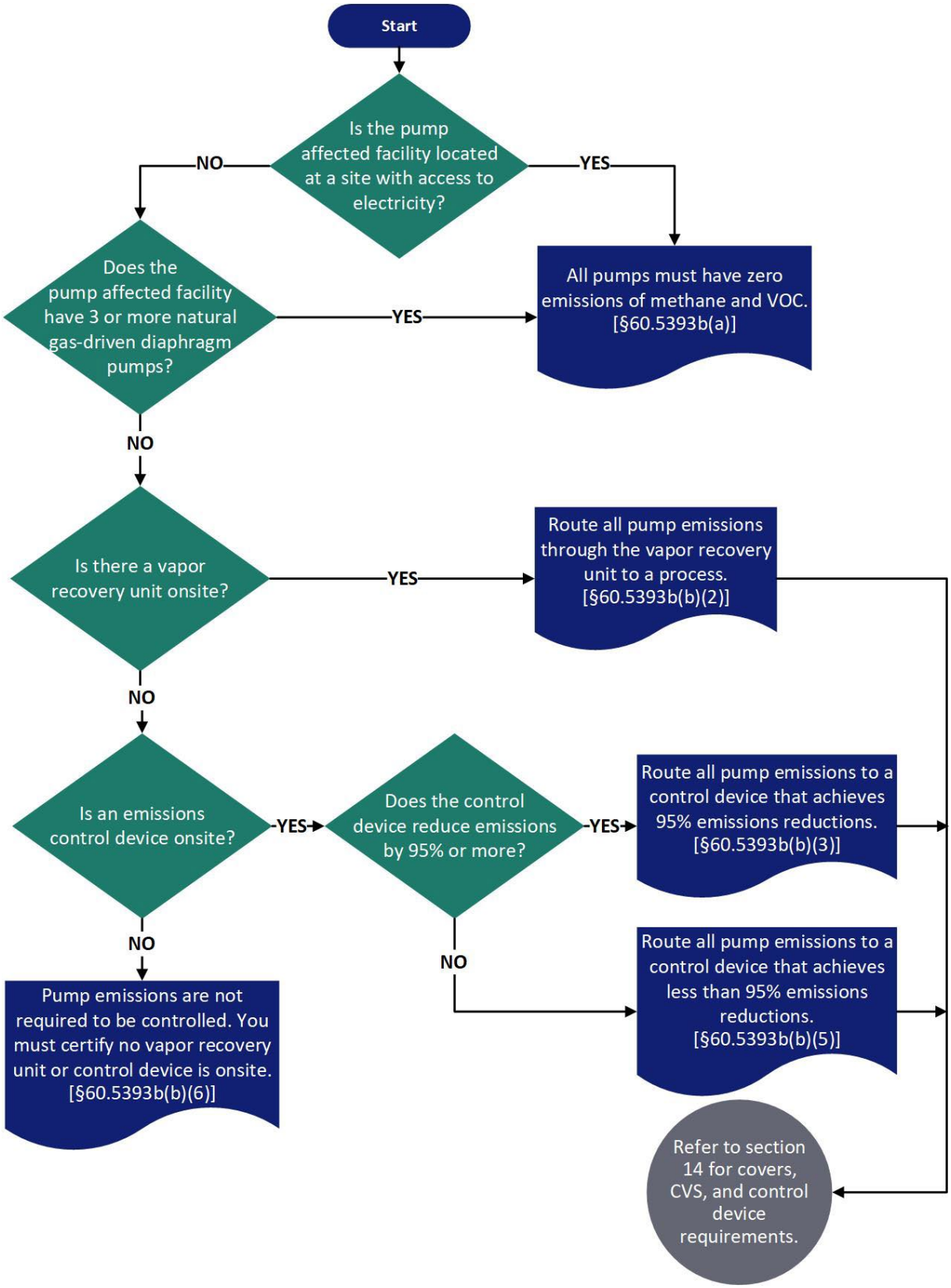
For sites with access to electrical power and for sites without access to electrical power that have three or more natural gas-driven diaphragm pumps there must be zero emissions

from pumps. Potential options for compliance with this standard include switching from natural gas-powered pumps to pumps powered by electricity or compressed air or routing emissions through a CVS to a process. [§60.5393b(a)]

For sites without access to electrical power that have fewer than three natural gas-driven diaphragm pumps, you must route all-natural gas-driven pump emissions to a process if a vapor recovery unit is onsite. If there is no vapor recovery unit onsite, you must route all-natural gas-driven pump emissions to a control device if one is onsite. If a control device is onsite that achieves a 95 percent or greater reduction in emissions, you must route pump emissions to that control device. If there is no control device onsite that reduces emissions by 95 percent or greater, you must route to a control device that reduces emissions by less than 95 percent. If no control device is onsite, you are not required to reduce emissions from pumps, but you must certify that no vapor recovery unit or emissions control device is onsite. [§60.5393b(b)]

Figure 8-1 (Requirements for Pump Affected Facilities) provides a summary overview of the process for determining which of these emissions control requirements apply to your pumps affected facility.

Figure 8-1. Requirements for Pump Affected Facilities



8.3 How do I demonstrate initial and continuous compliance?

To demonstrate initial compliance, please refer to the summary overview in Figure 8-2 (Initial Compliance Requirements for Pump Affected Facilities).

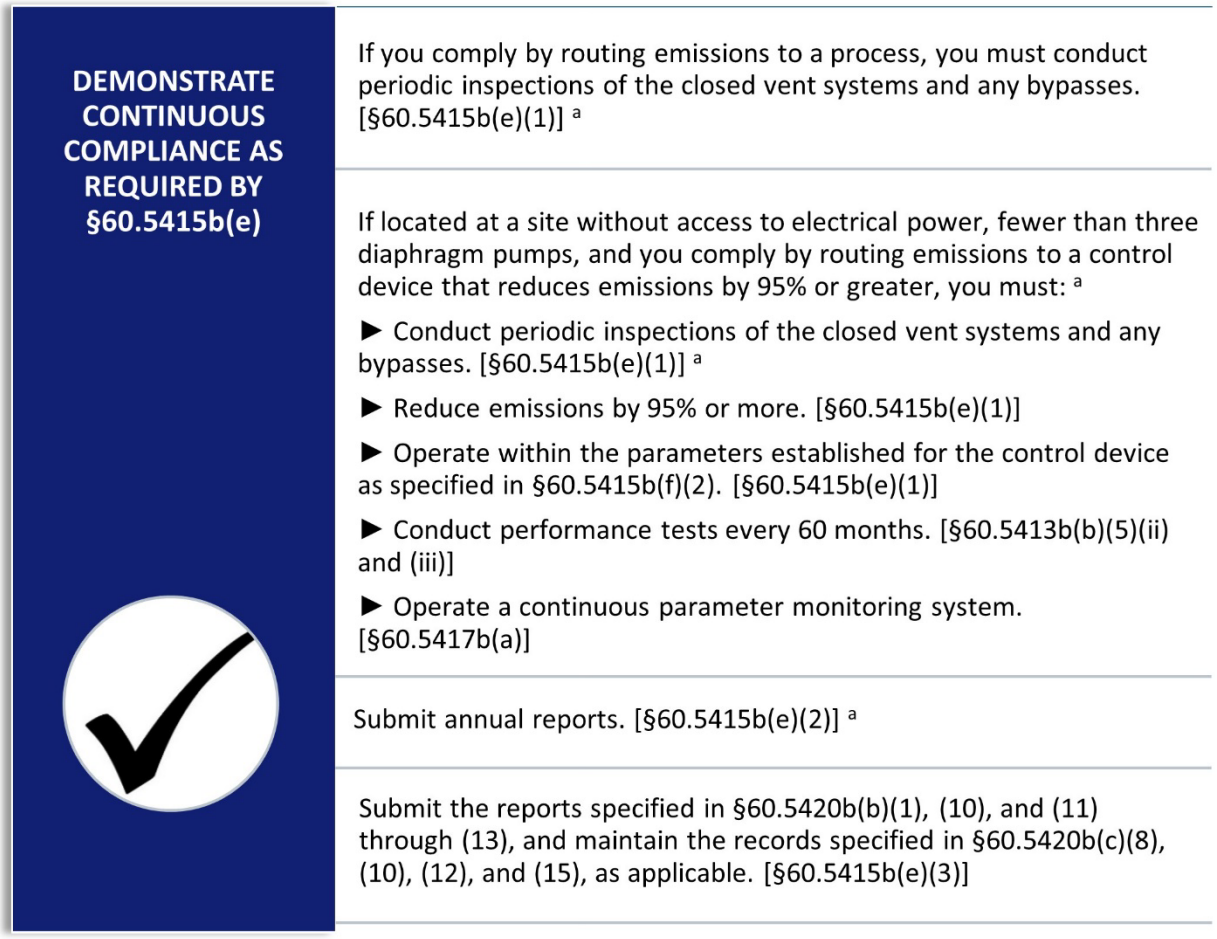
Figure 8-2. Initial Compliance Requirements for Pump Affected Facilities

DEMONSTRATE INITIAL COMPLIANCE AS REQUIRED BY §60.5410b(g)	If you comply by routing emissions to a process, you must install and conduct initial inspections of the closed vent systems and any bypasses. [§60.5410b(g)(1)(ii) and (iv)] [a]
	If located at a site without access to electrical power, fewer than three diaphragm pumps, and you comply by routing emissions to a control device that reduces emissions by 95% or greater, you must: [a] ► Install and conduct initial inspections of the closed vent systems and any bypasses. ► Reduce emissions by 95% or more. ► Conduct an initial performance test. ► Install and operate a continuous parameter monitoring system. [§60.5410b(g)(1) through (v)]
	If located at a site without access to electrical power, fewer than three diaphragm pumps, no vapor recovery unit, and a control device that reduces emissions by less than 95%, you must submit a certification that there is no vapor recovery unit onsite or a control device onsite that reduces emissions by 95% or greater. [§60.5410b(g)(2)(i)]
	If located at a site without access to electrical power, fewer than three diaphragm pumps, and no vapor recovery unit or control device onsite, you must submit a certification that there is no vapor recovery unit or control device onsite. [§60.5410b(g)(2)(ii)]
	If it is technically infeasible to route emissions to a process or control device onsite, you must submit a certification of this technical infeasibility. [§60.5410b(g)(2)(iii)]
	Submit the initial annual report. [§60.5410b(g)(3)]
	Submit the reports specified in §60.5420b(b)(1), (10), and (11) through (13), and maintain the records specified in §60.5420b(c)(8), and (10) through (13), and (15), as applicable. [§60.5410b(g)(4)]

a. See section 14.0 of this document for further information regarding the requirements for CVSs and control devices for pumps.

To demonstrate continuous compliance, please refer to the summary overview of requirements in Figure 8-3 (Continuous Compliance Requirements for Pump Affected Facilities).

Figure 8-3. Continuous Compliance Requirements for Pump Affected Facilities



a. See section 14.0 of this document for further information regarding the requirements for CVSs and control devices for pumps.

8.4 When must I comply?

Pump affected facilities at sites with access to electrical power and all sites with three or more diaphragm pumps must either comply with the zero emissions standard of §60.5393b(a) or the emissions control standards of §60.5393b(b) by May 7, 2024. Such facilities that startup between May 7, 2024, and May 6, 2025, must also comply with these requirements. All pump affected facilities at sites with access to electrical power and all sites with three or more

diaphragm pumps must comply with the zero emissions standard of §60.5393b(a) by May 7, 2025, or upon startup, if startup occurs on or after May 7, 2025. [§60.5370b(e)(6)]

Pump affected facilities located at sites without access to electrical power and that also have three or fewer diaphragm pumps must be in compliance with the emissions control standards of §60.5393b(b) no later than May 7, 2024, or upon startup, whichever is later. [§60.5370b(a)]For all affected pump facilities, the initial compliance period begins on May 7, 2024, or upon initial startup, whichever is later, and ends no later than one year after the initial startup date or no later than May 7, 2025. [§60.5410b introductory text] You must submit your initial annual report within 90 days of the end of the initial compliance period, as described above and submit each subsequent annual report within one year of the previous annual report. [§60.5420b(b)] You must conduct an initial performance test, as applicable, within 180 days of initial startup or by May 7, 2024, whichever is later. [§60.5413b(b)(5)]

If you later install a vapor recovery unit or control device, you must be in compliance with the requirements to route emissions to a process or control device within 30 days of startup of the vapor recovery unit or control device. [§60.5393b(b)(6)(i)]

Figures 8-4 (Compliance Schedule for Pump Affected Facilities Located at Sites with Access to Electrical Power and Sites with Three or More Diaphragm Pumps) and 8-5 (Compliance Schedule for Pump Affected Facilities Located at Sites Without Access to Electrical Power and Fewer than Three Diaphragm Pumps) provide summary overviews of the compliance schedule for pump affected facilities.

Figure 8-4. Compliance Schedule for Pump Affected Facilities Located at Sites with Access to Electrical Power and Sites with Three or More Diaphragm Pumps

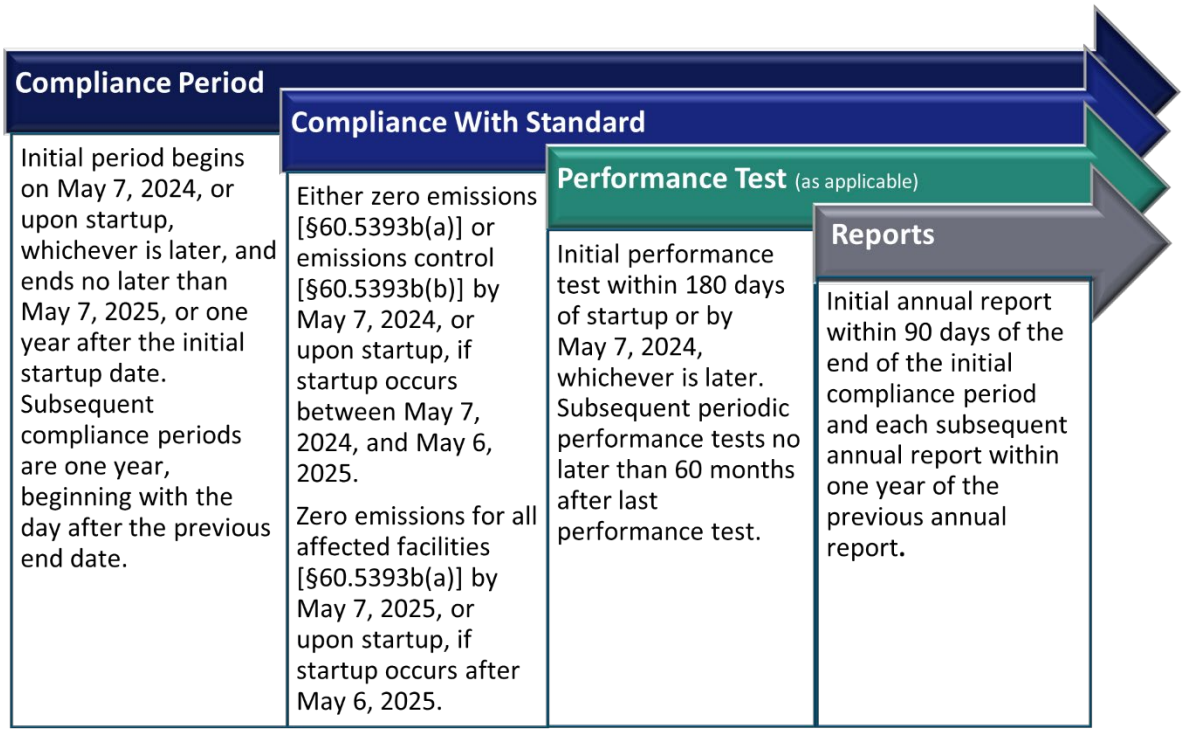
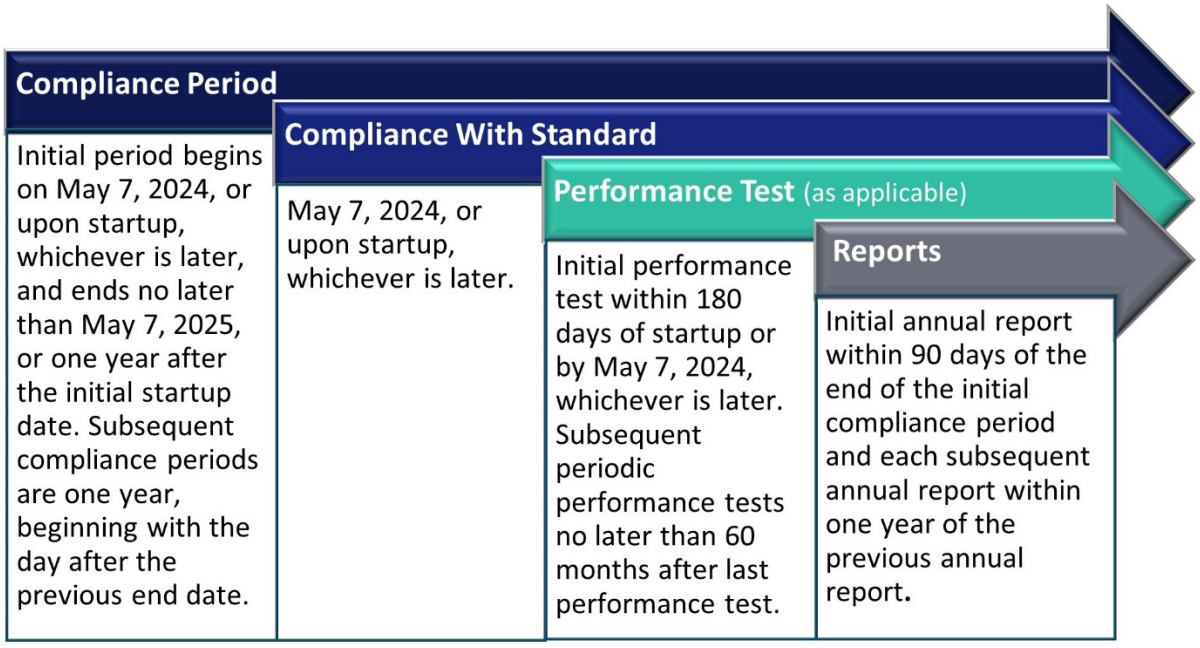


Figure 8-5. Compliance Schedule for Pump Affected Facilities Located at Sites Without Access to Electrical Power and Fewer than Three Diaphragm Pumps



8.5 What testing or monitoring is required?

If you use a CVS to capture and route emissions to a process, you must meet the CVS requirements in section 14.0 (Covers, Closed Vent Systems, and Control Devices).

For sites that use a control device to comply with the rule, you must meet the CVS requirements in section 14.0 (Covers, Closed Vent Systems, and Control Devices). For a control device that achieves less than a 95 percent reduction in emissions, performance tests are not required.

8.6 What, when and to whom must I report?

In addition to the information outlined in 1.4.3 (Requirements applicable to all affected facilities) above, you must include the information outlined in §60.5420b(b)(10) of the rule in your initial and annual reports for your pump affected facility. If you use a CVS and control device to comply with the standards, you also must submit the applicable information in §60.5420b(b)(11) through (13).

8.7 What records must I keep?

You must maintain records for your pump affected facility. Specifically, you must maintain the records outlined in §60.5420b(c)(15). In addition, if you use a CVS and control device to comply with the standards, you must maintain the records in §60.5420b(c)(8) through (13), as applicable.

9.0 GHG and VOC Standards for Storage Vessel Affected Facilities

9.1 How do I determine if my storage vessel is an affected facility?

Subpart OOOOb storage vessel requirements apply to a tank battery with a potential for VOC emissions greater than or equal to 6 tpy or with the potential for methane emissions greater than or equal to 20 tpy [§60.5365b(e)] that commenced construction, modification , or reconstruction after December 6, 2022. [§60.5365b introductory text]

Definitions

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 nonearthed 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)(7)(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.

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.

9.1.1 Modification and Reconstruction

Subpart OOOOb establishes specific criteria for what constitutes a modification or reconstruction for determining when an existing tank battery becomes a storage vessel affected facility. [§60.5365b(e)(3)] Modification of a tank battery occurs when the potential for VOC emissions meet or exceed 6 tpy or the potential for methane emissions meet or exceed 20 tpy after one of the actions listed below occur:

- A storage vessel is added to an existing tank battery.
- One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases.
- 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).
- 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 one of the actions) determination of the potential for VOC or methane emissions.

[§60.5365b(e)(3)(ii)(A) through (D)]

Reconstruction of a tank battery occurs when the potential for VOC emissions meet or exceed 6 tpy or the potential for methane emissions meet or exceed 20 tpy after:

- at least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel; or
- the provisions of §60.15 are met for the existing tank battery.

[§60.5365b(e)(3)(i)(A) and (B)]

9.1.2 Exceptions to Storage Vessel Applicability

- 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. [§60.5365b(e)(7)]

- 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, are not subject to the rule. [§60.5395b(e)]
- A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy remains an affected facility. [§60.5365b(e)(4)]

9.1.3 Applicability Determination Procedures

You must determine your potential for VOC and methane emissions according to the determination method and deadline in Figure 9-1 (Emissions Determination Procedures and Deadline). [§60.5365b(e)(2)] For purposes of making the determination, a "generally acceptable model or calculation methodology" must account for flashing, breathing, and working losses. When required to use the "maximum average daily throughput", this means the earliest calculation of daily average throughput to the tank battery over the days that production is routed to the tank battery during the 30-day potential to emit (PTE) evaluation period employing generally accepted methods, as follows:

- 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.
- 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.

Further, a "legally and practicably enforceable" limit must include all of the criteria specified at §60.5365b(e)(2)(i)(A) through (F) including:

- A quantitative production and operational limit or a quantitative operational limit;
- An averaging time for the limit that is equal to or less than 30 days;

- Parametric limits for the production/operational limits and on-going monitoring of the parametric limits;
- Where a control device is used to achieve an operational limit, the control device must be performance tested and the parametric limits must be established during the performance test; and
- Recordkeeping and reporting which demonstrates continuous compliance with the limits or other operating characteristics.

Table 9-1. Emissions Determination Procedures and Deadline

Location of Tank Battery	Deadline for Emissions Determination	Determination Method
Well site or centralized production facility. [§60.5365b(e)(2)(ii)]	➢ Within 30 days after startup of production, or ➢ Within 30 days of one of the following actions at an existing tank battery: • at least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel; • the provisions of §60.15 are met for the existing tank battery; • a storage vessel is added to an existing tank battery; • one or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases; • the 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).	➢ You *must* determine the PTE for your tank battery using: • A generally accepted model or calculation methodology, and • The maximum average daily throughput for a 30-day period of production. ➢ You *may* consider in the determination any legally and practically enforceable emission limit in an operating permit or other requirement established under a federal, state, local or tribal authority. [§60.5365b(e)(2)] ➢ You do not need to include vapor that is recovered and vented to a process through a vapor recovery unit (VRU) in your calculations, provided that you comply with §60.5365b(e)(5). [§60.5365b(e)]

Location of Tank Battery	Deadline for Emissions Determination	Determination Method
Other than a well site or centralized production facility. [a] [§60.5365b(e)(2)(iii)]	➢ Prior to startup of the facility, or ➢ Within 30 days of one of the following actions at an existing tank battery: • at least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel; • the provisions of §60.15 are met for the existing tank battery; • a storage vessel is added to an existing tank battery; • one or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases; • an existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent determination of the potential for VOC or methane emissions.	➢ 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 ➢ 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. [§60.5365b(e)]

a. Including, but not limited to compressor stations and onshore natural gas processing plants.

9.1.4 Applicability for storage vessel affected facilities removed from service or returned to service.

A storage vessel affected facility or portion of a storage vessel affected facility that is removed from service is no longer an affected facility during the period of removal, provided you meet the requirements of §60.5395b(c).

A storage vessel affected facility or portion of a storage vessel affected facility that is returned to service and 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, or portion of a storage vessel affected facility, or used to expand a storage vessel affected facility is subject to the same requirements that apply to the storage vessel affected facility being replaced or expanded. [§60.5365b(e)(6); §60.5395b(c)]

Definition

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 (and you meet the requirements of §60.5395b(c) to empty and degas the storage vessel and submit the appropriate notifications in §60.5420b(b)(8).

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.

9.2 How do I comply?

You must determine the potential for VOC and methane emissions from your tank battery. [§60.5395b(a)(1)] If the PTE for your tank battery is determined to be equal to or greater than 6 tpy of VOC or 20 tpy of methane, then you must reduce your emissions by 95 percent. [§60.5395b(a)(2)] You must equip each storage vessel in the tank battery with a cover and capture your emissions and reduce emissions by using a control device or routing the emissions to a process. [§60.5395b(b)] See section 14.0 (Covers, Closed Vent Systems, and

Control Devices) of this guide for an overview of requirements for covers, CVS, and control devices.

9.2.1 Mass Emissions Rate (4 tpy VOC/14 tpy methane) Option

After compliance with the 95 percent reduction of emissions for at least 12 consecutive months, you may continue to comply with the 95 percent reduction requirements or can change your method of compliance to an uncontrolled actual VOC emissions rate of less than 4 tpy and an uncontrolled actual methane emission rate of less than 14 tpy. [§60.5395b(a)(3)] To make this change, you must:

- Comply with the 95 percent reduction of emissions for at least 12 months;
- Demonstrate that uncontrolled actual VOC emissions have remained less than 4 tpy and uncontrolled actual methane emissions have remained less than 14 tpy (as determined monthly for 12 consecutive months);
- Determine the uncontrolled actual VOC and uncontrolled actual methane emissions each month; and
- Maintain your uncontrolled actual VOC emissions at less than 4 tpy and your uncontrolled actual methane emissions less than 14 tpy, redetermined on a 12-month rolling basis.

Also:

- If at any time the uncontrolled actual emissions rate increases to 4 tpy or greater of VOC or 14 tpy or greater of methane, you must again comply with the 95 percent reduction within 30 days of the determination of the emissions increase.
- You must also cease compliance with the 4 tpy uncontrolled actual VOC emissions rate and 14 tpy uncontrolled actual methane emissions rate if the well feeding the storage vessel affected facility undergoes fracturing or refracturing (regardless of the emissions rate). Under this scenario, you must comply with the 95 percent reduction standard as soon as liquids from the well are routed to the storage vessel affected facility.

The uncontrolled actual VOC and uncontrolled actual methane emissions calculation determination is done each month using a generally accepted model or calculation methodology and based on the average throughput, temperature, and separator pressure for each month.

Figure 9-1 (Requirements for Storage Vessel Affected Facilities) and Figure 9-2 (Requirements for Storage Vessel Affected Facilities (Mass Emissions Rate Option)) provide a summary overview of the performance requirements for your storage vessel affected facility.

9.2.2 Floating Roof Alternative

Storage vessel affected facilities that do not have flashing emissions and that are not located at well sites or centralized production facilities, may be equipped with 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 40 CFR part 60, subpart Kb. You must also 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). [§60.5395b(b)(2)]

Figure 9-1. Requirements for Storage Vessel Affected Facilities

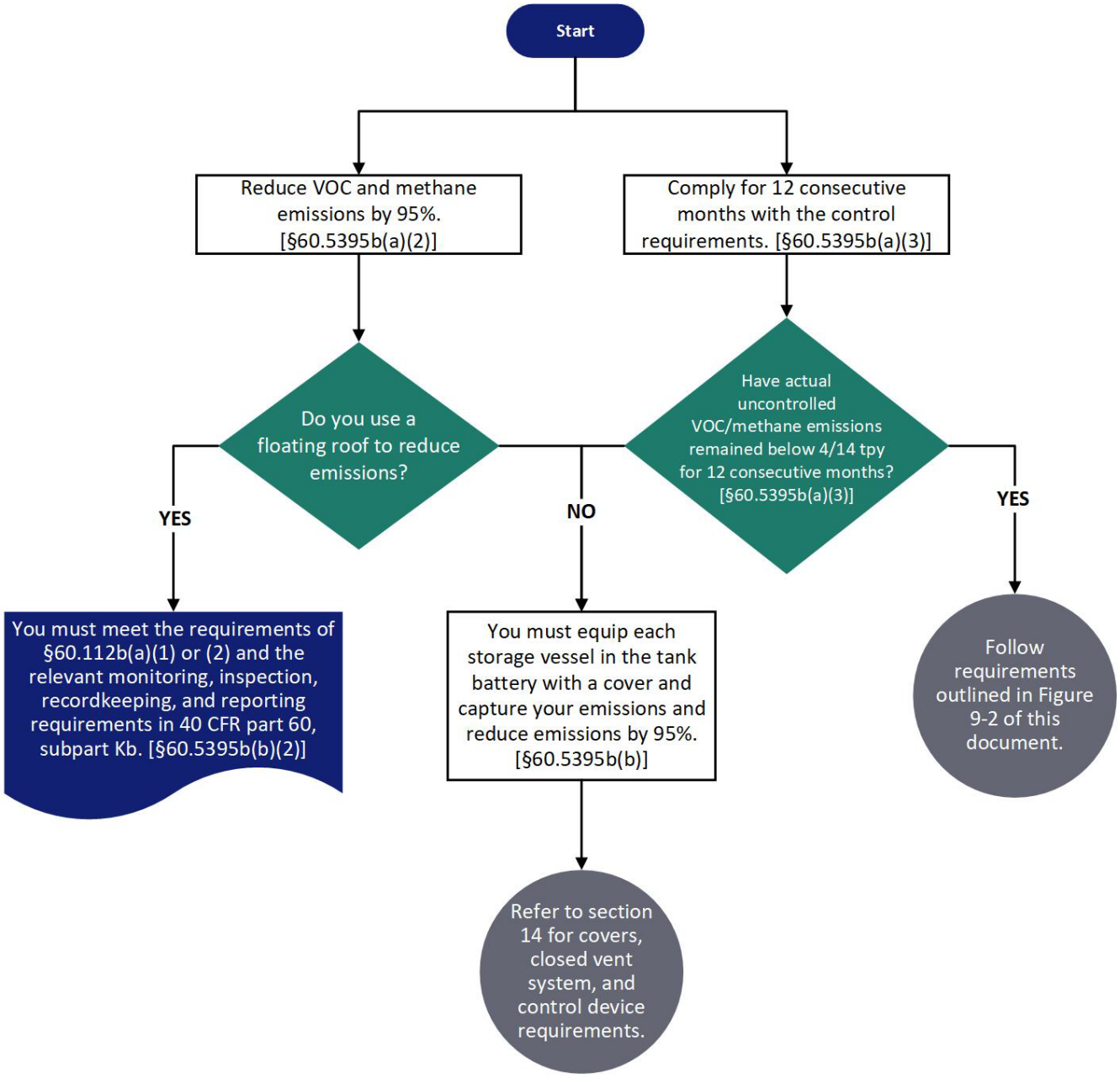
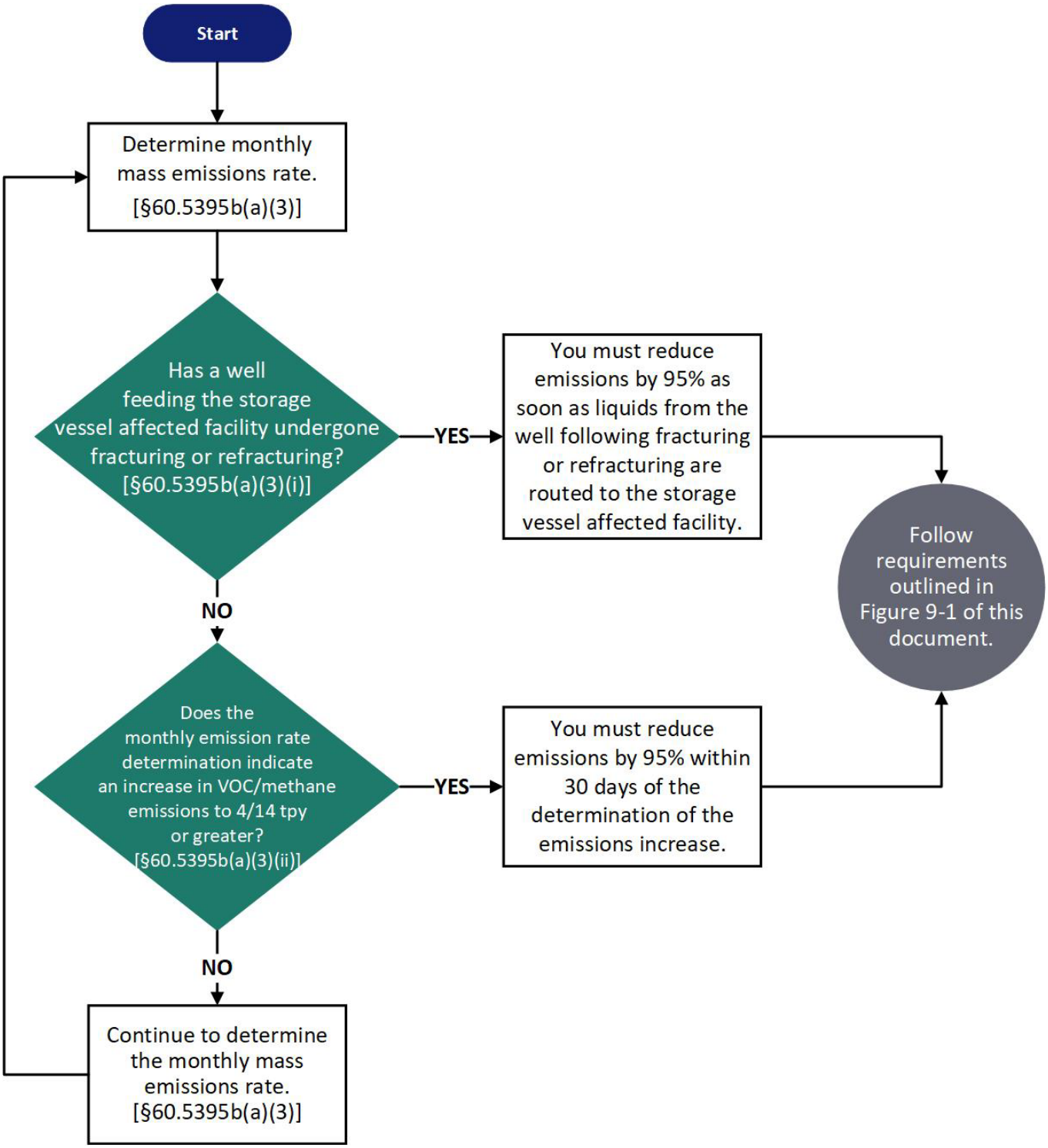


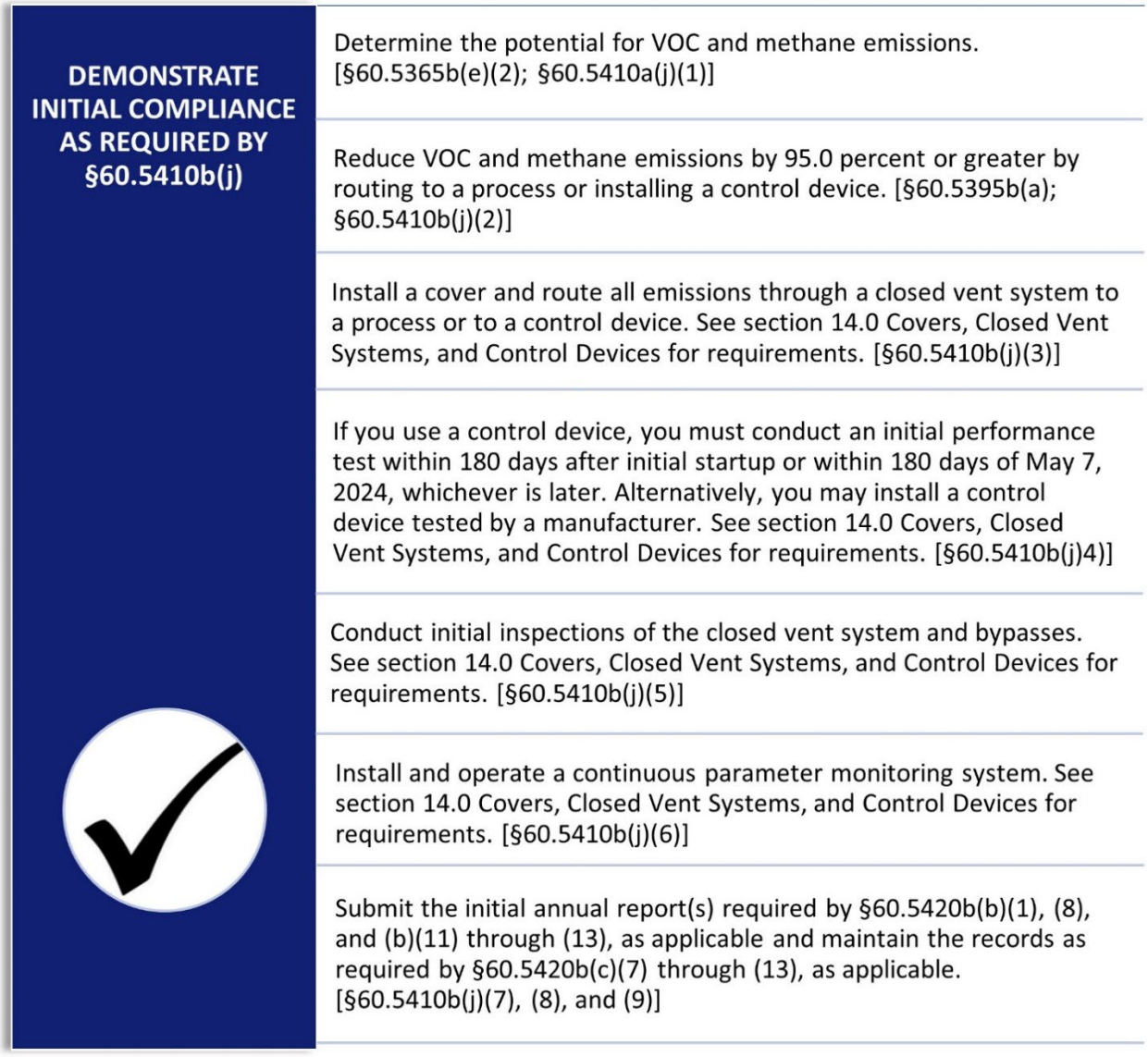
Figure 9-2. Requirements for Storage Vessel Affected Facilities (Mass Emissions Rate Option)



9.3 How to I demonstrate initial and continuous compliance?

To demonstrate initial compliance, please refer to the summary overview of requirements in Figure 9-3 (Initial Compliance Requirements for Storage Vessel Affected Facilities).

Figure 9-3. Initial Compliance Requirements for Storage Vessel Affected Facilities



Note: Each storage vessel affected facility that complies by using a floating roof, 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. 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).

To demonstrate continuous compliance, please refer to the summary overview of requirements in Figures 9-4 (Continuous Compliance Requirements for Storage Vessel Affected Facilities (95.0 Percent Reduction Option)), 9-5 (Continuous Compliance Requirements for Storage Vessel Affected Facilities (Mass Emissions Rate Option)), 9-6 (Continuous Compliance Requirements for Storage Vessel Affected Facilities Which are Removed From Service), and 9-7 (Continuous Compliance Requirements for Storage Vessel Affected Facilities Which are Returned to Service).

Figure 9-4. Continuous Compliance Requirements for Storage Vessel Affected Facilities (95.0 Percent Reduction Option)

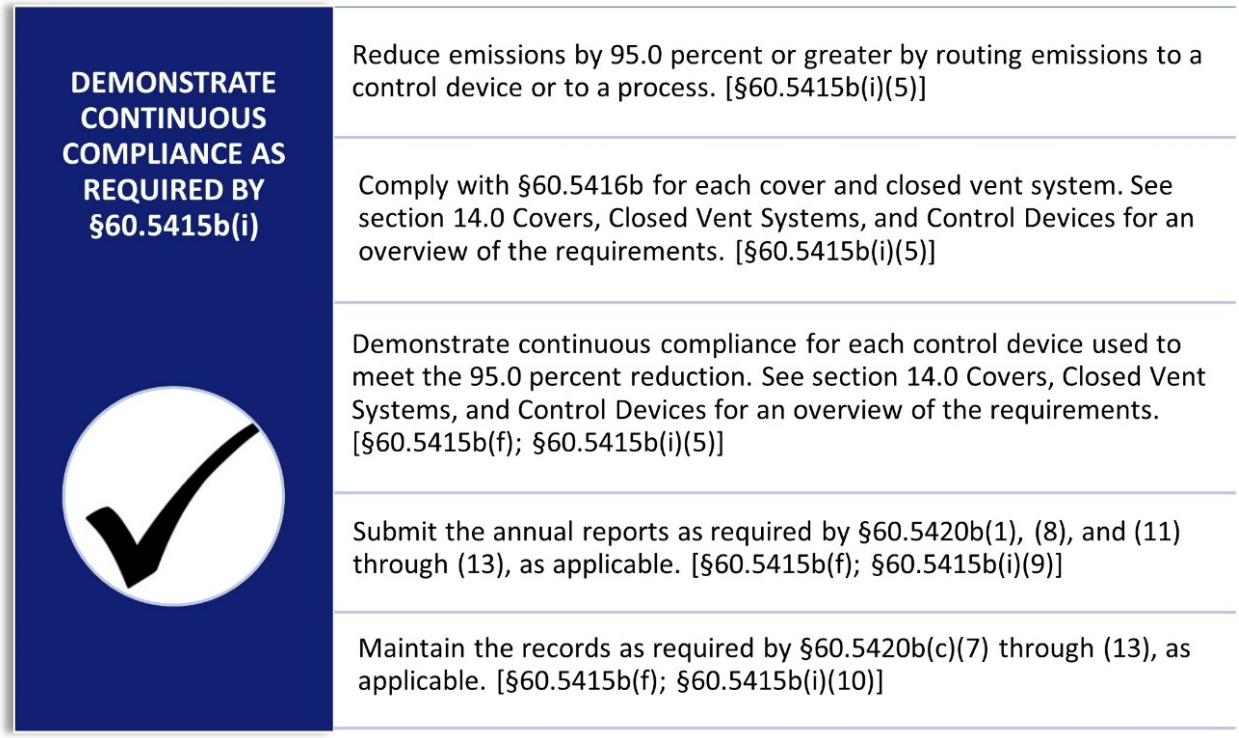


Figure 9-5. Continuous Compliance Requirements for Storage Vessel Affected Facilities (Mass Emissions Rate Option)

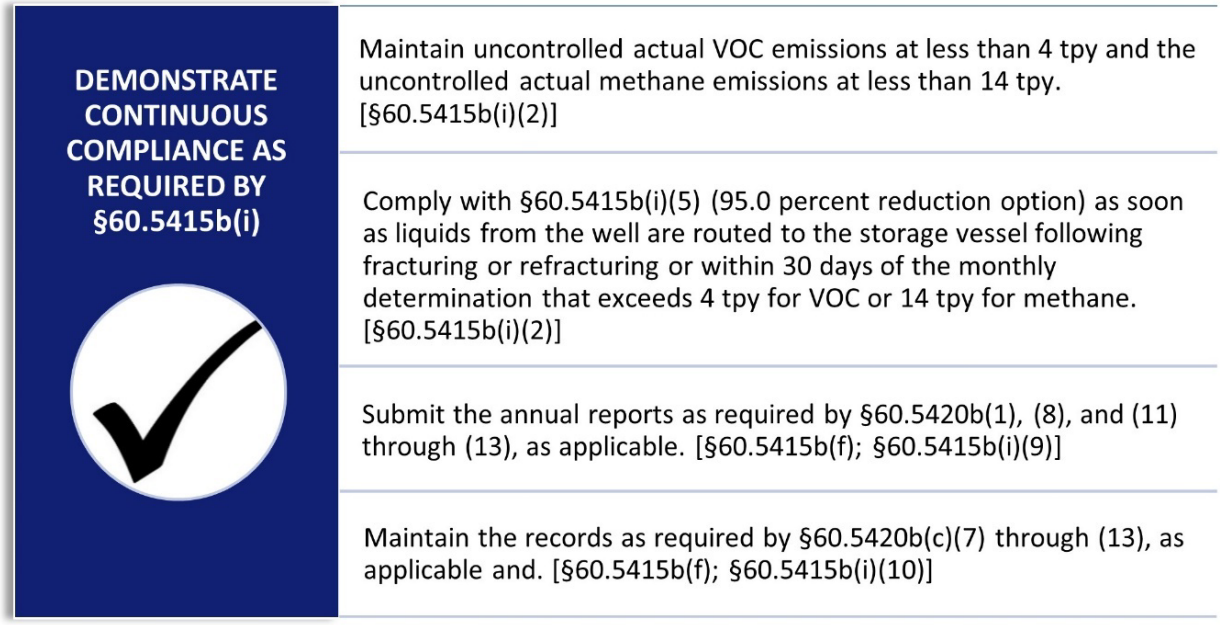


Figure 9-6. Continuous Compliance Requirements for Storage Vessel Affected Facilities Which are Removed from Service

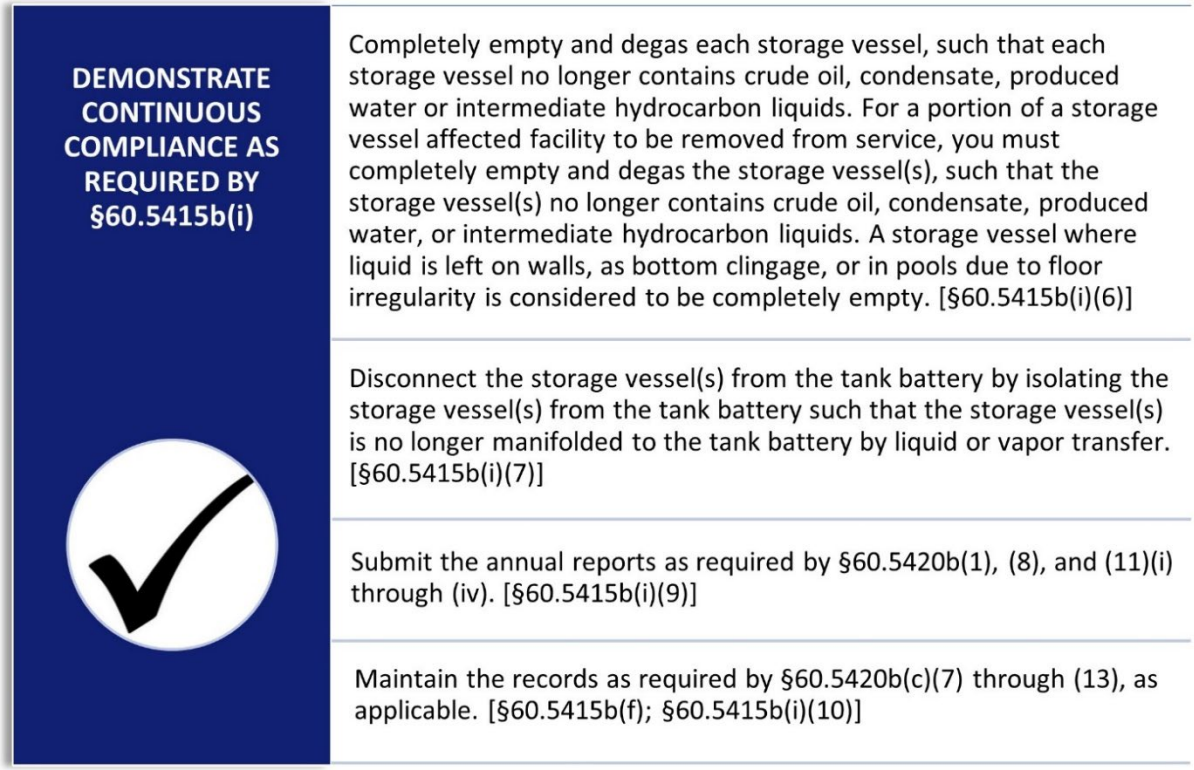
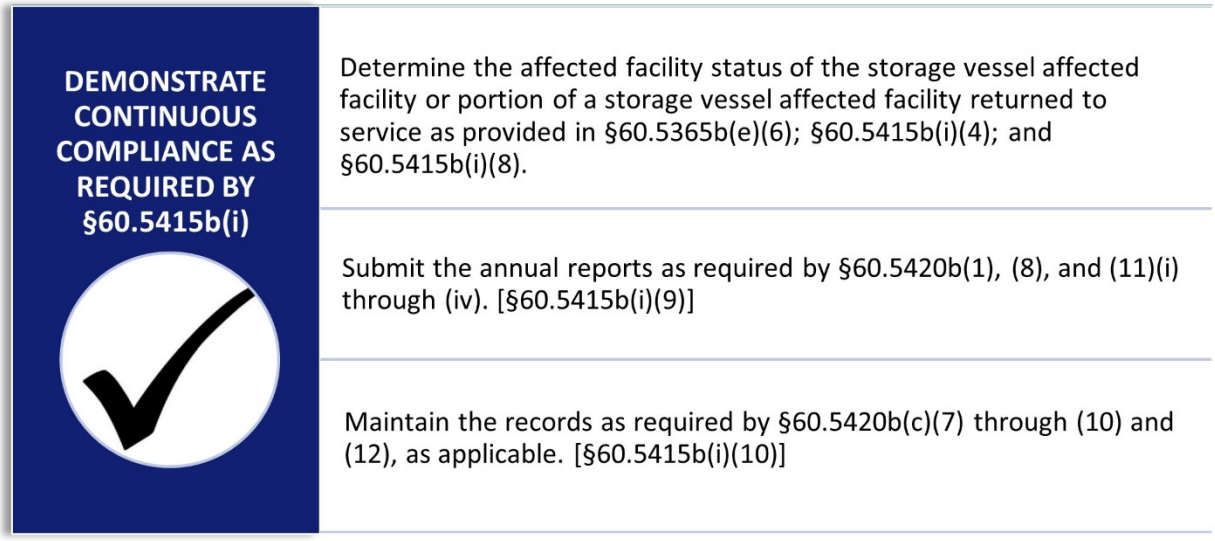


Figure 9-7. Continuous Compliance Requirements for Storage Vessel Affected Facilities Which are Returned to Service



9.4 When must I comply?

You must determine the potential for VOC and methane emissions and install controls according to the following schedule:

- Determination of potential for VOC and methane emissions:
  - For tank batteries located at well sites and centralized production facilities, within 30 days after startup of production, or within 30 days after reconstruction or modification of the storage vessel affected facility.
  - For tank batteries not located at well sites or centralized production facilities, 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. [§60.5370b(a) and (a)(2)]
- Installation of controls
  - For each storage vessel affected facility regardless of location, you must achieve the required emissions reductions within 30 days after the potential for VOC and methane emissions determination. [§60.5370b(a)(3)]

Definition

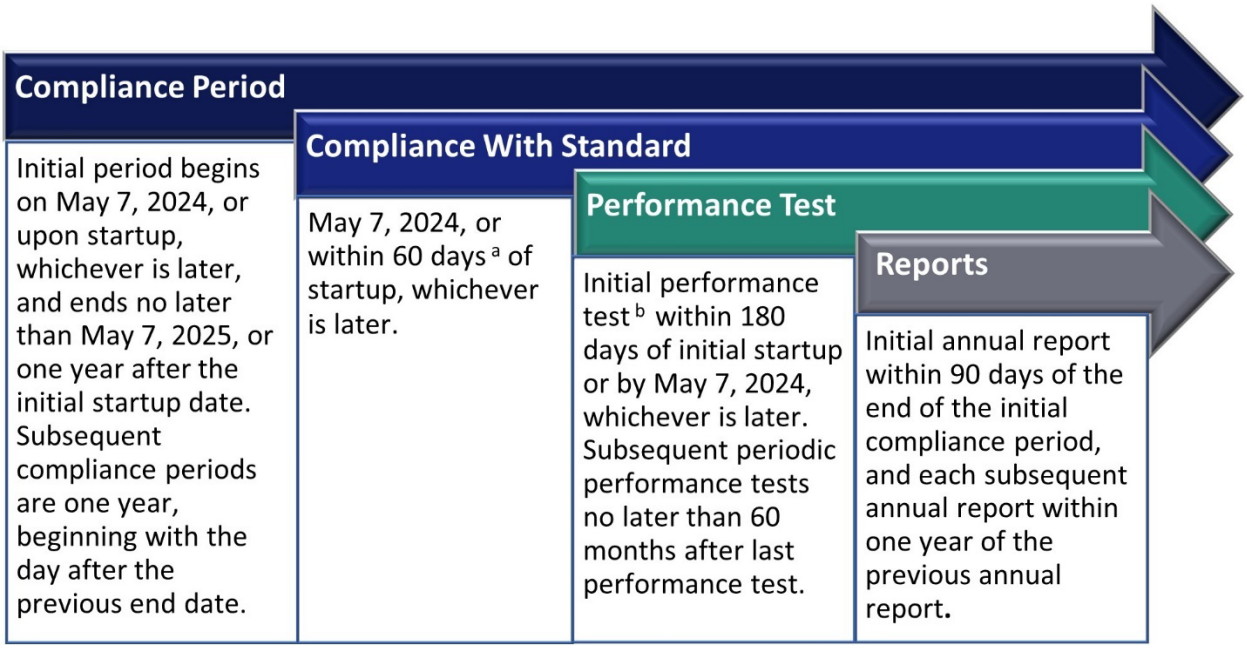
Startup of production means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.

The initial compliance period begins on May 7, 2024, or upon initial startup, whichever is later, and ends no later than one year after the initial startup date or no later than May 7, 2025. [§60.5410b introductory text]

You must submit your initial annual report within 90 days of the end of the initial compliance period, as described above and submit each subsequent annual report within one year of the previous annual report. You must conduct an initial performance test within 180 days of initial startup or by May 7, 2024, whichever is later.

Figures 9-8 (Compliance Schedule for Storage Vessels Located at a Well Site or Centralized Production Facility and 9-9 (Compliance Schedule for Storage Vessels Located at Other than a Well Site or Centralized Production Facility) provide a summary overview of the compliance schedule for your storage vessel located at a well site or centralized production facility or located at other than a well site or centralized production facility, respectively.

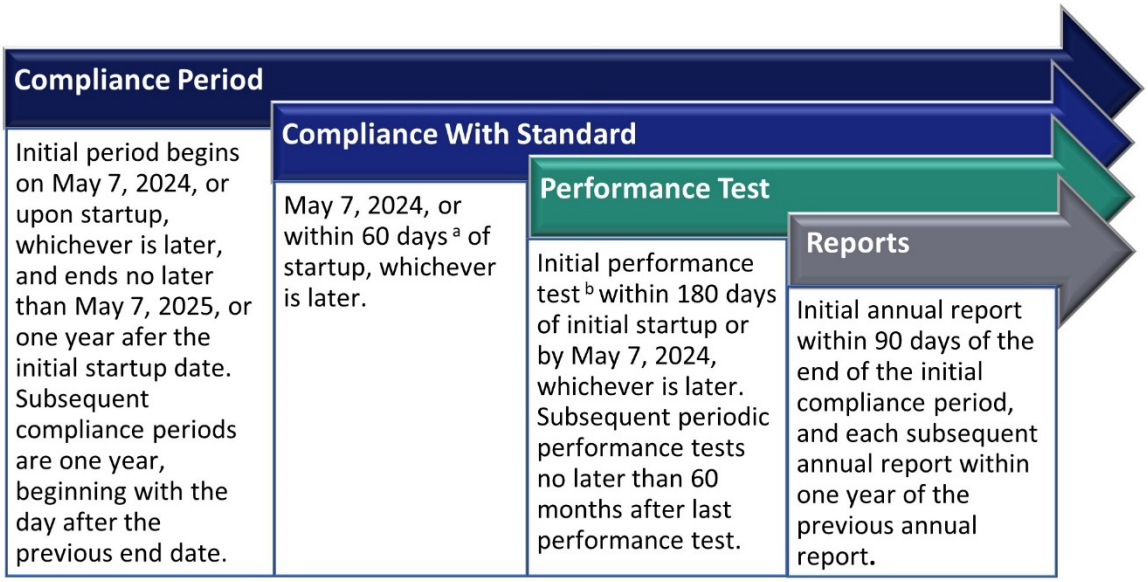
Figure 9-8. Compliance Schedule for Storage Vessels Located at a Well Site or Centralized Production Facility



a. Determination of potential for VOC and methane emissions must be done within 30 days of the startup of production, or within 30 days after an action described by §60.5365b(e)(3)(i) or (ii). Installation of controls is required within 30 days of that determination.

b. Enclosed combustion devices that are tested by the manufacturer according to the requirements of §60.5413b(d) and that are listed on the EPA website at www.epa.gov/airquality/oilandgas are not subject to the initial performance test requirements.

Figure 9-9. Compliance Schedule for Storage Vessels Located at Other than a Well Site or Centralized Production Facility



a. Determination of potential for VOC and methane emissions must be done prior to startup, or within 30 days after an action described in §60.5365b(e)(3)(i) or (ii). Installation of controls is required by May 7, 2024, or withing 30 days of that determination, whichever is later.
b. Enclosed combustion devices that are tested by the manufacturer according to the requirements of §60.5413b(d) and that are listed on the EPA website at www.epa.gov/airquality/oilandgas are not subject to the initial performance test requirements.

9.5 What testing or monitoring is required?

You must meet the requirements in section 14.0 (Covers, Closed Vent Systems, and Control Devices) of this guide. If you use a floating roof on the storage vessel, you must meet the testing and procedures according to 40 CFR part 60, subpart Kb. [§60.113b]

9.6 What, when and to whom must I report?

In addition to the information outlined in section 1.4.3 (Requirements applicable to all affected facilities) of this guide, you are also required to include the information outlined in §60.5420a(b)(8) of the rule in your initial and annual reports. If you use a CVS and control device to comply with the standards, you also must submit the applicable information in §60.5420b(b)(11) through (13).

9.7 What records must I keep?

You must maintain the records for your storage vessel affected facilities. Specifically, you must maintain the records outlined in §60.5420a(c)(7). In addition, if you use a CVS and control device to comply with the standards, you must maintain the records in §60.5420b(c)(8) through (13), as applicable.

10.0 GHG and VOC Standards for Fugitive Emissions Components Affected Facilities at Well Sites, Centralized Production Facilities and Compressor Stations

10.1 How do I determine if my collection of fugitive emissions components is an affected facility?

You are subject to the fugitive emissions monitoring requirements in 40 CFR part 60 subpart OOOOb for each fugitive emissions components affected facility, which is the collection of fugitive emissions components at a crude oil or natural gas well site, centralized production facility, or a compressor station for which you commence construction, modification, or reconstruction after December 6, 2022. [§60.5397b]

These requirements are independent of the cover and CVS requirements of §60.5411b.

Definitions

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.

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.

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.

Note: 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 §60.5465b(e) and §60.5397b.

Definitions

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.

10.2 How do I comply?

You must reduce methane and VOC emissions from fugitive emissions components affected facilities by complying with the fugitive emissions monitoring requirements outlined in this section or with the alternative GHG and VOC standards outlined in section 11.0 of this guide. If complying with the alternative standards, you must also comply with the inspection and monitoring requirements for covers and CVS. [§60.5397b introductory text and §60.5398b introductory text].

The compliance requirements are the same for fugitive emissions components affected facilities at well sites, centralized production facilities and compressor stations, with the exception of the method and the frequency of conducting the fugitive emission monitoring surveys. The basic requirements include preparation of a fugitive emissions monitoring plan for fugitive emissions components affected facilities within each company defined area, conducting initial and periodic monitoring, repair (including replacement) of any components found to be leaking, and verification (resurvey) that the repair was successful. You must also maintain records and submit annual reports of your fugitive emissions monitoring surveys.

Definitions

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.

Multi-wellhead only well site means a well site that contains two or more wellheads and no major production and processing 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.

Well sites and centralized production facilities with *major production and processing equipment* include facilities that have:

- One or more controlled storage vessels or tank batteries §60.5397b(g)(1)(iv)(A),
- One or more control devices §60.5397b(g)(1)(iv)(B),
- One or more natural gas-driven process controllers or pumps §60.5397b(g)(1)(iv)(C), or
- Two or more pieces of major production or processing equipment not listed above §60.5397b(g)(1)(iv)(D).

The fugitive emissions monitoring and repair program requires audible, visual, and olfactory (AVO) inspections at all site types and OGI or EPA Method 21 monitoring at some site types. Table 10-1 specifies the monitoring method and frequency according to the affected facility type.

Table 10-1. Fugitive Emissions Monitoring Method and Frequency

Fugitive Emissions Component Affected Facility	AVO inspection Frequency	OGI or EPA Method 21 Frequency
Single wellhead only well sites	Quarterly	Not required
Small well sites	Quarterly	Not required
Multi-wellhead only well sites	Quarterly	Semiannual
Well sites with major production and processing equipment	Bimonthly	Quarterly
Centralized production facilities	Bimonthly	Quarterly
Compressor Stations	Monthly	Quarterly

Figures 10-1 through 10-4 provide overviews of the emissions monitoring and repair requirements for single wellhead only well sites and small well sites, multi-wellhead only well sites, well sites with major production and processing equipment and centralized production facilities, and compressor stations, respectively.

For all well sites, fugitive monitoring continues until the site has been closed, including plugging the wells at the site and submitting a well closure report.

Figure 10-1. Fugitive Emissions Monitoring and Repair Requirements for Single Wellhead Only Well Sites and Small Well Sites

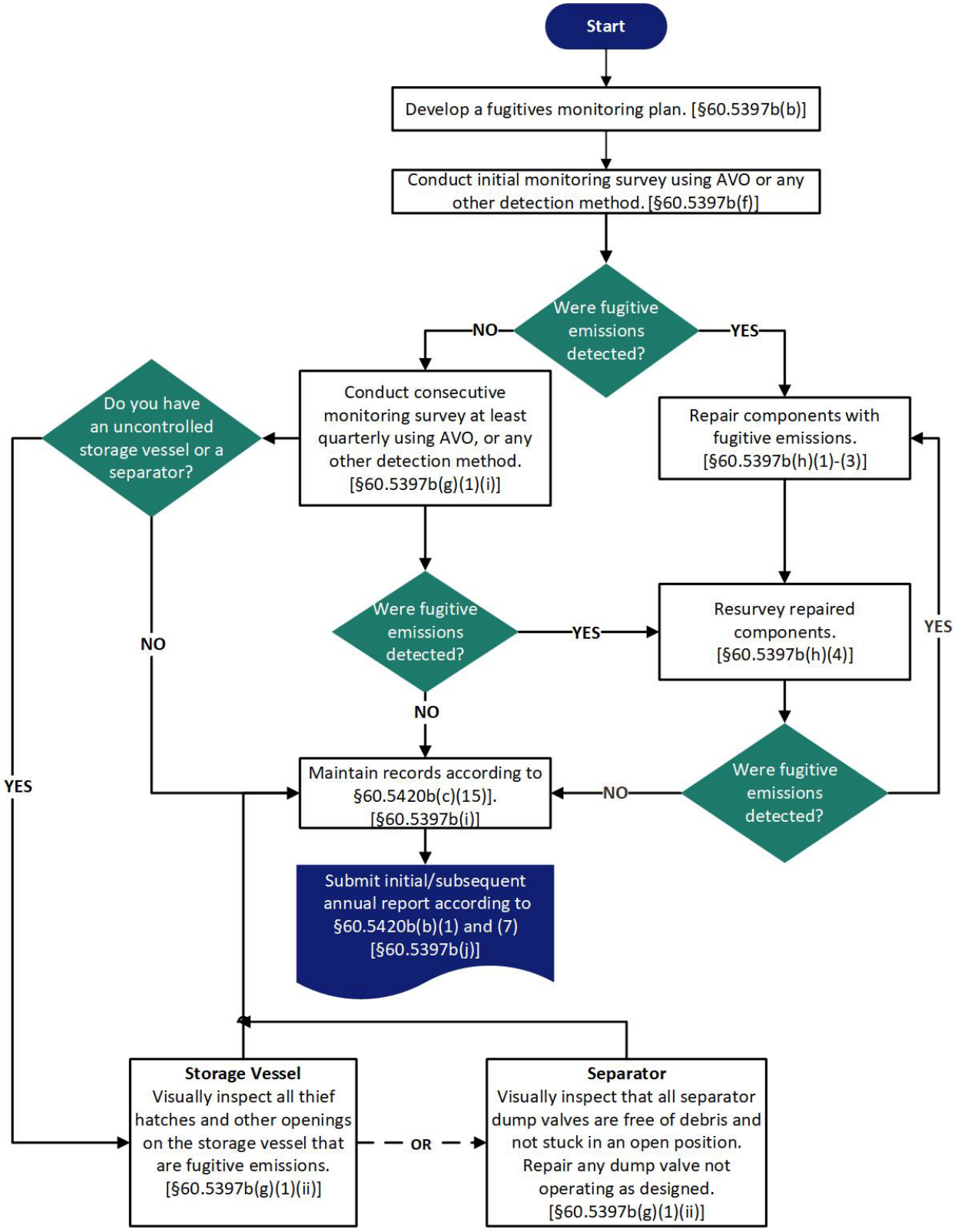


Figure 10-2. Fugitive Emissions Monitoring and Repair Requirements for Multi-Wellhead Only Well Sites

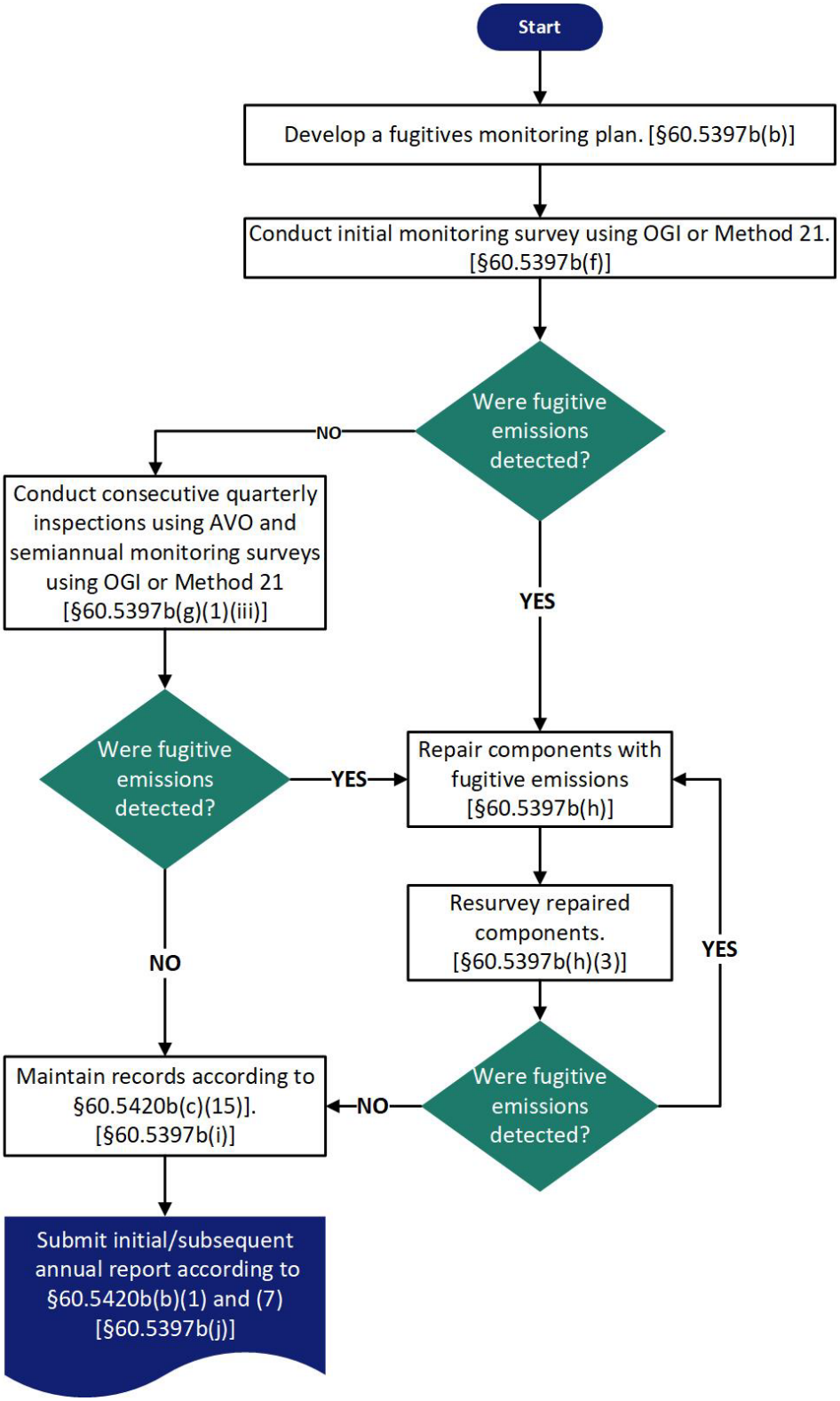


Figure 10-3. Fugitive Emissions Monitoring and Repair Requirements for Well Sites and Centralized Production Facilities with Major Production and Processing Equipment

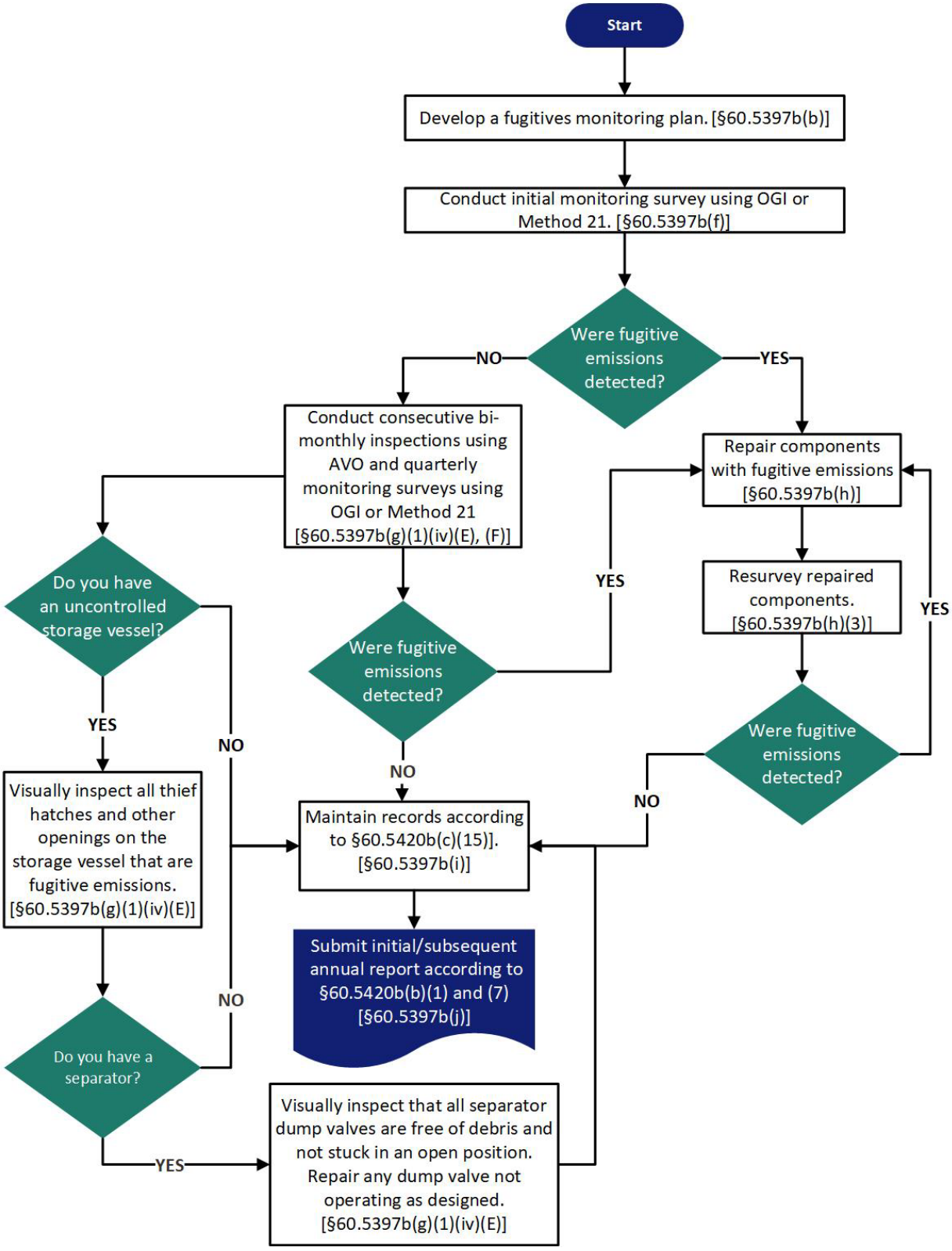
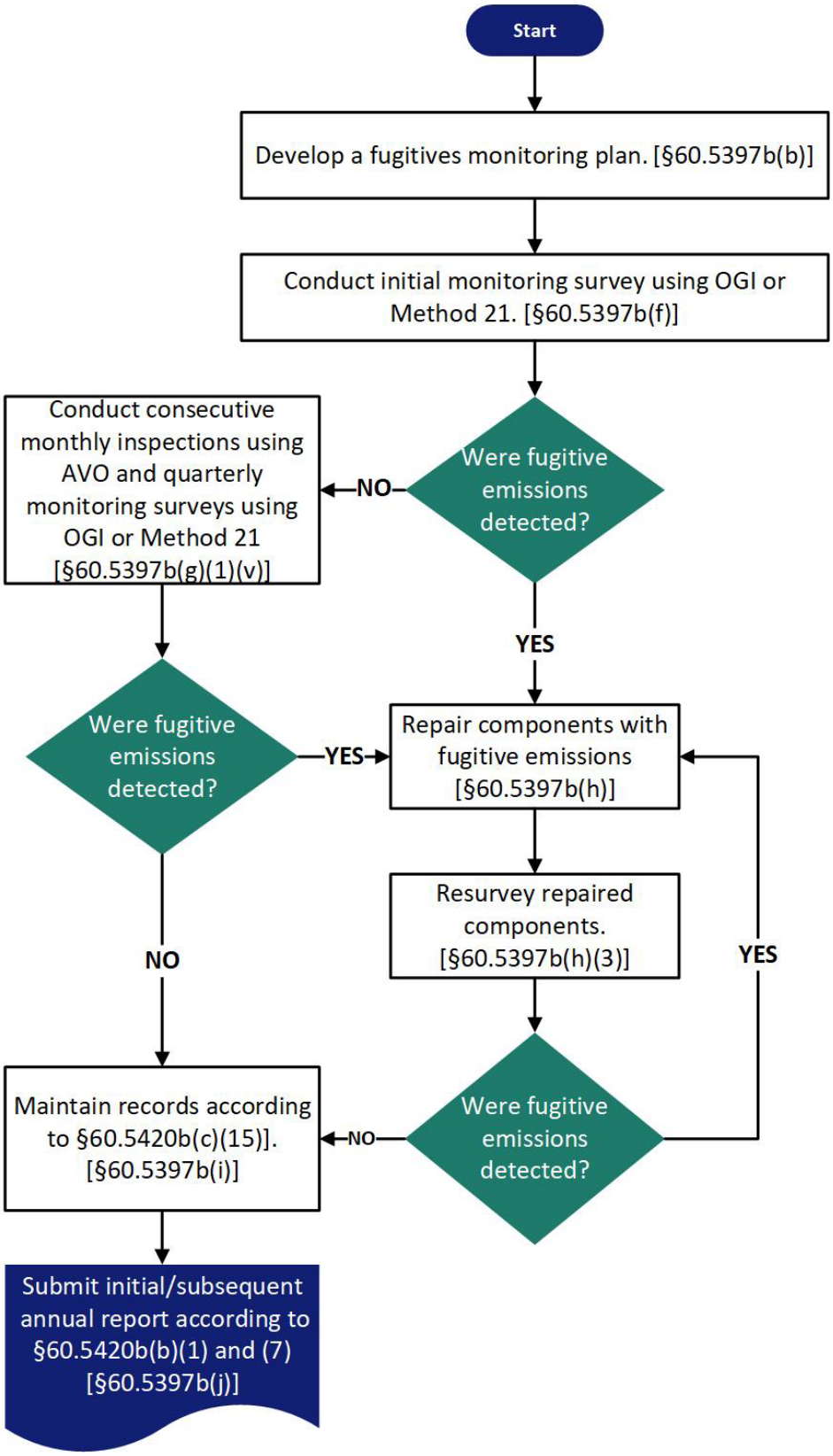


Figure 10-4. Fugitive Emissions Monitoring and Repair Requirements for Compressor Stations



The following repair schedule requirements apply when fugitive emissions have been detected following a monitoring survey:

- First attempt at repair:
  - If fugitive emissions were identified using AVO, a first attempt at repair must be made no later than 15 calendar days after detection of fugitive emissions.
  - If fugitive emissions were identified using OGI or Method 21, a first attempt at repair must be made no later than 30 calendar days after detection of fugitive emissions.
- Final repair:
  - Repair must be completed as soon as practicable.
  - If fugitive emissions were identified using AVO, final repair must be completed no later than 15 calendar days after the first attempt at repair.
  - If fugitive emissions were identified using OGI or Method 21, final repair must be completed 30 calendar days after the first attempt at repair.

Delay of repair following detection of fugitive emissions during a monitoring survey will be allowed if the following conditions are met:

- Delay of repair:
  - 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 or replacement must be completed during the next compressor station shutdown for maintenance, scheduled well shutdown, scheduled well shut-in, after a vent blowdown or within 2 years of detecting the fugitive emissions, whichever is earlier.

A vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel.

  - If the repair requires replacement of a fugitive emissions component or a part thereof, but the replacement cannot be acquired and installed within the specified repair timelines due to either valve assembly supplies had been sufficiently stocked but are depleted at the time of the required repair or a

replacement fugitive emissions component or a part thereof requires custom fabrication, 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 60.5397b(h)(3)(i).

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 as follows:

- Resurvey to confirm repair:
    - If fugitive emissions were identified using OGI or Method 21, the resurvey to verify repair must use either OGI or Method 21. If fugitive emissions were identified using AVO, resurvey may use AVO, OGI, or those Method 21.
        - A fugitive emissions component is repaired when the OGI instrument shows no indication of visible emissions.
        - A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppmv or when no soap bubbles are observed when the alternative screening procedures are used.
        - A fugitive emissions component is repaired when there are no indications of fugitive emissions using AVO methods.
    - 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 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).

10.3 When must I comply?

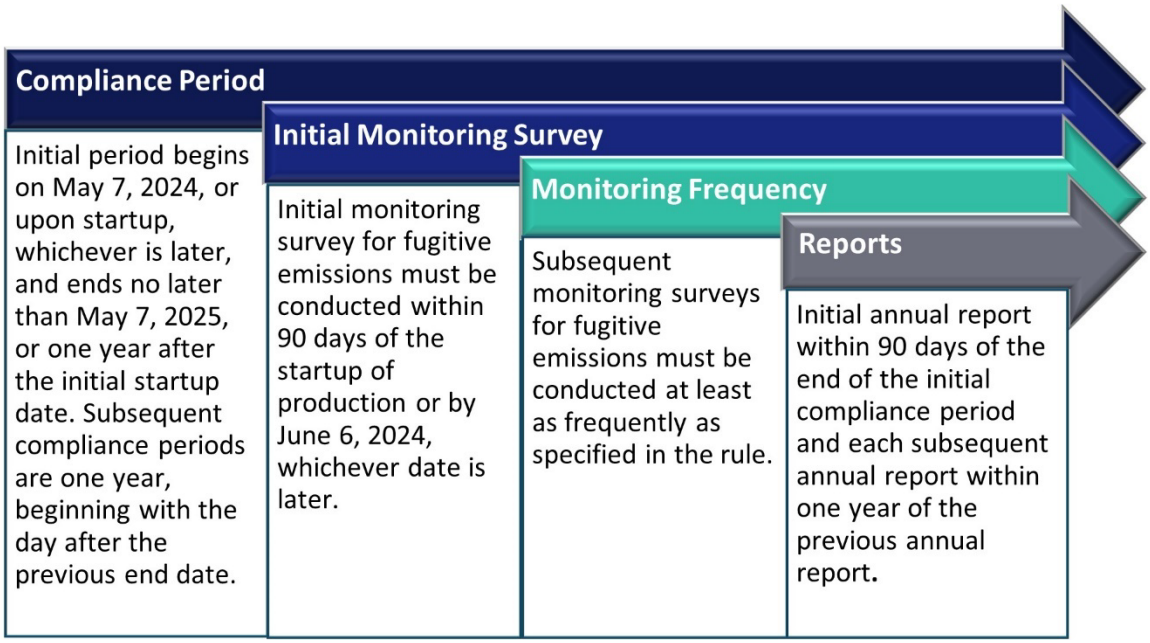
You must have your monitoring plan for each company-defined area in place and perform the initial monitoring survey within 90 days of the startup of production for new, modified or reconstructed well sites or within 90 days of the startup of a new, modified, or reconstructed or by June 6, 2024, whichever is later.

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.

For multi-wellhead well site conducting OGI and Method 21 semiannual monitoring surveys, consecutive semiannual surveys must be conducted at least 4 months apart and no more than 7 months apart.

For well sites and centralized production facilities with major production or processing facilities and compressor stations conducting quarterly OGI or Method 21 monitoring surveys, consecutive quarterly surveys must be conducted at least 60 days apart. Note that quarterly monitoring surveys mean conducting surveys every 3 calendar months.

Figure 10-5. Compliance Schedule for Fugitive Components Affected Facilities



10.4 What other inspections are required?

In conjunction with the periodic fugitive emissions monitoring surveys using either AVO, OGI or Method 21, the following inspection requirements must also be met for fugitive emissions components affected facilities that have storage vessels or separators.

Figure 10-6. Other Inspection Requirements for Fugitive Emissions Components Affected Facilities

VISUAL INSPECTION REQUIREMENTS IN CONJUNCTION WITH MONITORING SURVEY §60.5397b(g)(1)(ii) §60.5397b(g)(1)(iv)(E)	
	Visually inspect all thief hatches and other openings on the storage vessel.
	Ensure they are 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.
	Visually inspect all separator dump valves.
	Ensure the dump valve is free of debris and not stuck in an open position.
	Any dump valve not operating as designed must be repaired.

10.5 What testing or monitoring is required?

There are no testing requirements associated with these standards. The fugitive emissions monitoring and repair requirements described above in section 10.2 includes all monitoring required by the rule for the fugitive emissions components affected facilities at well sites, centralized production facilities and compressor stations, as well as the inspection requirements described in section 10.4.

The NSPS OOOOb includes a process for the Administrator to approve the use of innovative technology for monitoring fugitive emissions components affected facilities at well sites, centralized production facilities and compressor stations using an alternative means of emission limitation. [§60.5398b and §60.5399b]

10.6 What, when and to whom must I report?

In addition to the information outlined in 1.4.3 (Requirements applicable to all affected facilities) above, you must include the information outlined in §60.5420b(b)(9) in your annual report for your fugitive emissions components affected facility.

10.7 What records must I keep?

You must maintain the records for each fugitive emissions monitoring survey. Specifically, you must maintain the records outlined in §60.5420b(c)(14), as applicable, for the fugitive emissions components affected facility located at well site, centralized production facility or compressor station vessel affected facilities within each company-defined area.

The records that must be kept for the fugitive emissions components affected facilities located at well sites, centralized production facilities and compressor stations are the same. You must maintain a copy of the monitoring plan either onsite or at the nearest field office. [§60.5420b(c)]

In addition to the monitoring plan, you must maintain records of each fugitive emissions monitoring survey conducted either onsite or at the nearest field office for at least five years. Also, for the fugitive emissions components affected facilities, if a monitoring survey is waived under §60.5397b(g)(4), you must maintain records of the average calendar month temperature, including the source of the information, for each calendar month of the quarterly monitoring period for which the monitoring survey was waived. [§60.5420a(c)(14)]

11.0 Alternative GHG and VOC Standards when Using Alternative Technology

11.1 What is the Alternative Test Method for Methane Detection Technology Program?

In lieu of periodic monitoring required under §60.5397b using OGI and Method 21, subpart OOOOb includes alternative provisions for the use of advanced technologies to detect fugitive methane emissions and emissions from covers and CVS through either periodic screenings or continuous monitoring. Under the provisions of §60.5398b, owners/operators may request the use of an alternative methane detection technology. Approval of the alternative technology will include consideration of both the measurement technology and the standard protocol for its operation. If you use an alternative methane detection technology, you must comply with the alternative GHG and VOC standards for fugitive emissions components affected facilities in §60.5398b rather than the requirements for those affected facilities in §60.5397b.

Any *alternative test method* for methane detection technology used to meet the alternative standards under §60.5398b must be approved by the Administrator as specified in §60.5398b(d).

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***.

11.2 How do I determine if my facility can use the Alternative Standards?

The owner/operator of any facility subject to the fugitive emissions standards of §60.5397b and the continuous inspection and monitoring requirements for covers and CVSs of §60.5416b can choose to use an alternative fugitive methane detection method and comply instead with the requirements of §60.5398b.

If you choose to use an alternative fugitive methane detection method under §60.5398b, you must do the following:

- Submit the notification as specified in §60.5398b(a).

- If you choose to use a periodic screening method for fugitive methane emissions detection, you must meet the requirements in §60.5398b(b).
- If you choose to use a continuous monitoring system for fugitive methane emissions detection, you must meet the requirements in §60.5398b(c).
- The alternative methane detection technology must be approved by the EPA in accordance with the requirements in §60.5398b(d).

A summary of the requirements for owners/operators who choose to comply with the fugitive emissions standards using an alternative methane detection technology is provided in sections 11.3 through 11.7 of this guide.

Once you have implemented the alternative standards under §60.5398b, you must continue to comply with the alternative standards.

11.3 How do I comply?

11.3.1 Periodic Screening

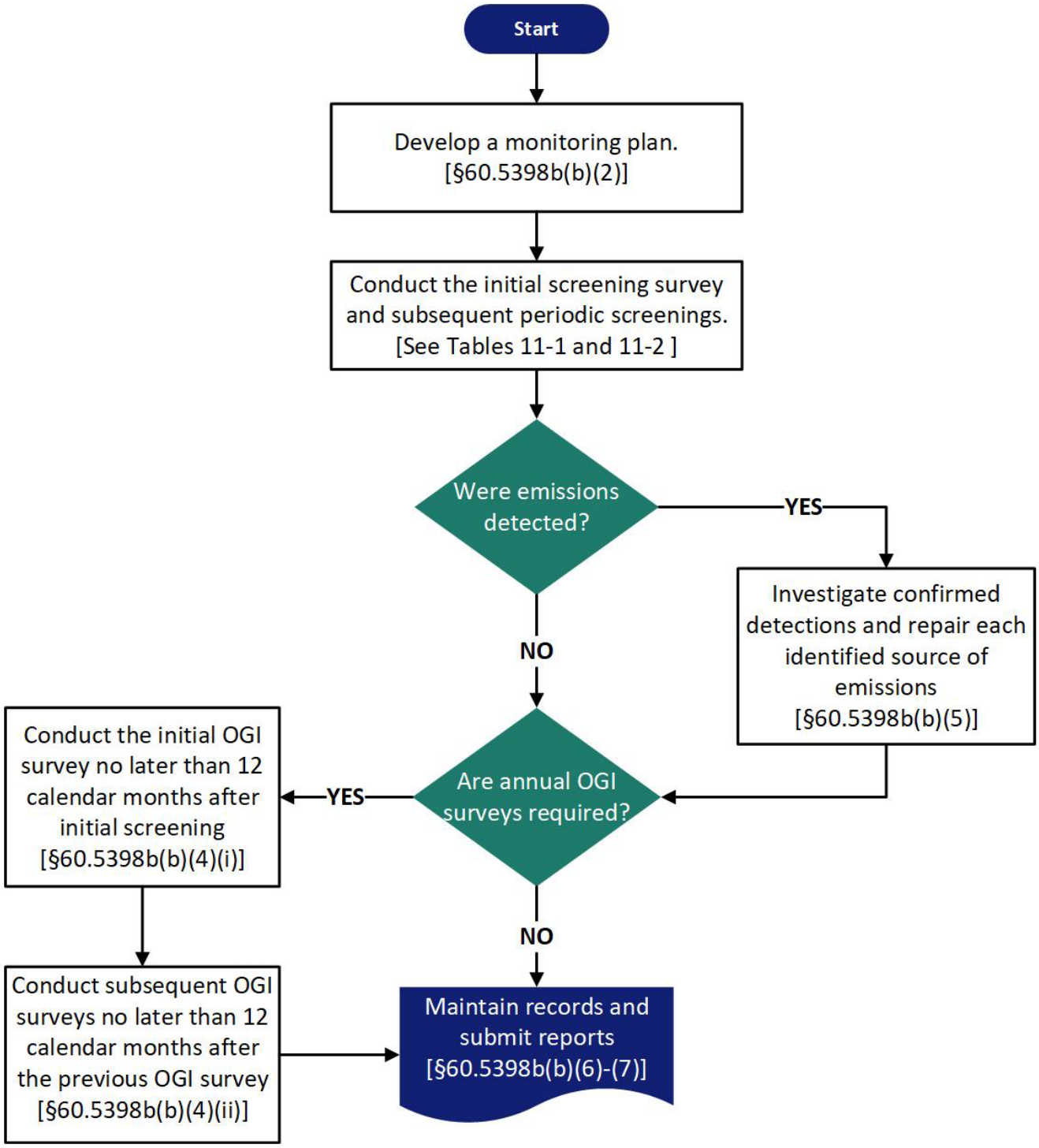
If you choose to use periodic screenings to demonstrate compliance with the alternative standards of §60.5398b, you must comply with the requirements summarized below. [§60.5398b(b)(1) through (6)]

1. Use alternative test method(s) approved §60.5398b(d) to conduct periodic screenings (see Figure 11-1 [Compliance Requirements for Periodic Screening] of this guide).
2. Develop a monitoring plan.
    a. Plan must include the collection of fugitive emissions components, covers, and CVSs at each site where you will use periodic screenings to demonstrate compliance.
    b. Plan may be site-specific or may include multiple sites that you own or operate.
    c. Plan must contain the information specified in §60.5398b(b)(2)(i) through (ix).
3. Conduct initial screening of your site according to the timeframes specified in §60.5398b(b)(3)(i) through (v).
4. If you are required to conduct an annual OGI survey, conduct OGI surveys according to the schedule in paragraphs §60.5398b(b)(4)(i) through (iv) (see Table 11-1 [Alternative Technology Periodic Screening Frequency: Sources Subject to AVO Inspections with Quarterly OGI or EPA Method 21 Monitoring under §60.5397b(g)] of this guide).

5. Investigate confirmed detections of emissions from periodic screening events and repair each identified source of emissions in accordance with §60.5398b(b)(5)(i) through (vii).
    a. Results of the periodic screening are due no later than 5 calendar days after the screening event occurs.
    b. If the confirmed detection was based on an alternative test method with a facility-level spatial resolution, survey the entire fugitive emissions components affected facility and inspect all covers and CVS visually and with OGI or Method 21.
    c. If the confirmed detection was based on an alternative test method with an area-level spatial resolution, survey fugitive emissions components located within a 4-meter radius of the location of confirmed detection and if the confirmed detection occurred in the portion of a site that contains a storage vessel or a CVS, inspect all covers and all CVS that are connected to all storage vessels and CVS that are within a 2-meter radius of the confirmed detection location.
    d. If a confirmed detection was based on an alternative test method with a component-level spatial resolution, survey fugitive emissions components located within a 1-meter radius of the location of the confirmed detection and if the confirmed detection occurred in the portion of a site that contains a storage vessel or a CVS, inspect all covers and all CVS that are connected to all storage vessels and CVS that are within a 0.5-meter radius of the confirmed detection location.
6. Maintain records as specified in §60.5420b(c)(4) through (c)(7), (c)(14) and (c)(15), and §60.5424b(c).
7. Submit reports as specified in §60.5424b.

Figure 11-1 (Compliance Requirements for Periodic Screening) provides an overview of the requirements for owners and operators who choose to comply with the alternative standards using periodic screening.

Figure 11-1. Compliance Requirements for Periodic Screening



If you choose to use periodic screenings to demonstrate compliance with the alternative standards of §60.5398b, you must choose the appropriate periodic screening frequency based on the minimum aggregate detection threshold of the screening method. Tables 11-1

(Alternative Technology Periodic Screening Frequency: Sources Subject to AVO Inspections with Quarterly OGI or EPA Method 21 Monitoring under §60.5397b(g)) and 11-2 (Alternative Technology Periodic Screening Frequency: Sources Subject to AVO Inspections and/or Semiannual OGI or EPA Method 21 Monitoring under §60.5397b(g)) of this guide show the required periodic screening frequencies and whether you must also conduct an annual fugitive emissions survey using OGI.

Table 11-1. Alternative Technology Periodic Screening Frequency: Sources Subject to AVO Inspections with Quarterly OGI or EPA Method 21 Monitoring under §60.5397b(g)

Minimum Periodic Screening Frequency [a,b,c]	Minimum Detection Threshold of Screening Technology [d]	Annual OGI Survey Required?
Quarterly	≤1 kg/hr	No
Bimonthly	≤2 kg/hr	No
Bimonthly plus Annual OGI	≤10 kg/hr	Yes
Monthly	≤5 kg/hr	No
Monthly plus Annual OGI	≤15 kg/hr	Yes

a. Based on the required frequency for conducting monitoring surveys in §60.5397b(g)(1)(i) through (v).
b. 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.
c. You may replace one or more individual periodic screening events with an OGI survey. The OGI survey must be conducted according to the requirements outlined in §60.5397b.
d. The minimum detection threshold of the screening technology is based on a probability of detection of 90 percent.

Table 11-2. Alternative Technology Periodic Screening Frequency: Sources Subject to AVO Inspections and/or Semiannual OGI or EPA Method 21 Monitoring under §60.5397b(g)

Minimum Periodic Screening Frequency [a,b,c]	Minimum Detection Threshold of Screening Technology [d]	Annual OGI Survey Required?
Semiannual	≤1 kg/hr	No
Triannual	≤2 kg/hr	No
Triannual plus Annual OGI	≤10 kg/hr	Yes
Quarterly	≤5 kg/hr	No
Quarterly plus Annual OGI	≤15 kg/hr	Yes
Bimonthly	≤15 kg/hr	No

a. Based on the required frequency for conducting monitoring surveys in §60.5397b(g)(1)(i) through (v).
b. 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.
c. You may replace one or more individual periodic screening events with an OGI survey. The OGI survey must be conducted according to the requirements outlined in §60.5397b.
d. The minimum detection threshold of the screening technology is based on a probability of detection of 90 percent.

11.3.2 Continuous Monitoring

Owners and operators who choose to use continuous monitoring, to demonstrate compliance with the alternative standards of §60.5398b, must meet the following requirements for operating continuous monitoring systems including using advanced methane monitoring technology approved by the EPA for this purpose under §60.5398b(d):

- 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.
- 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.
- 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 §60.5398b(c)(1)(ii).
- The continuous monitoring system must continuously collect data as specified in §60.5398b(c)(1), except as specified in §60.5398b(c)(1)(iv)(A) through (D) of subpart OOOOb.

Continuous monitoring means a methane monitoring system that has the ability to determine and record a valid methane mass emissions rate (or equivalent) from affected facilities at least once for every 12-hour block.

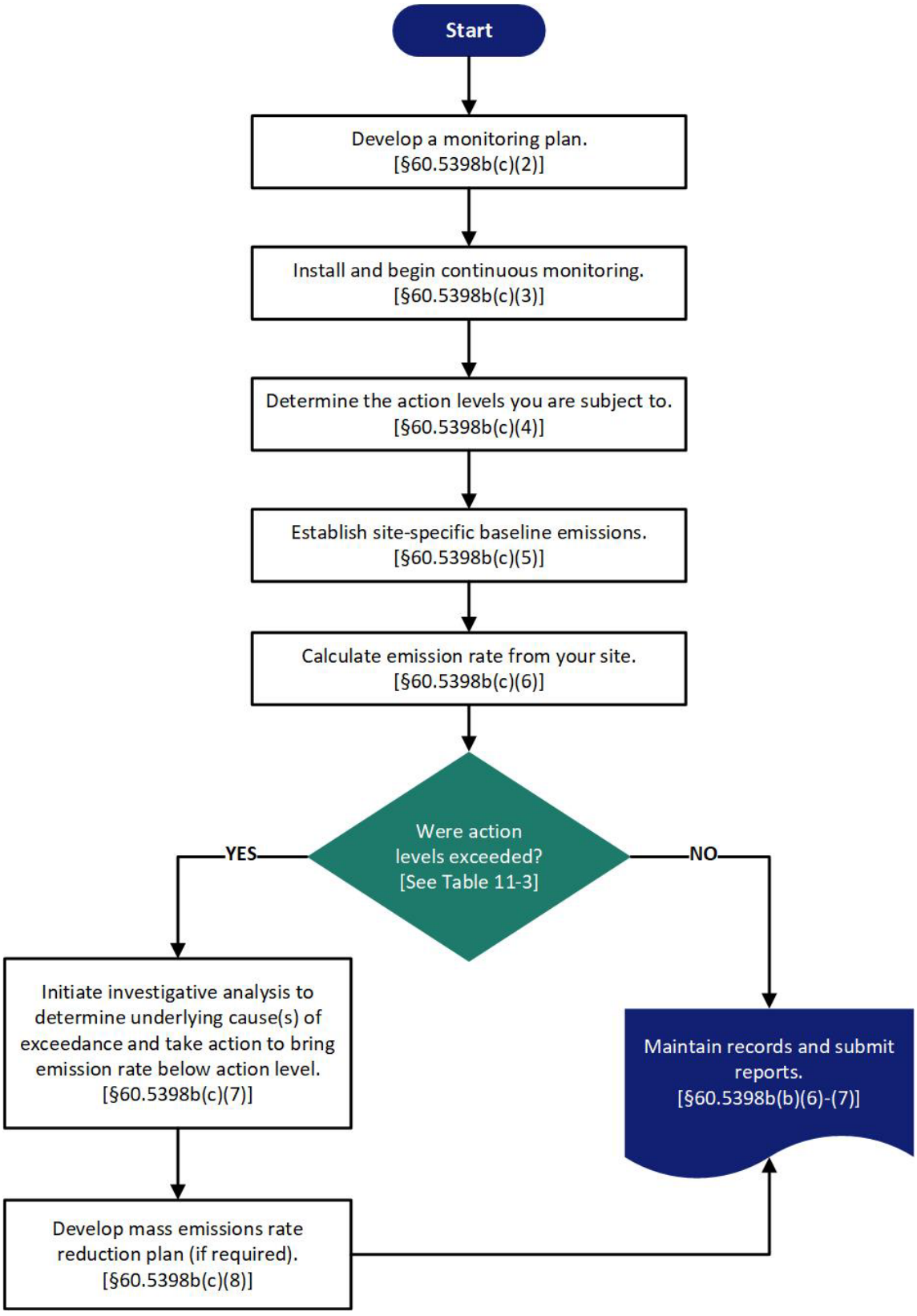
If you choose to use continuous monitoring to demonstrate compliance with the alternative standards of §60.5398b, you must comply with the requirements summarized below. [§60.5398b(c)(1) through (9)]

1. Use alternative test method(s) approved §60.5398b(d) to conduct periodic screenings. (see Figure 11-2 [Compliance Requirements for Continuous Monitoring] of this guide).
2. Develop a monitoring plan.
    a. Plan must include the collection of fugitive emissions components, covers, and CVSs at each site where you will use continuous monitoring to demonstrate compliance.
    b. Plan must contain the information specified in §60.5398b(c)(2)(i) through (xii).
3. Install and begin conducting monitoring according to §60.5398b(c)(3)(i) through (v).
4. Comply with the action-levels in §60.5398b(c)(4)(i) and (ii) (see Table 11-3 [Alternative Technology Continuous Monitoring Action-Levels] of this guide).

5. Establish site-specific baseline emissions upon initial installation and activation of your continuous monitoring system.
6. Calculate the emission rate from your site according to §60.5398b(c)(6)(i) through (iii). Compare the emission rate to the appropriate action levels for your site (see Table 11-3 [Alternative Technology Continuous Monitoring Action-Levels] of this guide).
7. Initiate investigative analysis within 5 days of action-level exceedance to determine underlying cause and actions to be taken to bring the mass emission rate below the action level.
    a. 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 any 7-day rolling average action level.
    b. 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 any 90-day rolling average action level.
8. Develop a mass emission rate reduction plan if you meet any of the criteria in §60.5398b(c)(8)(i) through (iii).
9. Maintain records as specified in §60.5420b(c)(4) through (c)(7), (c)(14) and (c)(15), and §60.5424b(e).
10. Submit reports as specified in §60.5420b(b)(1) and (b)(4) through (10) and §60.5424b.

Figure 11-2 (Compliance Requirements for Continuous Monitoring) provides an overview of the requirements for owners and operators who choose to comply with the alternative standards using continuous monitoring.

Figure 11-2. Compliance Requirements for Continuous Monitoring



If you choose to use continuous monitoring to demonstrate compliance with the alternative standards of §60.5398b, you must choose the appropriate 90-day and 7-day rolling average action-level based on the type of fugitive emissions component affected facility you have. Table 11-3 (Alternative Technology Continuous Monitoring Action-Levels) of this guide shows the action levels for each type of affected facility.

Table 11-3. Alternative Technology Continuous Monitoring Action-Levels

Fugitive Emissions Component Affected Facility	90-day Rolling Average Action-Level [a]	7-day Rolling Average Action Level [a]
Wellhead only well site	1.2 kg/hr (2.6 lb/hr)	15 kg/hr (34 lb/hr)
Small well sites	1.6 kg/hr (3.6 lb/hr)	21 kg/hr (46 lb/hr)
Well sites with major production and processing equipment	1.6 kg/hr (3.6 lb/hr)	21 kg/hr (46 lb/hr
Centralized production facilities	1.6 kg/hr (3.6 lb/hr)	21 kg/hr (46 lb/hr)
Compressor stations	1.6 kg/hr (3.6 lb/hr)	21 kg/hr (46 lb/hr)

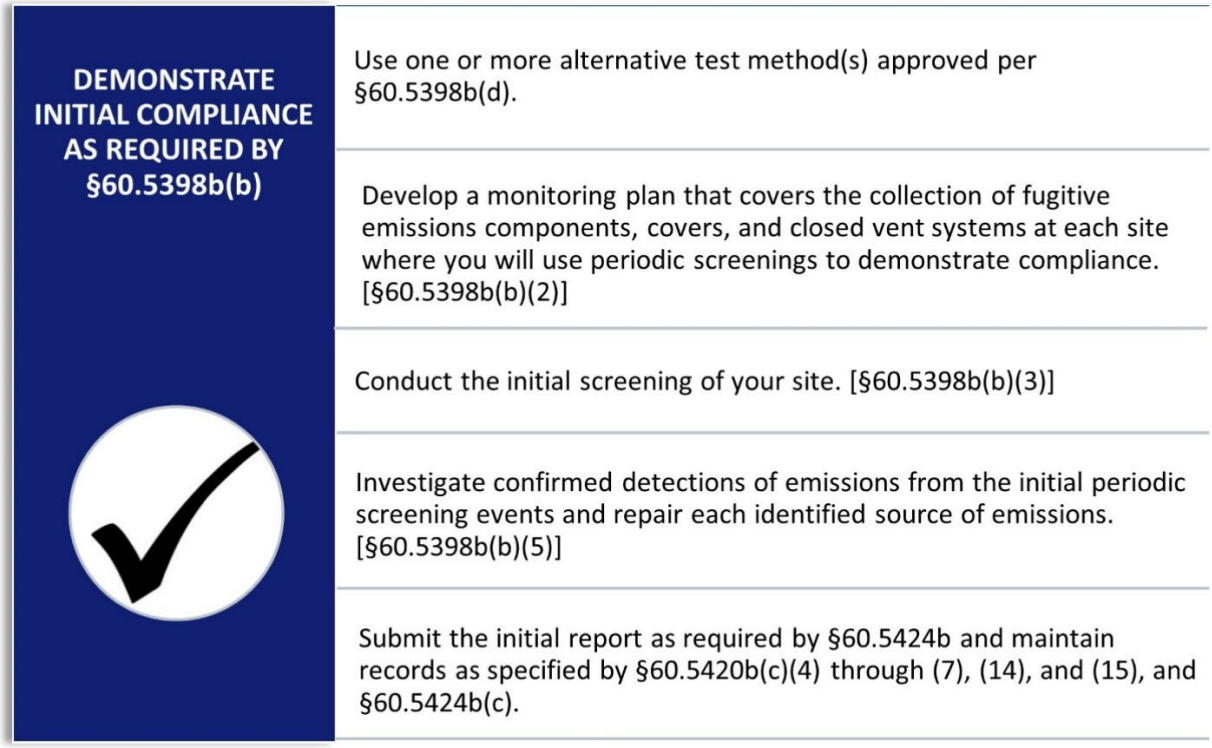
a. The rolling average is the amount of methane over site-specific baseline emissions.

11.4 How do I demonstrate initial and continuous compliance?

11.4.1 Periodic Screening

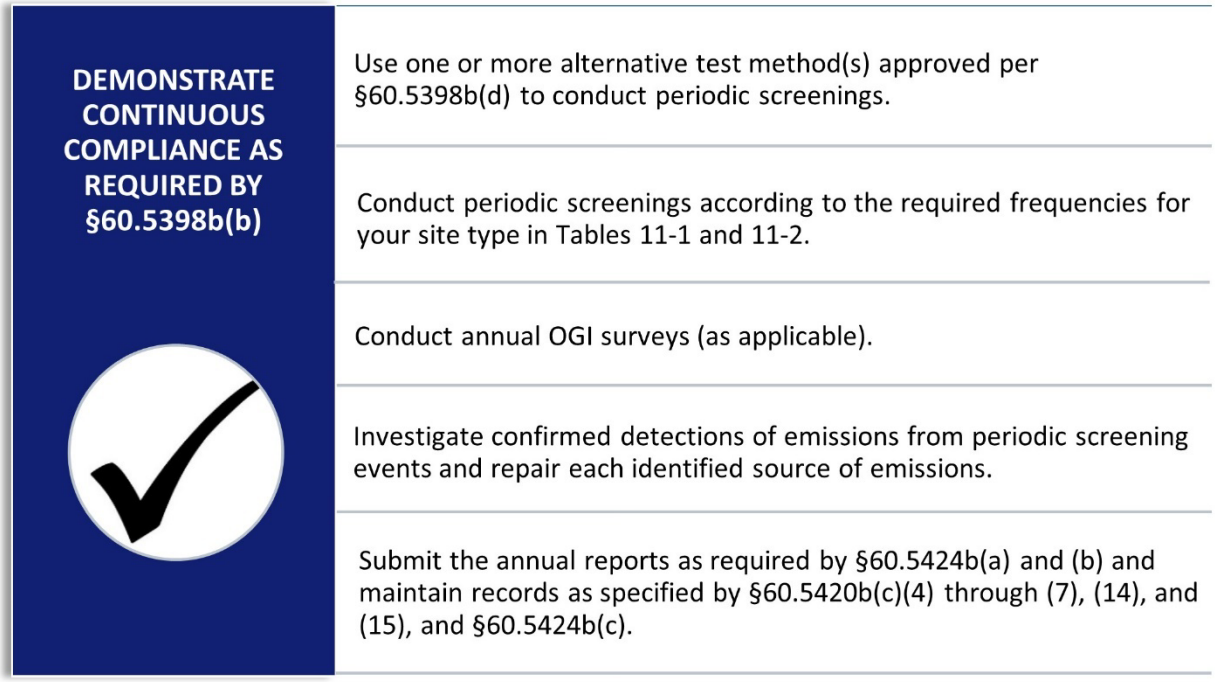
To demonstrate initial compliance for your facility complying with periodic screening, please refer to the summary overview of requirements in Figure 11-3 (Initial Compliance Requirements for Alternative Standards when using Periodic Screening).

Figure 11-3. Initial Compliance Requirements for Alternative Standards when Using Periodic Screening



To demonstrate continuous compliance for your facility complying with periodic screening, please refer to the summary overview of requirements in Figure 11-4 (Continuous Compliance Requirements for Alternative Standards when Using Periodic Screening).

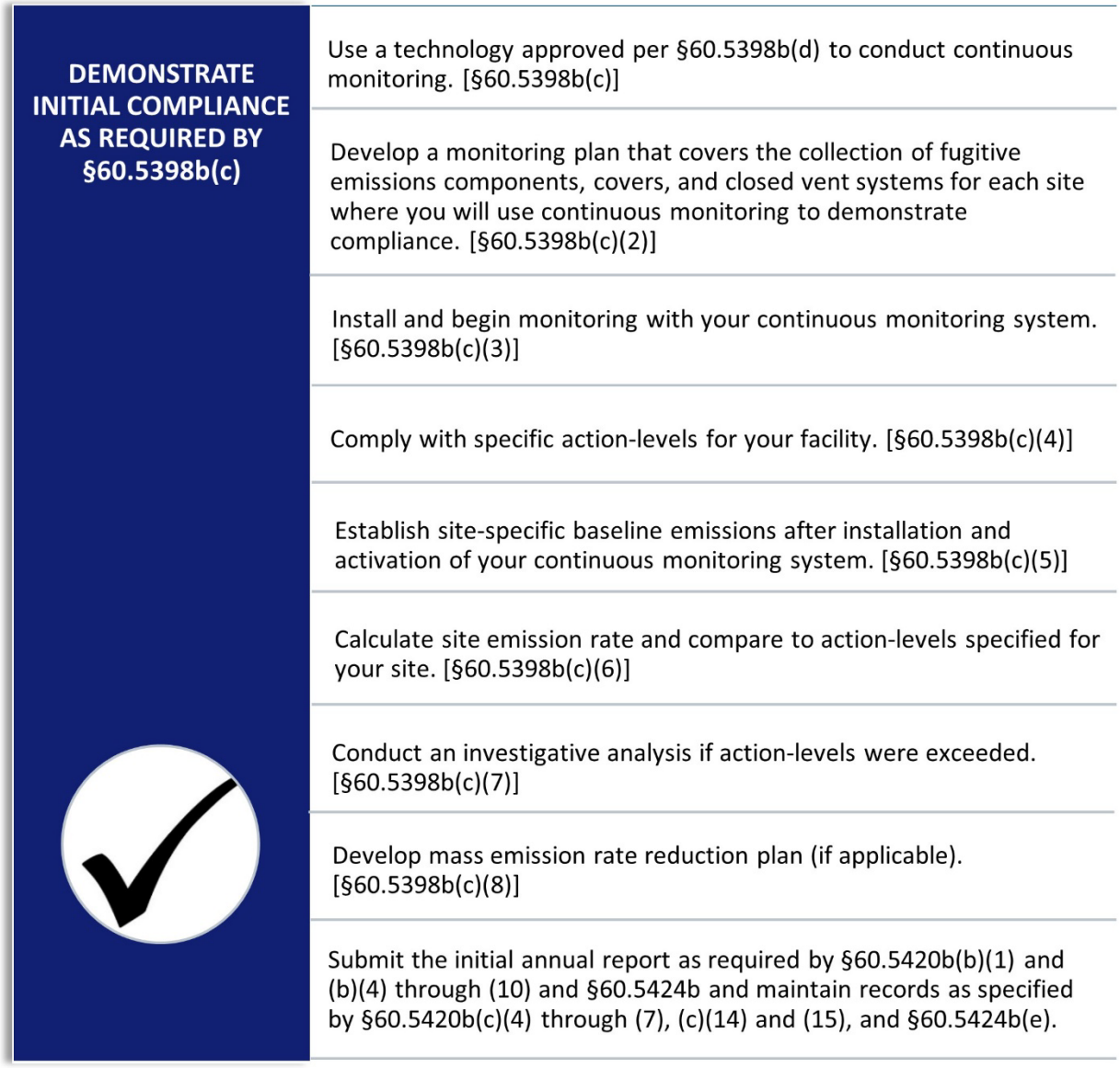
Figure 11-4. Continuous Compliance Requirements for Alternative Standards when Using Periodic Screening



11.4.2 Continuous Monitoring

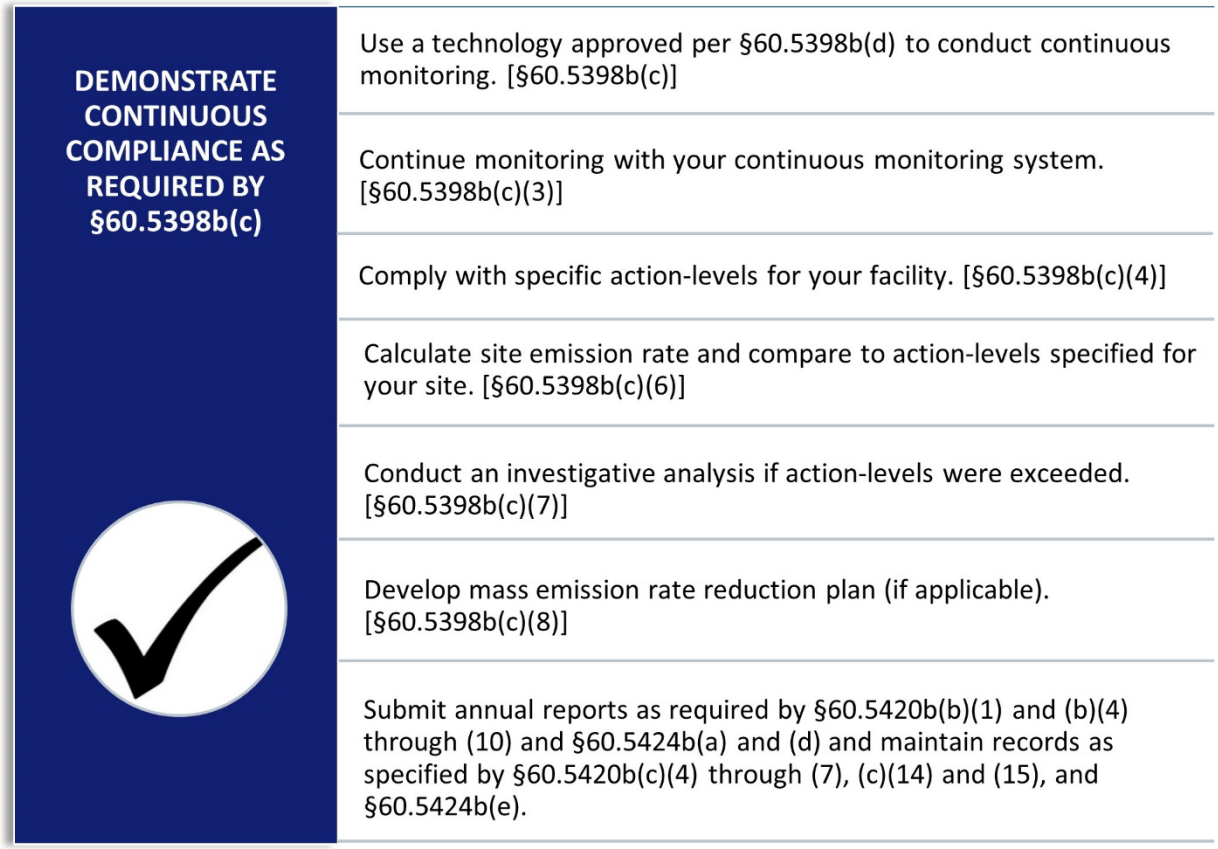
To demonstrate initial compliance for your facility complying with continuous monitoring, please refer to the summary overview of requirements in Figure 11-5 (Initial Compliance Requirements for Alternative Standards when Using Continuous Monitoring).

Figure 11-5. Initial Compliance Requirements for Alternative Standards when Using Continuous Monitoring



To demonstrate continuous compliance for your facility complying with continuous monitoring, please refer to the summary overview of requirements in Figure 11-6 (Continuous Compliance Requirements for Alternative Standards when Using Continuous Monitoring).

Figure 11-6. Continuous Compliance Requirements for Alternative Standards when Using Continuous Monitoring

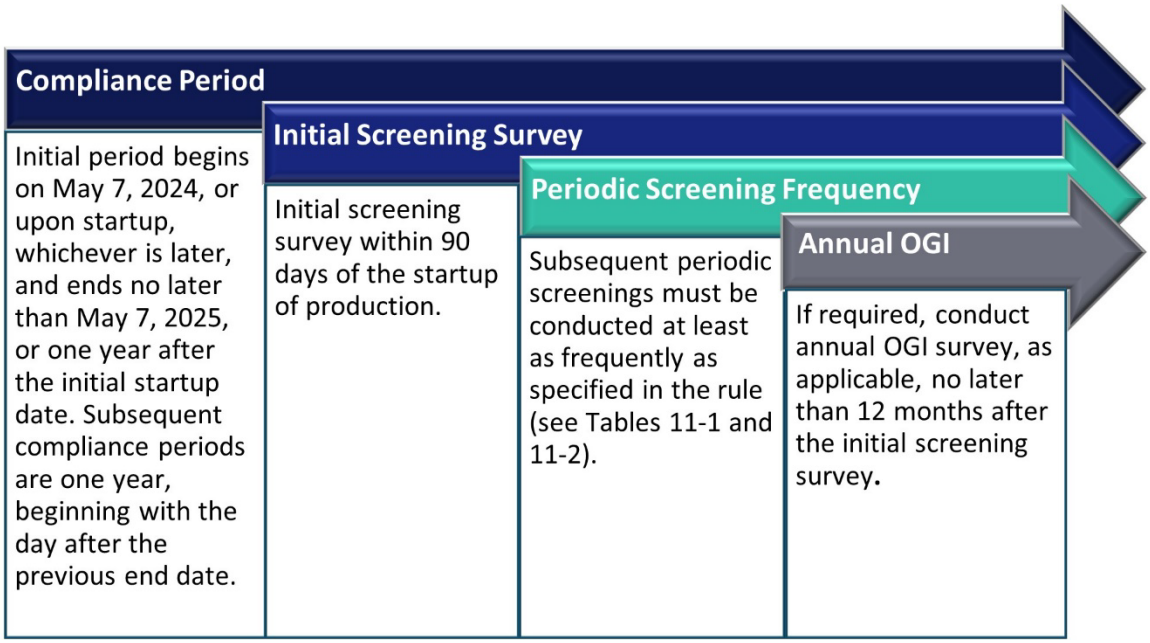


11.5 When must I comply?

11.5.1 Periodic Screening

Figure 11-7 (Compliance Schedule for Periodic Screening) provides a summary overview of the compliance schedule for your facility complying with periodic screening.

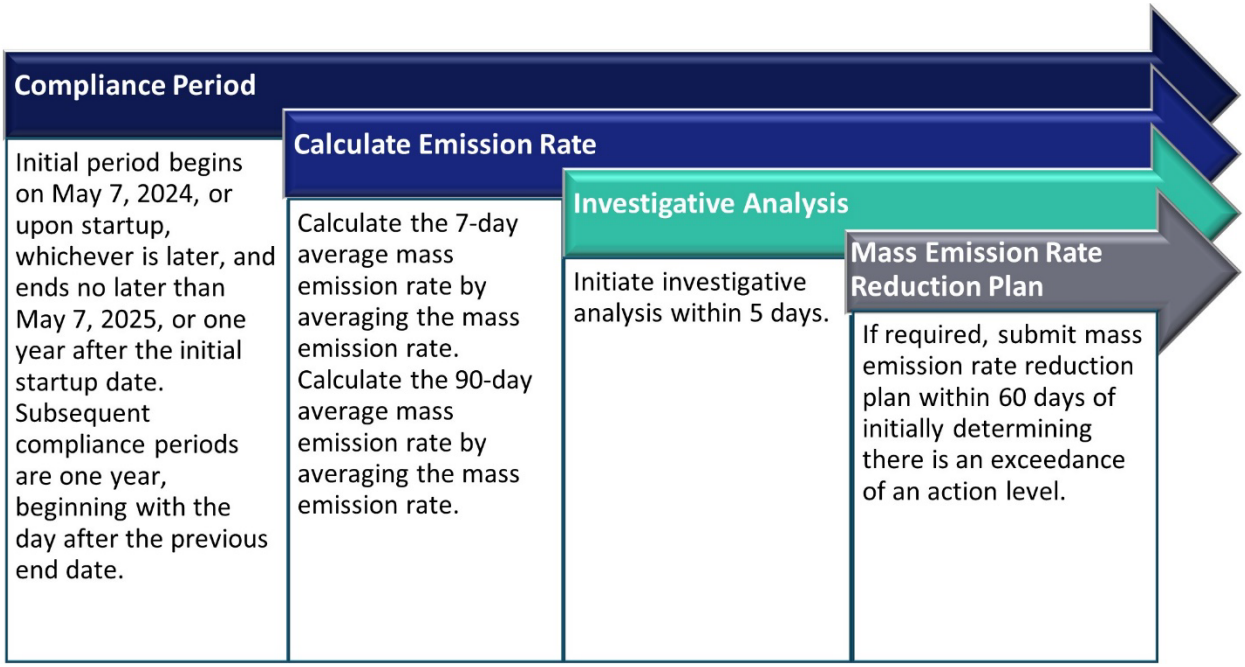
Figure 11-7. Compliance Schedule for Periodic Screening



11.5.2 Continuous Monitoring

Figure 11-8 (Compliance Schedule for Continuous Monitoring) provides a summary overview of the compliance schedule for your facility complying with continuous monitoring.

Figure 11-8. Compliance Schedule for Continuous Monitoring



11.6 What, when, and to whom must I report?

If you choose to use an alternative standard under §60.5398b, either through periodic screening according to §60.5398b(b) or through continuous monitoring according to §60.5398b(c), 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).

11.6.1 Periodic Screening

If you choose to comply with the alternative standard through periodic screening according to §60.5398b(b), you must submit the information in §60.5424b(b)(1)-(6) in the annual report required by § 60.5420b(b)(4) through (11).

11.6.2 Continuous Monitoring

If you choose to comply with the alternative standard through continuous monitoring according to §60.5398b(c), you must submit the information in §60.5424b(d)(1)-(6) in the annual report required by §60.5420b(b)(4) through (11).

11.7 What records must I keep?

11.7.1 Periodic Screening

If you choose to comply with periodic screening requirements in §60.5398b(b), you must maintain the information described in §60.5424b(c).

11.7.2 Continuous Monitoring

If you choose to comply with continuous monitoring requirements in §60.5398b(c), you must maintain the information described in §60.5424b(e).

12.0 GHG and VOC Standards for Equipment Leaks at Onshore Natural Gas Processing Plants

12.1 How do I determine if my group of equipment is an affected facility?

The GHG and VOC standards for equipment leaks at natural gas processing plants apply to the group of all equipment within a process unit that is located at an onshore natural gas processing plant and that commenced construction, reconstruction, or modification after December 6, 2022. Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit that is located at an onshore natural gas processing plant is also an affected facility. [§60.5365b(f)]

Each piece of equipment is presumed to have the potential to emit methane or VOC unless you demonstrate 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 of 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 as specified in §60.17). [§§60.5400b(a)(2) and 60.5401b(a)(2)]

Definitions

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.

Liquified 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.

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.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

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.

Exceptions and Exemptions

The rule includes the following exceptions and exemptions to the standard:

- The addition or replacement of equipment at an existing facility for the purpose of process improvement that is accomplished without a capital expenditure is not by itself considered a modification and therefore, is not subject to the rule. [§60.5365b(f)(1)]
- Equipment not located at the onshore natural gas processing plant site is exempt from the equipment leak provisions of the rule. [§60.5365b(f)(2)]
- Pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor or light liquid service, and connectors in gas/vapor service or 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 routine OGI or Method 21 monitoring. [§60.5402b(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 within a process unit that is located in the ANS are exempt from the routine OGI or Method 21 monitoring requirements, but pressure relief devices must be re-monitored after a pressure release. [§60.5402b(c)]
- Equipment that is in vacuum service, except connectors in gas/vapor and light liquid service, is excluded from the requirements, provided that records are kept identifying the equipment in vacuum service. [§60.5402b(e)]
- Equipment that is designed as having the potential to emit methane or VOC less than 300 hr/yr is excluded from the requirements, provided that records are kept identifying the equipment and one of the following conditions apply:
    - The equipment has the potential to emit methane or VOC only during startup and shutdown.
    - The equipment has the potential to emit methane or VOC only during process malfunctions or other emergencies.
    - The equipment is backup equipment that has the potential to emit methane or VOC only when the primary equipment is out of service.

[§60.5402b(f)]

12.2 How do I comply?

You must conduct monitoring and repair leaks.

- You must conduct bimonthly (i.e., once every other month) OGI monitoring in accordance with 40 CFR part 60, appendix K (See Appendix B of this document) to detect equipment leaks from pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor or light liquid service, connectors in gas/vapor or light liquid service, and CVS, for each piece of equipment that has the PTE methane or VOC. [§60.5400b(a) through (d)]
    - You must conduct additional weekly visual inspections for pumps in light liquid service. [§60.5400b(a) and §60.5400b(c)]
    - You must monitor each pressure relief device within 5 calendar days of each pressure release. [§60.5400b(a) and §60.5400b(d)]
- Open-ended valves and lines must be equipped with a cap, blind flange, plug, or a second valve which seals 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 (except open-ended lines or valves in emergency shutdown systems and open-ended lines or

valves that would autocatalytically polymerize or would prevent a safety incident). [§60.5400b(a) and (e)]

- Pumps, valves and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service must be monitored using AVO or any other detection method. [§60.5400b(a) and §60.5400b(g)]
- For requirements for CVS which are used to comply with the equipment leak provisions, see section 14.0 (Covers, Closed Vent Systems, and Control Devices) of this guide. [§60.5400b(a) and §60.5400b(f)]

As an alternative to the bimonthly OGI monitoring, EPA Method 21 may be used to detect leaks from the same equipment at frequencies specific to the process unit equipment type. [§60.5401b]

See Figure 12-1 (Subpart OOOOb Requirements for Process Unit Equipment Affected Facilities Using OGI [§60.5400b]) for a summary overview of the monitoring requirements when using OGI. See Figure 12-2 (Subpart OOOOb Requirements for Process Unit Equipment Affected Facilities Using Method 21 [§60.5401b]) for a summary overview of the requirements when using Method 21.

You may apply to the Administrator for permission to use an alternative means of emissions limitation (AMEL) that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in this subpart. [§§60.5400b(a)(1) and 60.5401b(a)(1)]

Figure 12-1. Requirements for Process Unit Equipment Affected Facilities Using OGI [§60.5400b]

a. Pressure relief devices at a non-fractionating plant where the non-fractionating plant is monitored only by non-plant personnel that are not onsite are not subject to the 5-day post-pressure release monitoring requirement. Instead, the pressure relief device must be monitored after a pressure release the next time non-plant monitoring personnel are onsite, but in no event can the monitoring be delayed beyond 30 calendar days after a pressure release. Pressure relief devices that are routed to a process, fuel gas system, or control device are not required to be monitored following a release because the emissions from the release are controlled. [§60.5400b(d)(2)]

Figure 12-2. Requirements for Process Unit Equipment Affected Facilities Using Method 21 [§60.5401b]

a. Pressure relief devices at a non-fractionating plant where the non-fractionating plant is monitored only by non-plant personnel that are not onsite are not subject to the 5-day post-pressure release monitoring requirement. Instead, the pressure relief device must be monitored after a pressure release the next time non-plant monitoring personnel are onsite, but in no event can the monitoring be delayed beyond 30 calendar days after a pressure release. Pressure relief devices that are routed to a process, fuel gas system, or control device are not required to be monitored following a release because the emissions from the release are controlled. [§60.5401b(c)(2)]

The final rule requires that when a leak is detected it must be repaired. Valves must be repaired by replacing the leaking valve with a low-e packing or a low emission (low-E) valve, where technically feasible. The final rule also includes requirements that the leaking equipment must be tagged for identification and a first attempt at repair for all identified leaks must be commenced within 5 days after detection, with final repair completed within 15 days after detection (unless the delay-of-repair provisions are applicable). Delay of repair would be allowed where it is technically infeasible to complete repairs within 15 days without a process unit shutdown. [§60.5400b(h) and 60.5401b(i)]

12.3 How do I demonstrate initial and continuous compliance?

Initial and continuous compliance is demonstrated by conducting the monitoring required by §60.5400b or §60.5401b, depending on the monitoring methodology chosen. See Figure 12-3 (Initial Compliance Requirements for Process Unit Equipment Affected Facilities) for a summary overview of your initial compliance requirements and Figure 12-4 (Continuous Compliance Requirements for Process Unit Equipment Affected Facilities) for a summary overview of your continuous compliance requirements.

Figure 12-3. Initial Compliance Requirements for Process Unit Equipment Affected Facilities

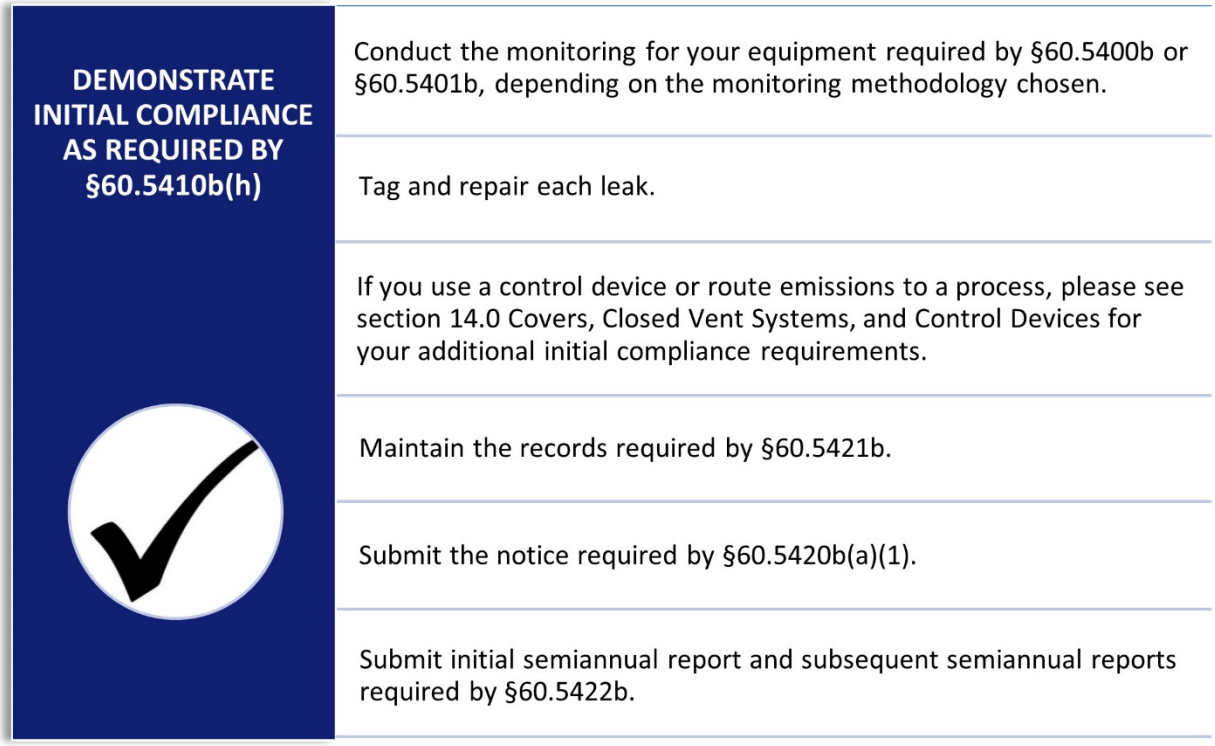
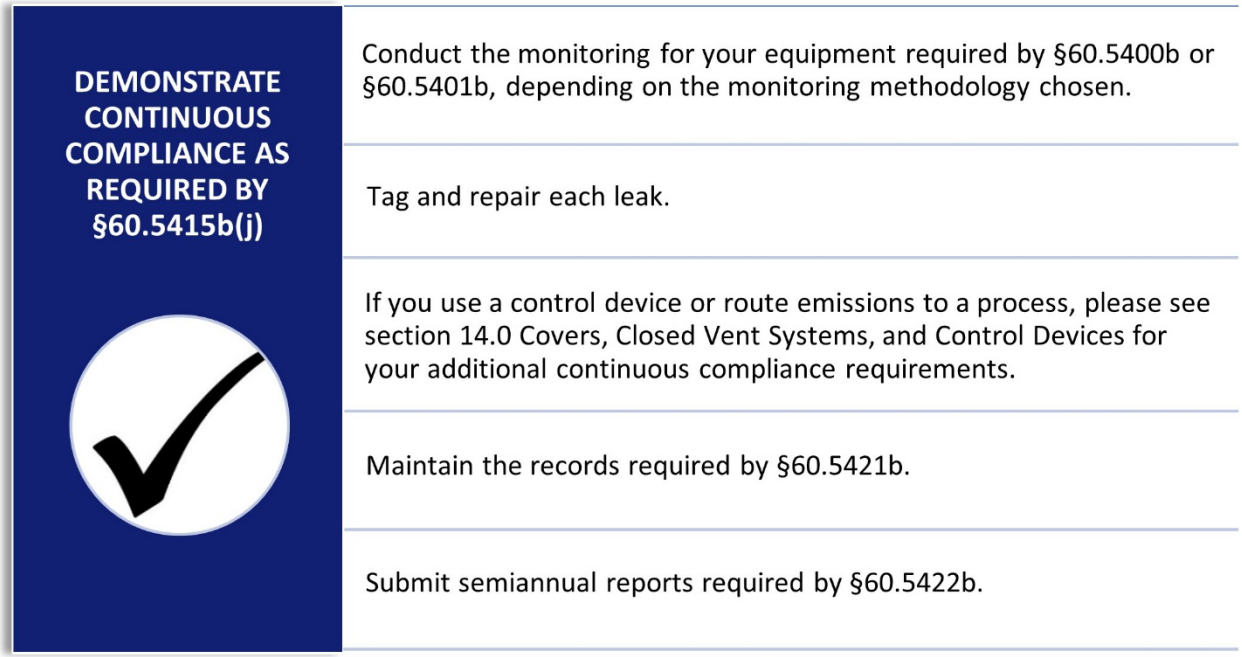


Figure 12-4. Continuous Compliance Requirements for Process Unit Equipment Affected Facilities

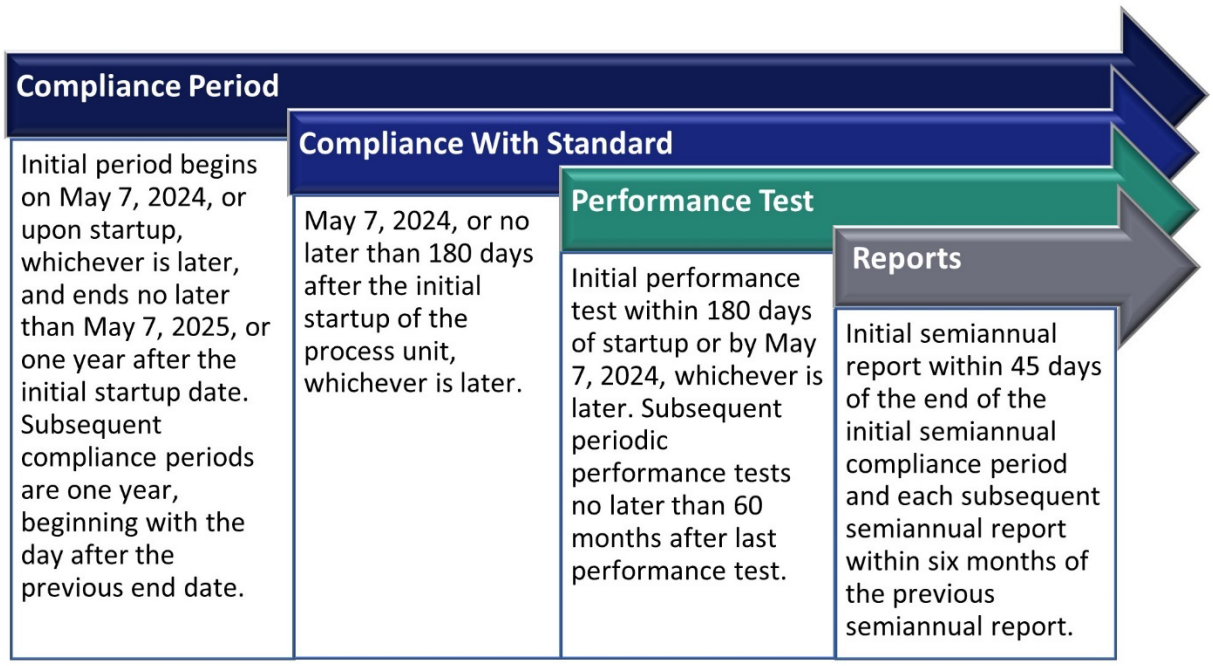


12.4 When must I comply?

You must be in compliance no later than May 7, 2024, or within 180 days of initial startup, whichever is later. [§60.5370b(a) introductory text and (a)(4)]. You must be in compliance with the 60.5400b requirements for each process unit equipment affected facility at a natural gas processing plant no later than May 7, 2024, or as soon as practicable, but no later than 180 day after the initial startup of each process unit. The initial compliance period begins on May 7, 2024, or upon initial startup, whichever is later, and ends no later than one year after the initial startup date or no later than May 7, 2025. [§60.5410b introductory text.] There are two semiannual reports due in the initial compliance period. You must submit your initial semiannual report within 45 days of the end of the initial semiannual compliance period and submit each subsequent semiannual report within six months of the previous semiannual report. [§60.5422b(a)] You must conduct an initial performance test within 180 days of initial startup or by May 7, 2024, whichever is later. [§60.5413b(b)(5)]

Figure 12-5 (Compliance Schedule for Process Unit Equipment Affected Facilities) provides a summary overview of the compliance schedule for equipment leaks at natural gas processing plants.

Figure 12-5. Compliance Schedule for Process Unit Equipment Affected Facilities



12.5 What testing or monitoring is required?

The rule requires use of OGI in accordance with Appendix K (or Method 21 as an alternative) for monitoring and identification of leaks and for resurvey after repair. Please see Appendix B for an overview of Appendix K requirements. If you comply by routing emissions from equipment through a CVS to a control device you also must meet the requirements in section 14.0 (Covers, Closed Vent Systems, and Control Devices) of this guide.

12.6 What, when and to whom must I report?

For each process unit equipment affected facility, you must submit the notifications required by §§60.7(a)(1), (3), and (4) and 60.15(d). In addition to the information outlined in section 1.4.3 (Requirements applicable to all affected facilities) of this guide, you must submit initial and semiannual reports as required by §60.5422b. If you use a CVS and control device to comply with the standards, you also must submit the applicable information in §60.5420b(b)(11) through (13).

12.7 What records must I keep?

For each process unit equipment affected facility you must maintain records as outlined in §60.5421b. In addition, if you use a CVS and control device to comply with the standards, you also must maintain the records in §60.5420b(c)(8) and (10) through (13), as applicable.

13.0 Sulfur Dioxide Standards for Sweetening Units at Onshore Natural Gas Processing Plants

13.1 How do I determine if my sweetening unit is an affected facility?

Each sweetening unit that processes natural gas or each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility. [§60.5365b(g)(1) and (2)]

Sweetening units that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas are required to comply only with recordkeeping and reporting requirements outlined in §60.5423b(e) and have no control or emission reduction requirements. [§60.5365b(g)(3)]

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 exempt from the rule requirements. [§60.5365b(g)(4)]

Definitions

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.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

13.2 How do I comply?

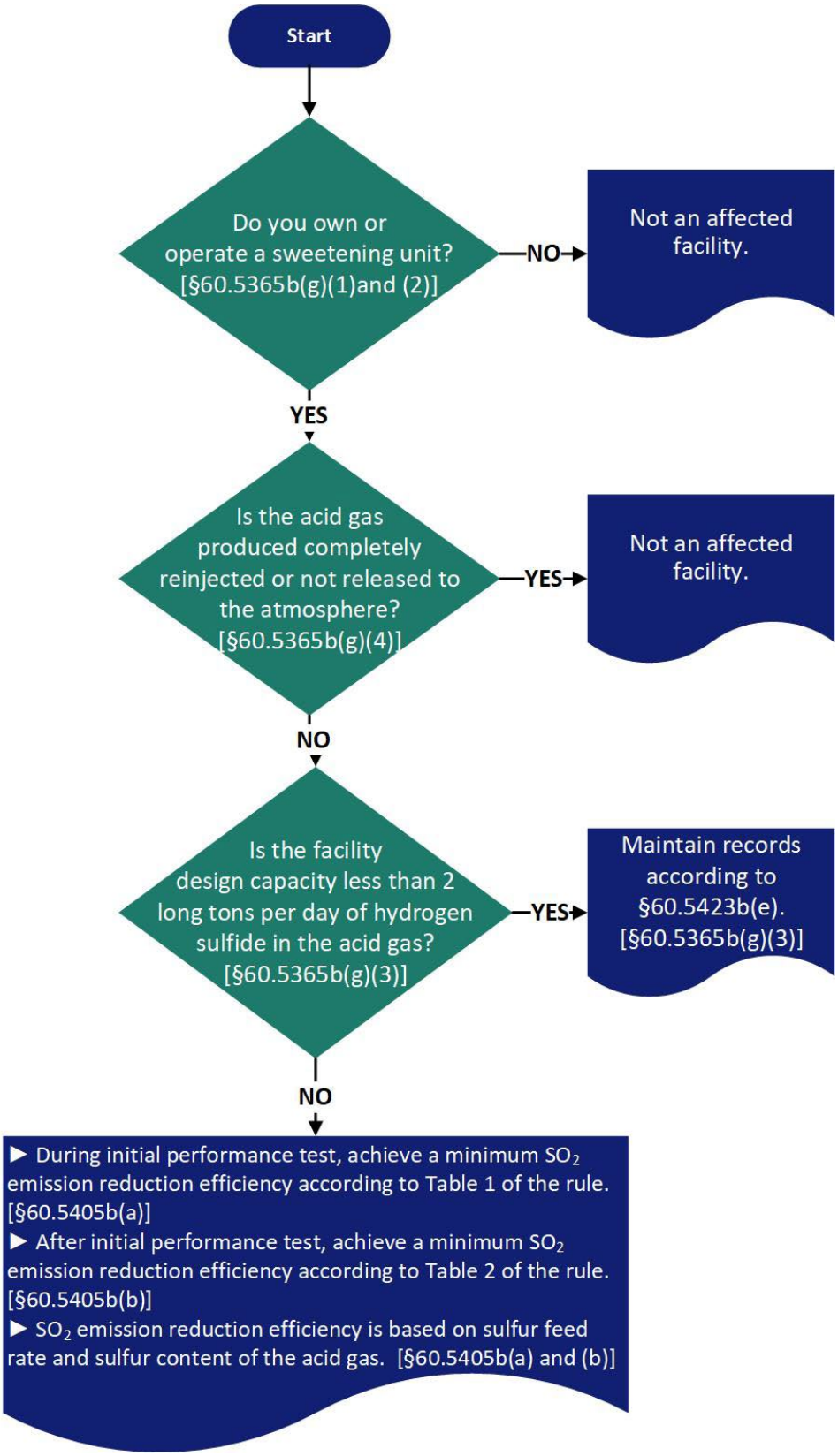
You must reduce SO_2 emissions and achieve an initial minimum SO_2 emission reduction efficiency as outlined in Table 3 (Table 3 to Subpart OOOOb of Part 60—Required Minimum Initial SO_2 Emission Reduction Efficiency (Z_i)) of the rule. [§60.5405(a)] You must conduct performance testing and determine initial compliance for your sweetening unit according to methods and procedures outlined in §60.5406b. [§60.5406b] See section 13.5 for a summary overview of the testing provisions for sweetening units.

After demonstrating initial compliance with Z_i, you must operate the sulfur recovery unit such that you achieve at a minimum SO_2 emission reduction efficiency as outlined in Table 4 (Table 4 to Subpart OOOOb of Part 60—Required Minimum SO_2 Emission Reduction Efficiency (Z_c)) of the rule. [§60.5405b(b)] The emission reduction efficiencies for Z_i and Z_c are based on

the sulfur feed rate and the sulfur content of the acid gas of the affected facility. [§60.5405b(a) and (b)] You must monitor the emissions and operation of the sweetening unit affected facilities and determine ongoing compliance according to the procedures outlined in 60.5407b. [§60.5407b(a)] You must demonstrate continuous compliance using the procedure outlined in §60.5415b(k). [§60.5415b(k)] See section 13.3 (How do I demonstrate initial and continuous compliance?) for a summary overview of the initial and continuous compliance requirements.

Figure 13-1 (Requirements for Sweetening Units) provides an overview of the applicable requirements for your sweetening unit affected facility.

Figure 13-1. Requirements for Sweetening Units



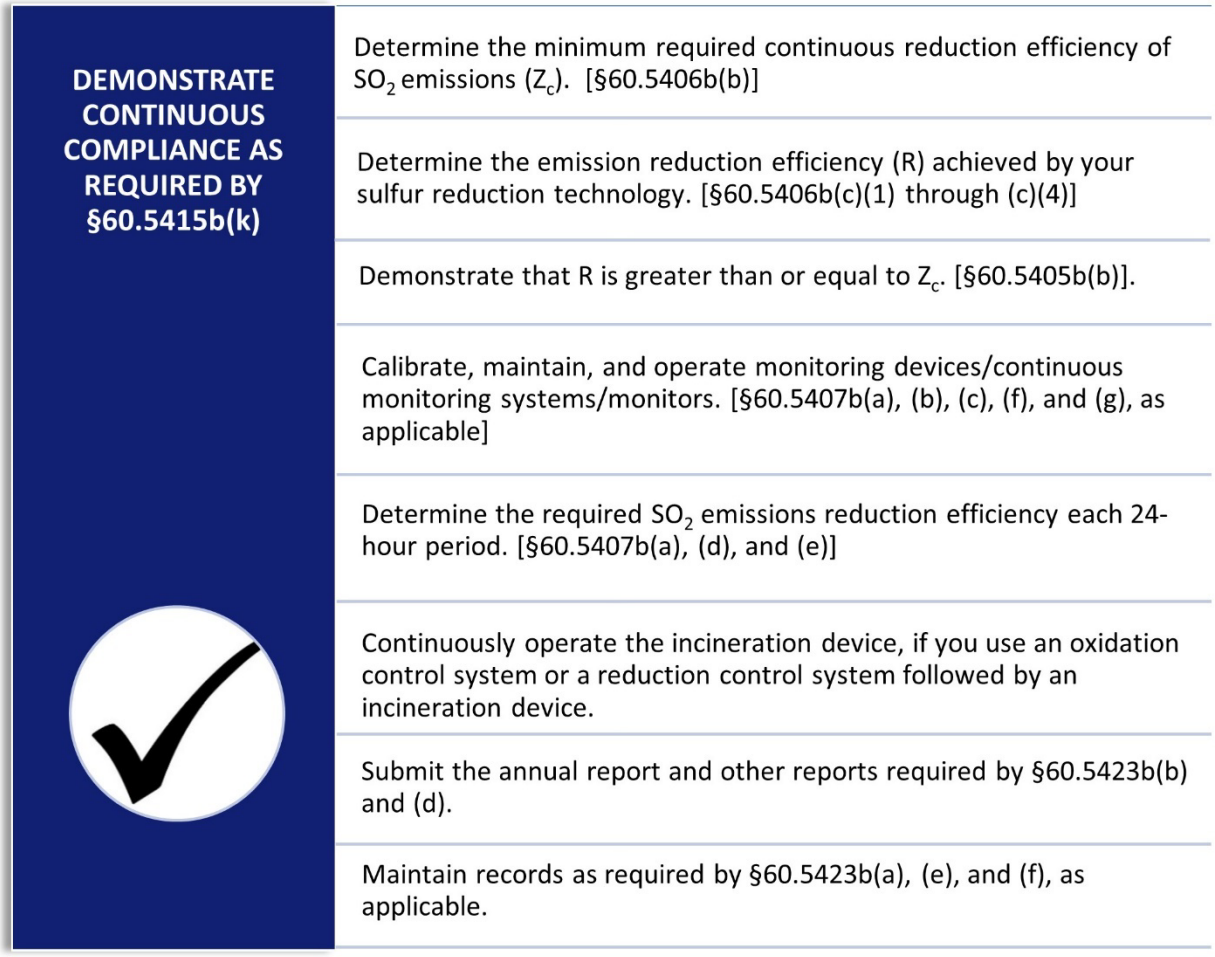
13.3 How do I demonstrate initial and continuous compliance?

Figure 13-2 (Initial Compliance Requirements for Sweetening Unit Affected Facilities) lists the requirements for demonstrating initial compliance and Figure 13-3 (Continuous Compliance Requirements for Sweetening Unit Affected Facilities) lists the requirements for demonstrating continuous compliance for your sweetening unit affected facility.

Figure 13-2. Initial Compliance Requirements for Sweetening Unit Affected Facilities

DEMONSTRATE INITIAL COMPLIANCE AS REQUIRED BY §60.5410b(i)	Conduct an initial performance test.
	Determine the minimum required initial reduction efficiency of SO_2 emissions (Z_i) ,and the emission reduction efficiency (R) achieved by your sulfur reduction technology.
	Demonstrate that R is greater than or equal to Z_i.
	Install, calibrate, maintain, and operate monitoring devices/continuous monitoring systems/monitors.
	Determine the required SO_2 emissions reduction efficiency each 24-hour period.
	Continuously operate incineration device if you use an oxidation control system, or a reduction control system followed by an incineration device.
	Submit notification required by §60.5420b(a)(1); performance test report; initial annual report; and annual excess emissions reports, if applicable.
	Maintain records required by §60.5423b(a), (e) and (f), as applicable.

Figure 13-3. Continuous Compliance Requirements for Sweetening Unit Affected Facilities

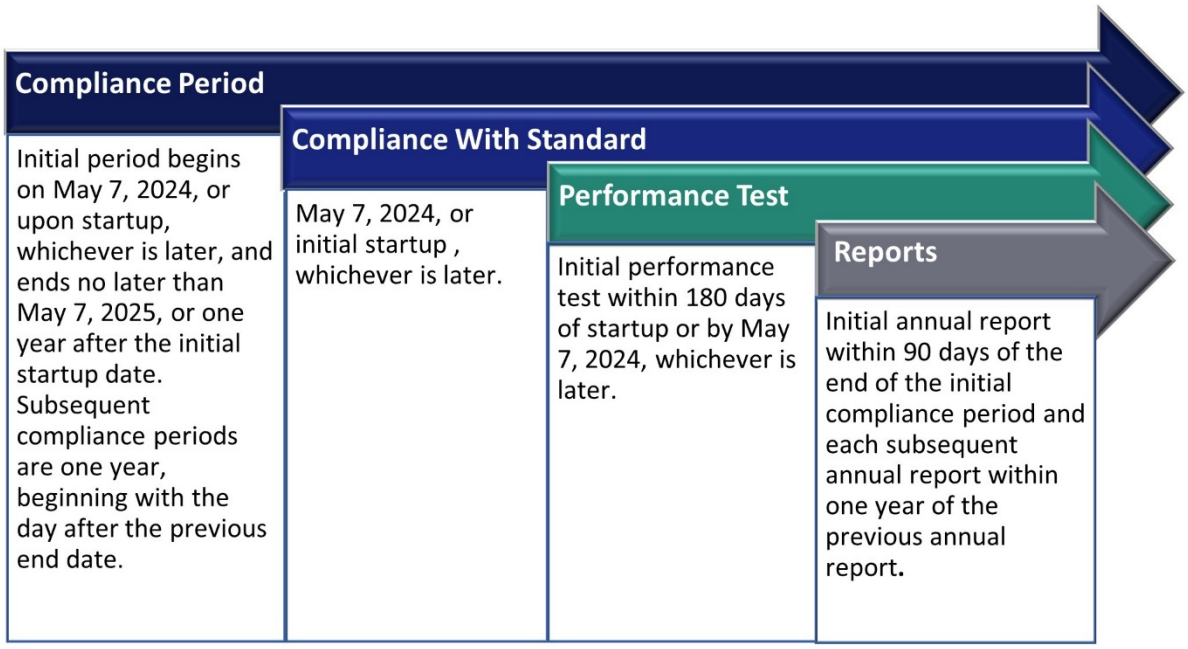


13.4 When must I comply?

You must be in compliance no later than May 7, 2024, or upon initial startup, whichever is later. [§60.5370b(a)] The initial compliance period begins on May 7, 2024, or upon initial startup, whichever is later, and ends no later than one year after the initial startup date or no later than May 7, 2025. [§60.5410b introductory text] You must submit your initial annual report within 90 days of the end of the initial compliance period, as described above and submit each subsequent annual report within one year of the previous annual report. [§60.5420b(b)] You must conduct an initial performance test within 180 days of initial startup or by May 7, 2024, whichever is later. [§60.5413b(b)(5)]

Figure 13-4 (Compliance Schedule for Sweetening Units) provides a summary overview of the compliance schedule for sweetening units.

Figure 13-4. Compliance Schedule for Sweetening Units



13.5 What testing or monitoring is required?

You must conduct performance testing according to the requirements outlined in §60.5406b, using the provisions of §60.8. You must monitor your sweetening unit according to the requirements outlined in §60.5407b, which include the installation, calibration, and operation of a CPMS. The CPMS must be calibrated at least annually and is subject to the emission monitoring requirements of §60.13. The monitoring system must provide at least one data point in each successive 15-minute interval. The CPMS must use at least two data points to calculate each 1-hour average and use a minimum of 18 1-hour averages to compute each 24-hour average.

Monitoring must be conducted for the following parameters:

- Accumulation of sulfur product over each 24-hour period
- H_2S concentration in the acid gas over each 24-hour period
- Average acid gas flow rate from the sweetening unit
- Sulfur feed rate for each 24-hour period
- Required SO_2 emission reduction efficiency for the 24-hour period (determined from the sulfur feed rate and H_2S concentration in the acid gas)
- Total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere
- Temperature of the gas leaving the combustion zone of the incinerator (if applicable)

[§60.5406b; §60.5407b]

13.6 What, when and to whom must I report?

For each sweetening unit affected facility, you must submit the notifications required in §60.7(a)(1), (3), and (4) and 60.15(d). You also must submit the information outlined in section 1.4.3 (Requirements applicable to all affected facilities) of this guide, the initial annual report, and annual excess emissions report as outlined in §60.5423b(b) and (d). [§60.5420b(a); §60.5423b]

13.7 What records must I keep?

For each sweetening unit affected facility you must maintain records as outlined in §60.5423b(a) and (e) and (f), as applicable. [§60.5423b]

14.0 Covers, Closed Vent Systems, and Control Devices

14.1 How do I determine if the requirements for covers, closed vent systems, and control devices apply to my affected facility?

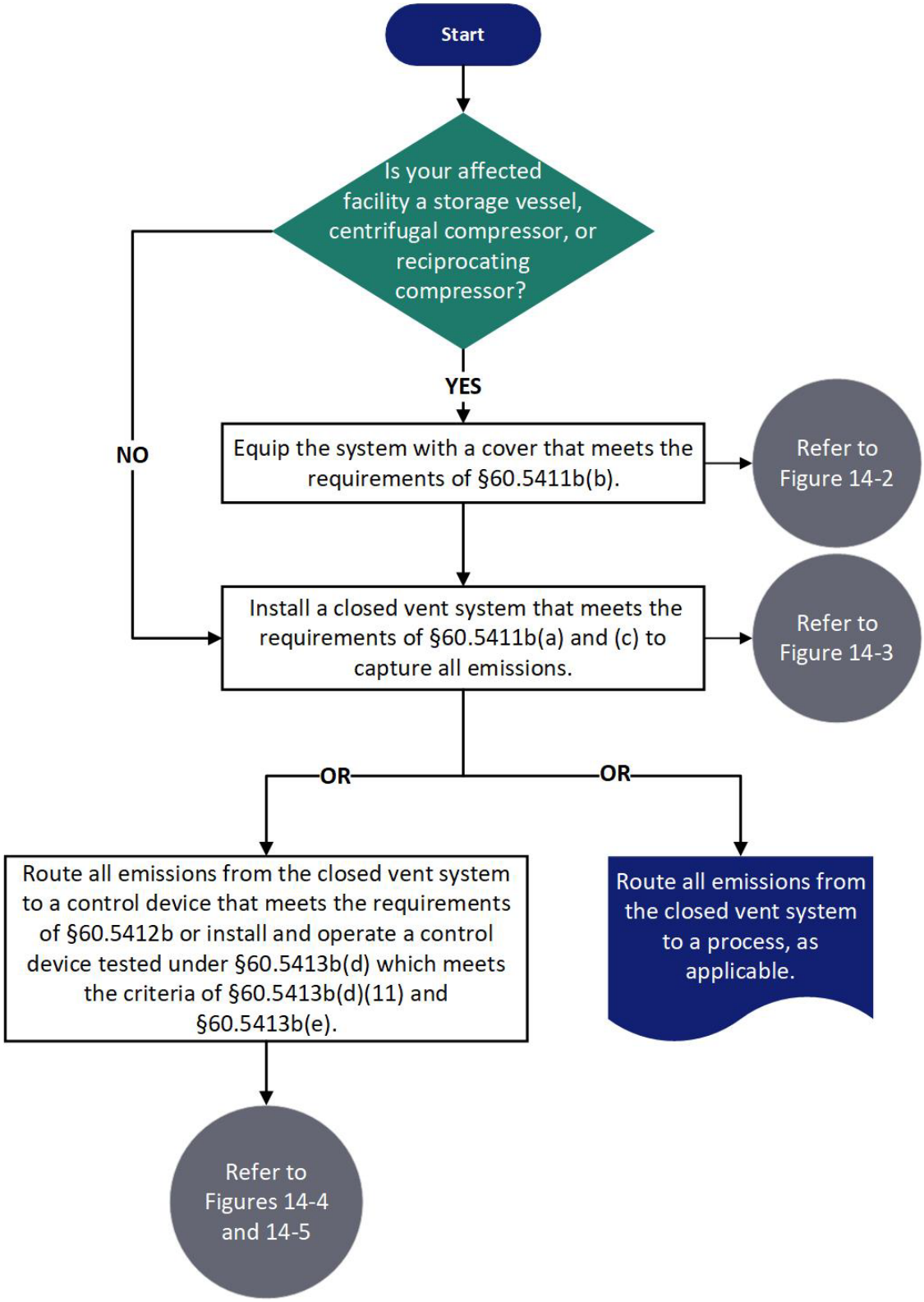
The requirements for covers apply to centrifugal compressors, reciprocating compressors, and storage vessel affected facilities. The requirements for CVSs apply to wells, centrifugal compressors, reciprocating compressors, process controllers, pumps, storage vessels, and process unit equipment affected facilities when controlling emissions by routing emissions to a control device. CVS requirements also apply to centrifugal compressors, reciprocating compressors, process controllers, pumps, storage vessels, and process unit equipment affected facilities when routing emission to a process. [§60.5411b] Control device requirements apply when emissions from your well, centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, or process unit equipment affected facility routes emissions to a control device.

Definition

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.

See Figure 14-1 (Overview of Performance Requirements for Covers, Closed Vent Systems, and Control Devices) for a summary overview of the performance requirements for covers, CVS, and control devices.

Figure 14-1. Overview of Performance Requirements for Covers, Closed Vent Systems, and Control Devices



14.2 How do I comply?

Each cover and all openings (e.g., access hatches, sampling ports, pressure relief devices and gauge wells) must 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 and must 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. There are exceptions during those times when it is necessary to use an opening as follows:

- 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);
- To inspect or sample the material in the unit;
- To inspect, maintain, repair, or replace equipment located inside the unit; or
- To vent liquids, gases, or fumes from the unit through a CVS to a control device or to a process. [§60.5411b(b)]

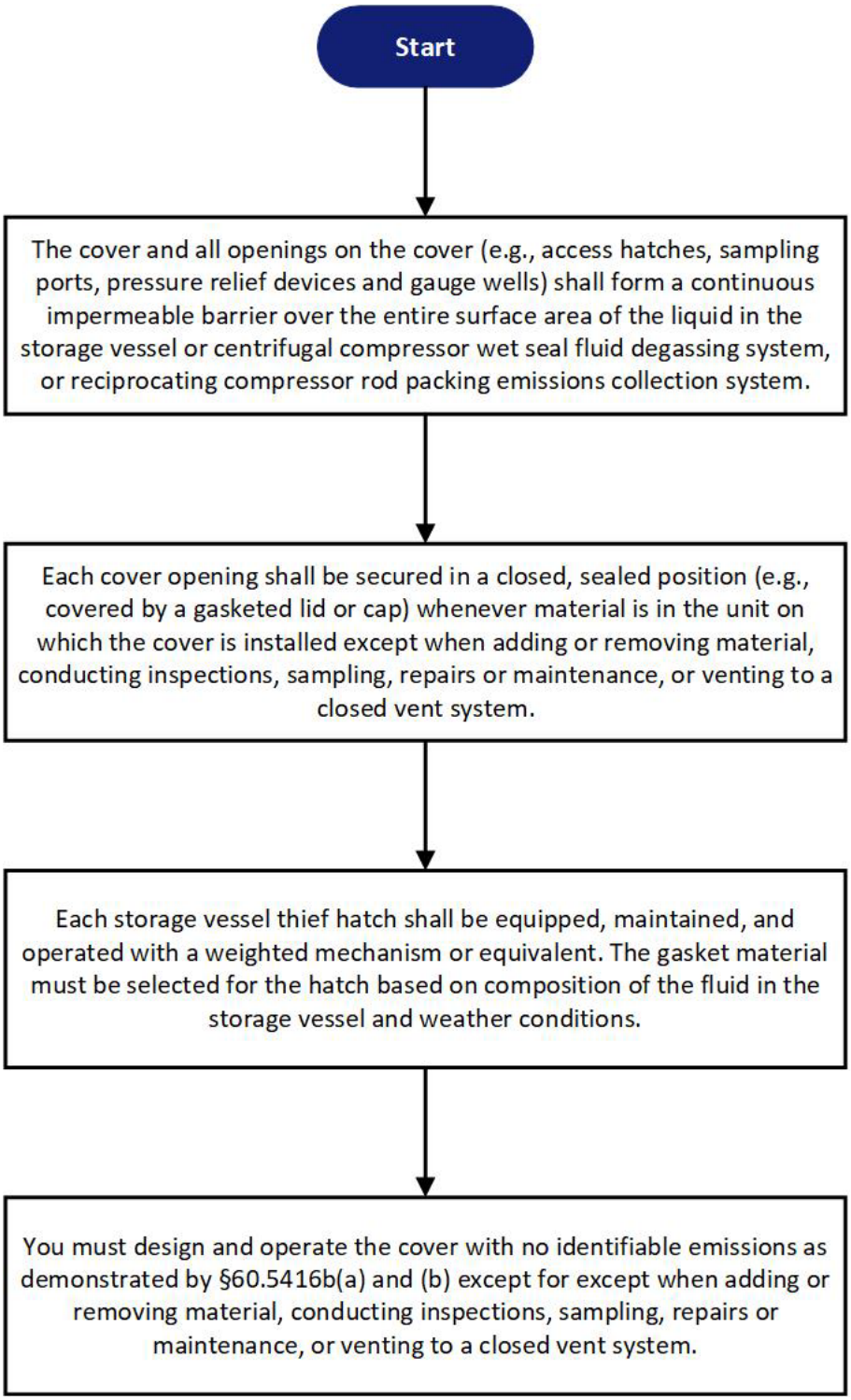
Each storage vessel thief hatch must be equipped, maintained, and operated with a weighted mechanism to make sure the lid remains properly seated and sealed under normal operating conditions, which includes times when working, standing/breathing, and flash emissions may occur. The gasket material for the hatch must be compatible with the fluid in the storage vessel and able to withstand weather conditions which may occur. [§60.5411b(b)(3)]

For all covers (including thief hatches), the cover must be designed and operated with no identifiable emissions, except for situations as described above. [§60.5411b(b)(4)] See Figure 14-2 (Overview of Design Requirements for Covers [§60.5411b(b)]) for a summary overview of the cover and thief hatch requirements.

Definition

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 of this part when inspections are conducted with Method 21.

Figure 14-2. Overview of Design Requirements for Covers [§60.5411b(b)]

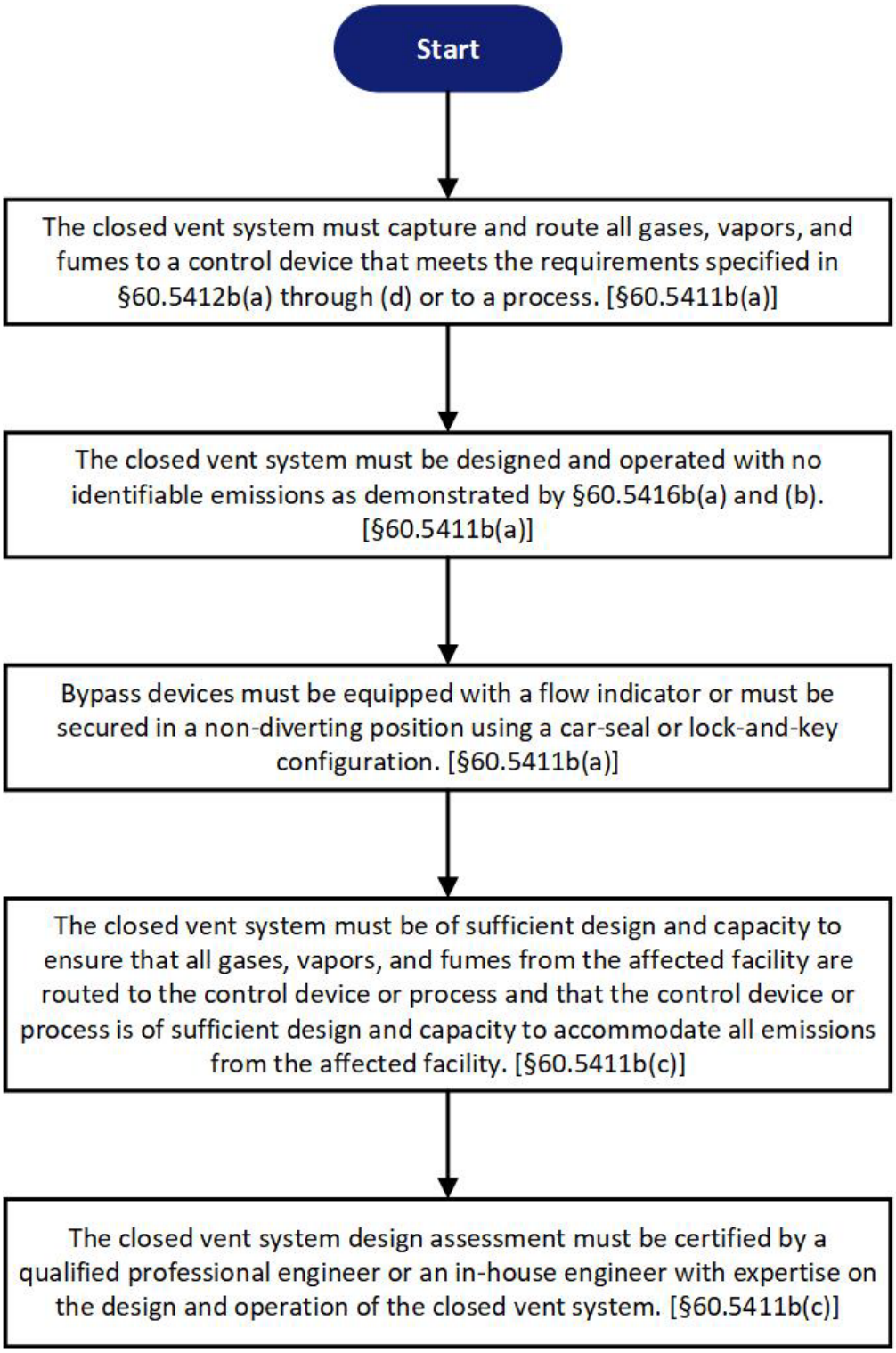


Each CVS must be designed to capture and route all gases, vapors, and fumes to a process or control device, as applicable. The CVS must be designed and operated with no identifiable emissions. If there is a bypass on the CVS, which could divert all or a portion of the gases, vapors, or fumes from entering the control device or being routed to a process, then the bypass has to have a flow indicator which will sound an alarm if the bypass is open. [§60.5411b(a)(4)]. If you do not install a flow indicator, then you must install a bypass device valve at the inlet to the bypass device and secure it in a non-diverting position with a car-seal or a lock-and-key type configuration. [§60.5411b(a)(4)]

Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices do not have to be monitored or sealed.

The design of each CVS shall include an assessment that the CVS is of sufficient design and capacity such that all gases, vapors, and fumes from the affected facility which uses the system are routed to the control device or process, as applicable. The assessment must be signed by a qualified professional or in-house engineer. See Figure 14-3 (Overview of Design Requirements for Closed Vent Systems) [§60.5411b(a) and (c)] for a summary overview of the design requirements for CVS. [§60.5411b(a) and (c)]

Figure 14-3. Overview of Design Requirements for Closed Vent Systems [§60.5411b(a) and (c)]



You also must conduct inspections for CVS, covers, and bypass devices and conduct performance tests and monitoring for your control devices. See section 14.3 for initial and continuous monitoring requirements. See section 14.5. for inspection requirements for covers, CVS, and bypass devices. See section 14.6 for testing requirements for control devices.

14.3 How do I demonstrate initial and continuous compliance?

To demonstrate initial compliance, please refer to the summary overview of requirements in Figure 14-4 (Initial Compliance Requirements for Control Devices).

Definition

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Figure 14-4. Initial Compliance Requirements for Control Devices

DEMONSTRATE INITIAL COMPLIANCE AS REQUIRED BY §60.5412b, §60.5415b, and §60.5417b	Conduct a performance test under §60.5413b(b) [a] or (d) or an alternative approved under §60.5412b(d). [§60.5412b(a) and (b)]
	Operate the control device at all times when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. [§60.5412b(b)]
	Operate below (or above) the site-specific maximum (or minimum) parameter value established for the control device [b] and meet the requirements of §60.5415(f). [§60.5412b(a) and (b)]
	For each ECD and flare, also operate with no visible emissions, except for periods not to exceed 1 minute in any 15-minute period. [§60.5412b(a)]
	Operate the CPMS at all times, except for periods of malfunctions/repairs and required quality assurance/control activities [§60.5412b(b); §60.5415b(f); §60.5417b(a)]
	For each ECD and flare, also operate with a pilot or combustion flame present at all times. [§60.5412b(a)]
	For each ECD and flare, conduct periodic OGI and AVO inspections. [§60.5415b(f)]
	For each carbon adsorption system, also replace all carbon in the carbon adsorption system with fresh carbon at the established interval and manage the carbon by burning, or regenerating or reactivating the carbon. [§60.5412b(c)]
	For each regenerative-type carbon adsorption system, unless equipped with a redundant flow sensor, also check the mechanical connections for leakage at least every month, and 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. [§60.5412b(c)]
	For each condenser, establish a site-specific condenser performance curve, calculate the daily average condenser outlet temperature, and determine the condenser efficiency. At the end of each day, calculate the 365-day rolling average TOC emissions reduction. [§60.5415b(a); §60.5417b(f)]
	Maintain records. [§60.5420b(c)(11) and (13)]
	Submit initial annual report. [§60.5420b(b)(11) through (13)]

a. Except for flares meeting §60.5412b(a)(3), control devices for which the performance test is waived under §60.8(b), boilers or process heaters with a design heat input capacity of 44 megawatts or greater; boiler and process heaters into which the vent stream is introduced with primary fuel or is used as the primary fuel; boilers or process heaters and hazardous waste incinerators operating under a final permit under 40 CFR part 270 and complying with 40 CFR part 266 subpart H; boilers and process heaters and hazardous waste incinerators meeting the requirements of 40 CFR part 63, subpart EEE; and vapor recovery devices which conduct a design analysis; which are exempt from the requirement to conduct an initial performance test.
b. Except for boilers and process heaters, which 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.

To demonstrate continuous compliance, please refer to the summary overview of requirements in Figure 14-5 (Continuous Compliance Requirements for Control Devices).

Figure 14-5. Continuous Compliance Requirements for Control Devices

DEMONSTRATE CONTINUOUS COMPLIANCE AS REQUIRED BY §§60.5413b(b) and 60.5415b(f)	Conduct a performance test every 60 months. [§60.5413b(b)(5)]
	Operate below (or above) the site-specific maximum (or minimum) parameter value established for the control device. [§60.5415b(f)(1)]
	Operate the CPMS at all times, except for periods of malfunctions/repairs and required quality assurance/control activities. [§60.5415b(f)(1)]
	For each ECD and flare, also operate the ECD or flare with a pilot or combustion flame present at all times. [§60.5415b(f)(1)]
	For each ECD and flare, also operate with no visible emissions, except for periods not to exceed 1 minute in any 15-minute period. [§60.5415b(f)(1)]
	For each ECD and flare, conduct periodic OGI and AVO inspections. [§60.5415b(f)(1)]
	For each ECD and flare, conduct periodic OGI and AVO inspections.
	For each regenerative-type carbon adsorption system, unless equipped with a redundant flow sensor, also check the mechanical connections for leakage at least every month, and 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. [§60.5415b(f)(1)]
	For each carbon adsorption system, also replace all carbon in the carbon adsorption system with fresh carbon at the established interval. [§60.5415b(f)(1)]
	For each condenser, establish a site-specific condenser performance curve, calculate the daily average condenser outlet temperature, and determine the condenser efficiency. At the end of each day, calculate the 365-day rolling average TOC emissions reduction. [§60.5415b(f)(1)]
	Submit annual report. [§§60.5415b(f)(3) and 60.5420b(b)(11) through (13)]
	Maintain records. [§§60.5415b(f)(2) and 60.5420b(c)(11) and (13)]

14.4 When must I comply?

The requirements for initial inspections and the installation of continuous parameter monitoring systems must be conducted by the compliance dates specified in §60.5370b for your affected facility which is using the cover, CVS, or control device. Performance testing for control devices must be conducted within 180 days of the compliance date for the affected source. [§60.5410b] On an ongoing basis, you must retest the control device at least every 60 months after the initial performance test.

14.5 What are my inspection requirements for covers, closed vent systems, and bypass devices?

Each CVS, cover, and bypass device must be inspected initially and periodically. Cover inspections are conducted to identify defects that could result in air emissions and to ensure the cover operates with no identifiable emissions (NIE). 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.

Definition

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 of this part when inspections are conducted with Method 21.

CVS inspections are conducted to ensure the CVS operates with NIE and are free of 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. See Table 14-1 (Overview of Inspection Requirements for Covers, Closed Vent Systems, and Bypass Devices) [§60.5416b] for a summary overview of the inspection requirements.

Table 14-1. Overview of Inspection Requirements for Covers, Closed Vent Systems, and Bypass Devices [§60.5416b]

For your…	You must
Cover NOT located at a gas plant. [a]	➢ Conduct an initial inspection following installation of the cover using OGI or Method 21 to ensure there are NIE. [§60.5416b(a)(3)(ii); §60.5416b(b)(1)(i)] ➢ Conduct periodic inspections with and at the same frequency as specified for the fugitive emission components affected facility located at the same type of site, using OGI or Method 21 to ensure there are NIE. [§60.5416b(a)(3)(iv); §60.5416b(b)(1)(i)] ➢ Conduct AVO inspections with and at the same frequency as specified for the fugitive emission components affected facility located at the same type of site. [§60.5416b(a)(3)(iii); §60.5416b(b)(1)(i)]
Cover located at a gas plant.	➢ Conduct an initial inspection following installation of the cover using OGI in accordance with Appendix K or Method 21 to ensure there are NIE. [§60.5416b(a)(3)(ii); §60.5416b(b)(1)(ii)] ➢ Conduct bimonthly inspections using OGI in accordance with Appendix K or quarterly inspections using Method 21 to ensure there are NIE. [§60.5416b(a)(3)(iv); §60.5416b(b)(1)(ii)] ➢ Conduct AVO inspections during the annual visual inspections of your CVS. [§60.5416b(a)(3)(iii); §60.5416b(b)(1)(ii)]

For your…	You must
Closed vent system NOT located at a gas plant.	➢ Conduct an initial inspection within the first 30 calendar days after startup of the affected facility routing emissions through the CVS, using OGI or Method 21, to ensure there are NIE. [§60.5416b(a)(1)(i) and (a)(2)(i); §60.5416b(b)(1)(i)] ➢ For CVS components that are not permanently or semi-permanently sealed, conduct periodic inspections with and at the same frequency as specified for the fugitive emission components affected facility located at the same type of site, using OGI or Method 21 to ensure there are NIE. [§60.5416b(a)(2)(ii); §60.5416b(b)(1)(i)] ➢ Conduct annual visual inspections for defects. [§60.5416b(a)(1)(ii) and (a)(2)(iii); §60.5416b(b)(1)(i)] ➢ Monitor a component or connection using OGI or Method 21 to demonstrate that it operates with no identifiable emissions following any time the component is repaired or replaced or the connection is unsealed. [§60.5416b(a)(1)(ii) and (a)(2)(iii); §60.5416b(b)(1)(i)] ➢ Conduct AVO inspections with and at the same frequency as specified for the fugitive emission components affected facility located at the same type of site. [§60.5416b(a)(1)(iii) and (a)(2)(iv); §60.5416b(b)(1)(i)]

For your…	You must
CVS located at a gas plant.	➢ Conduct an initial inspection within the first 30 calendar days after startup of the affected facility routing emissions through the CVS, using OGI in accordance with Appendix K or Method 21, to ensure there are no identifiable emissions (NIE). [§60.5416b(a)(1)(i) and (a)(2)(i); §60.5416b(b)(1)(ii)] ➢ For CVS components that are not permanently or semi-permanently sealed, conduct bimonthly inspections using OGI in accordance with Appendix K or quarterly inspections using Method 21 to ensure there are NIE. [§60.5416b(a)(2)(ii); §60.5416b(b)(1)(ii)] ➢ Conduct annual visual inspections for defects. [§60.5416b(a)(1)(ii) and (a)(2)(iii); §60.5416b(b)(1)(ii)] ➢ Monitor a component or connection using OGI in accordance with Appendix K or Method 21 to demonstrate that it operates with no identifiable emissions following any time the component is repaired or replaced or the connection is unsealed. [§60.5416b(a)(1)(ii) and (a)(2)(iii); §60.5416b(b)(1)(ii)] ➢ Conduct AVO inspections during the annual visual inspections of your CVS. [§60.5416b(a)(1)(iii) and (a)(2)(iv); §60.5416b(b)(1)(ii)]
Bypass Device	➢ Install a flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device. [§60.54165b(a)(4)(i)] ➢ Alternatively, secure the bypass device in a non-diverting position using a car-seal or lock-and-key configuration and visually inspect the seal or closure mechanism at least monthly. [§60.54165b(a)(4)(ii)]

Note: In the case where a 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 (fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

14.6 What testing or monitoring is required?

Performance testing must be conducted in accordance with §60.5413b.[5] For vapor recovery devices only, in lieu of a performance test, a vapor recovery device may demonstrate initial compliance by conducting a design analysis. [§§60.5412b(b) and 60.5413b(c)] Owners or operators of flares and enclosed combustion devices (ECDs) may submit a request for an alternative test method which demonstrates that the control device reduces methane and VOC emissions by 95.0 percent by weight or greater. [§60.8 and §60.5412b(d)] In lieu of conducting a performance test, an owner or operator can use a control device that has been tested by the manufacturer, if it is listed on the following website: **https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry**. [§60.5413b(d) and (e)] All control devices must be retested every five years.

You must demonstrate the performance of the control device on a continuous basis by setting limits on monitored parameters during the initial performance test.[6] [§§60.5417b(f) and 60.5417b(i)] See Appendix C of this guide for a summary overview of the parametric monitoring by control device type (i.e., enclosed combustor, vapor recovery device, or flare).

You must develop a site-specific monitoring plan and monitor your control device using a continuous parameter monitoring system (CPMS). The CPMS must collect data at least once every hour (except for CPMS used to detect the presence of a pilot or combustion flame, which must collect data at least once every 5 minutes). [§60.5417b(a) and (c)] You must conduct a performance evaluation[7] of each CPMS and conduct performance checks, system accuracy audits, and other audit procedures as outlined in your monitoring plan every 12 months. [§60.5417b(c)] The CPMS must continuously measure the operating parameters you determined during the performance test, or the CPMS must be an organic monitoring device

[5] Control devices for which the performance test is waived under §60.8(b), boilers or process heaters with a design heat input capacity of 44 megawatts or greater; boiler and process heaters into which the vent stream is introduced with primary fuel or is used as the primary fuel; boilers or process heaters and hazardous waste incinerators operating under a final permit under 40 CFR part 270 and complying with 40 CFR part 266 subpart H; boilers and process heaters and hazardous waste incinerators meeting the requirements of 40 CFR part 63, subpart EEE; and flares are exempt from the requirement to conduct an initial performance test.

[6] A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel, or which have a design heat capacity equal to or greater than 44 megawatts, are exempt from the monitoring requirements in §60.5417b(c) through (h). [§60.5417b(a) introductory text]and §60.5417b(b)] Unassisted flares with a NHV ≥ 200 Btu/scf; flares with pressure-assisted burner tips with a NHV ≥ 800 Btu/scf; and steam-assisted and air-assisted flares with a NHV_{cz} ≥ 270 BTU/scf do not have to comply with the requirements of §60.5417b(f) but must meet these operating limits. [§60.5417b(a) introductory text]

[7] Except heat sensing devices used for detection of the pilot or combustion flame are exempt from calibration, quality assurance, and quality control requirements.

meeting Performance Specification 8 or 9 that measures the concentration level of the organic compounds in the exhaust stream. [§60.5417(d)]

For enclosed combustors and flares, you must use a calorimeter, gas chromatograph, mass spectrometer, or continuous sampling system to determine the net heating value (NHV) of the vent stream. As an alternative to continuous monitoring of NHV, you may perform initial (twice daily for 14-consecutive days) sampling and periodic (every five years) resampling (three samples) to determine the NHV of the vent stream. As an alternative to the continuous monitoring of the inlet gas flow rate, you may install a backpressure regulator valve that is calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. Steam-assisted and air-assisted enclosed combustors and flares also must determine the combustion zone NHV (NHV_{cz}) and the NHV dilution parameter (NHV_{dil}) and monitor the vent gas and assist gas in accordance with the provisions in §63.670 of MACT CC (Refinery MACT). [§60.5417(d)]

For all CPMS, 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. Failure to collect required data is a deviation of the monitoring requirements. You must calculate the daily average of the monitored parameter and compare it to the limit determined during the performance test. [§60.5417b(e)]

Deviations to parametric monitoring occur when:

- The average value of a monitored parameter is less than the minimum or greater than the maximum operating parameter limit.
- The heat sensing device indicates that there is no pilot or combustion flame present for any time period.
- The backpressure regulator valve set point is not set correctly or the valve does not fully close (as applicable for backpressure regulator valves).
- For condensers, the 365-day average is less than 95 percent.
- Monitoring data are not available for at least 75 percent of the operating day.
- Bypass monitoring indicates the vent stream is diverted from the control device (as applicable for CVS equipped with one or more bypass valves).
- Control devices tested by the manufacturer are not maintained in a leak free condition and operated in accordance with the manufacturer's written instructions.

- The NHV_{cz} or NHV_{dil} is below the applicable limit (as applicable for steam and air-assisted control devices).
  [§60.5417b(g)]

14.7 What, when and to whom must I report?

For your covers, CVS, and control devices you must submit the information outlined in section 1.4.3 (Requirements applicable to all affected facilities) of this guide and you must include the information applicable information in §60.5420b(b)(11) through (13).

14.8 What records must I keep?

You must maintain the records in in §60.5420b(c)(8) through (13), as applicable.

15.0 Overview of Who Implements and Enforces the Rule and How to Report Violations

15.1 Who implements and enforces the rule?

The EPA is responsible for implementation of this rule and its enforcement. In fact, there are certain aspects of this rule that the EPA may not delegate. The following authorities rest solely with the EPA:

- Approvals of alternative or equivalent test methods (§60.8(b)(2) and (b)(3)).
- Equivalency determinations (§60.5398b and §60.5402b).

Definition

Delegate means that the EPA grants authority to another entity (e.g., state, local, or tribe) to carry out the requirements of the rule. Under such delegations, the EPA still retains their own authorities.

However, the EPA may delegate implementation and enforcement authority to a state, local or tribal authority upon request. Any provisions of NSPS OOOOb, not noted above, may be delegated.

Finally, it should be noted that this compliance guide explains your federal compliance obligations with respect to this NSPS federal rule. There may be other state or local requirements that apply to you which are different from, or more stringent than, the federal requirements described in this guide.

15.2 What must I do in the event of a potential violation?

Assuring compliance with our nation's environmental laws is one of the EPA's primary commitments. In carrying out this responsibility, we use many different approaches. One approach is to seek help from you by asking you to provide the EPA with information about potentially harmful environmental activities in your communities and workplaces. Reports from the public have led to state and federal enforcement cases and ultimately served environmental protection well. We invite you to help us protect our nation's environment by identifying and

reporting environmental violations. The EPA's *Report an Environmental Violation* website[8] provides a way for you to report suspected environmental violations. Violations may take many different forms. Some are done intentionally and may be criminal violations. For more information on environmental crimes, please see Violation Types and Examples on our website.[9] For voluntary self-disclosures for civil violations, please see EPA's Audit Policy.[10]

As noted above in section 15.1 (Who implements and enforces the rule?), certain enforcement authorities under this rule may have been delegated to State, local or tribal authorities. If this is the case in your State, you also should contact these State, local or tribal authorities in the event of a violation.

[8] **https://www.epa.gov/enforcement/report-environmental-violation-general-information**
[9] **https://www.epa.gov/enforcement/criminal-investigations-violation-types-and-examples**
[10] **https://www.epa.gov/compliance/epas-audit-policy**

16.0 More Information for Further Assistance

16.1 Who can I contact if I have questions or need further assistance?

For questions about this final rule for the oil and natural gas sector please email: O&GMethaneRule@epa.gov or contact Ms. Amy Hambrick at the Office of Air Quality Planning and Standards, Sector Policies and Programs Division (E143-05), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541-0964; email address: hambrick.amy@epa.gov.

For additional assistance at the EPA regional level, the following region-specific EPA personnel may also be contacted at the Regional Offices:

- Region 1 – Kate Crowley at crowley.kate@epa.gov;
- Region 2 – Harish Patel at patel.harish@epa.gov;
- Region 3 – Bruce Augustine at Augustine.bruce@epa.gov or Dean Deluca at deluca.dean@epa.gov;
- Region 4 – Kevin Taylor at taylor.kevin@epa.gov;
- Region 5 – Natalie Topinka at Topinka.natalie@epa.gov;
- Region 6 – Jamie Salabogi at salabogi.jamie@epa.gov or Bailey Brown at brown.bailey@epa.gov;
- Region 7 – Sean Bergin at bergin.sean@epa.gov or Kyle Youngs at youngs.kyle@epa.gov;
- Region 8 – Alexis North at north.alexis@epa.gov;
- Region 9 – Ethan Hessl at hessl.ethan@epa.gov;
- Region 10 – Brendan Whyte at whyte.brendan@epa.gov.

To determine which region your state is located in, please refer to the Map of EPA Regions provided **https://www.epa.gov/aboutepa**.

16.2 Where can I find the rulemaking and related documents?

- The final "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review"

rulemaking (89 FR 16820, March 8, 2024) is available as a Federal Register document at [**https://www.federalregister.gov/documents/2024/03/08/2024-00366/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for**].

- All rulemaking documents and information, including background data and analyses, regarding this rulemaking can be found in Docket ID EPA-HQ-OAR-2021-0317 on Regulations.gov at **https://www.regulations.gov/docket?D=EPA-HQ-OAR-2021-0317**.
  Supporting technical information for the final rule can be found in the following Technical Support Documents (TSDs):
  - **Proposal TSD**: Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review - Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG). October 2021.
  - **Supplemental Proposal TSD:** Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Supplemental Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG). October 2022.
  - **Final TSD:** Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review - Background Technical Support Document (TSD) for the Final New Source Performance Standards (NSPS) and Emissions Guidelines (EG). November 2023.

  These TSDs can be found in the docket, EPA Docket ID: EPA-HQ-OAR-2021-0317-0166, 1578, and 3988, respectively.

16.3 What is the compliance assurance process?

To maximize compliance, the EPA implements a balanced program of compliance assistance, compliance incentives, and traditional law enforcement. The EPA knows that small businesses which must comply with complicated new statutes or rules often want to do the right thing, but may lack the requisite knowledge, resources, or skills. Compliance assistance information and technical advice helps small businesses to understand and meet their environmental obligations.

An effective environmental protection system requires a strong and vigorous enforcement program. OECA has striven to protect human health and the environment. Using an appropriate combination of enforcement and compliance assistance, we and our partners prevent and reduce pollution, thereby protecting human health and the environment.

Compliance monitoring is one of the key components EPA uses to ensure that the regulated community obeys environmental laws and regulations. It encompasses all regulatory agency activities

performed to determine whether a facility (or group of facilities, such as plants related geographically, by sector, or corporate structure) is in compliance with applicable law. Compliance monitoring includes:

- Onsite compliance monitoring: compliance inspections, evaluations, and investigations (including review of permits, data, and other documentation)
- Off-site compliance monitoring: data collection, review, reporting, program coordination, oversight, and support

Inspections are an integral part of EPA's compliance monitoring programs. They are an important tool for officially assessing compliance with environmental regulations and requirements. EPA and its regulatory partners conduct compliance inspections under the majority of statutory and regulatory program authorities.

Inspections are visits to a facility or site for the purpose of gathering information to determine whether it is in compliance. Inspections generally include pre-inspection activities such as obtaining general site information before entering the facility or site. Other activities that may be conducted during the onsite visit include:

- Interviewing facility or site representatives,
- Reviewing records and reports,
- Taking photographs,
- Collecting samples, and
- Observing facility or site operations.

The intensity and scope of an inspection can range from a quick walk-through inspection that takes less than half a day, to an inspection with extensive physical sample collection that can take weeks to complete.

The EPA provides compliance incentives and auditing to encourage facilities to find and disclose violations to the Agency. The EPA has developed the Small Business Compliance Policy which promotes environmental compliance among small businesses (those with 100 or fewer employees) by providing incentives to discover and correct environmental problems. EPA will eliminate or significantly reduce penalties for small businesses that voluntarily discover violations of environmental law and promptly disclose and correct them. The Policy accomplishes this in two ways: by setting forth guidelines for the Agency to apply in reducing or waiving penalties for small businesses that come forward to disclose and make good faith efforts to correct violations, and by deferring to State, local and Tribal governments that offer these incentives. A copy of this policy can be found at **https://www.gpo.gov/fdsys/pkg/FR-2000-04-11/pdf/00-8955.pdf**. For businesses with more than 100 employees, we have the "EPA Audit Policy" (available at **https://www.gpo.gov/fdsys/pkg/FR-2000-04-11/pdf/00-8954.pdf**) formally entitled, "Incentives for Self-Policing: Discovery, Disclosure, Correction and Prevention of Violations."

Definitions

Promptly disclosed means, under both the Audit Policy and Small Business Compliance Policy, potential violations must be disclosed online within 21 calendar days of the regulated entity's discovery that such potential violations may have occurred. If the 21st day after discovery falls on a weekend or federal holiday, the eDisclosure system will treat the disclosure as prompt if it is submitted on the next business day.

Discovery is when any officer, director, employee, or agent of the facility has an objectively reasonable basis for believing that a violation has or may have occurred.

Under the EPA Audit Policy, the EPA will eliminate or reduce the gravity component of civil penalties against small businesses based on the following criteria:

- Discovery is voluntary (i.e., the small business discovers a violation on its own before an EPA or State inspection). These violations can be discovered after receiving compliance assistance, conducting an environmental audit or participating in mentoring programs. Other activities that may be useful in discovering violations include establishing CMS, using compliance checklists, reading materials on complying with environmental requirements, using compliance assistance center web sites, and attending training classes. The violation must be identified voluntarily, and not through a monitoring or sampling requirement prescribed by statute, regulation, permit, judicial or administrative order, or consent agreement.
- Violations must be disclosed fully and in writing to the EPA or the State within 21 calendar days after the small business has discovered that the violation has occurred or may have occurred. Prompt disclosure is evidence of the small business's good faith in wanting to achieve or return to compliance as soon as possible. Good faith also requires that a small business cooperate with the EPA and in a timely manner provide such information requested by the EPA to determine applicability of this Policy.
- The business corrects the violation within the shortest practicable period of time. Correcting the violation includes remediating any environmental harm associated with the violation, as well as putting into place procedures to prevent the violation from happening again.
    - For any violation that cannot be corrected within 90 calendar days of its discovery, the small business must submit a written schedule, or the agency may, at its sole discretion, elect to issue a compliance order with a schedule, as appropriate. The small business must correct any violations within 180 calendar days after the date that they were discovered.
    - If the small business intends to correct the violation by putting into place pollution prevention measures, the business may take an additional period of up to 180 calendar days, i.e., up to a period of 360 calendar days from the date the violation is discovered.

As of December 9, 2015, the EPA modernized the implementation of its violation self-disclosure policies by creating a centralized web-based "electronic self-disclosure (eDisclosure)" portal to receive and automatically process self-disclosed civil violations of environmental law. Under the automated system, large and small businesses will quickly be able to get some of their more routine types of disclosures resolved. More information may be found at the EPA eDisclosure web page. In general, in order to submit an eDisclosure you must first register with the EPA's CDX system. Then you submit a voluntary prompt disclosure and within 60 days submit a Compliance Certification in the eDisclosure system.

Please visit our Audit Policy page on the web[11] for more information and Audit Policy Contacts. For civil violations please see the EPA Regional contacts in section 16.1 of this guide. To determine which region your state is located in, please refer to the Map of EPA Regions provided on the following the EPA webpage - **https://www.epa.gov/aboutepa**.

16.4 If the Agency discovers a violation, what might be its response?

As discussed previously, the EPA uses a variety of methods to determine whether businesses are complying, including inspecting facilities, reviewing records and reports, and responding to citizen complaints. If we learn a person is violating the law, the EPA (or a State, if the program is delegated) and citizens may file an enforcement action requiring compliance and seeking mitigation for any harm caused by the violation and also penalties. The proposed penalty in a given case will depend on many factors, including the number, length, and severity of the violations, the economic benefit obtained by the violator, and its ability to pay.

Under the Clean Air Act and EPA's penalty policies, the penalty will depend on many factors, including policies to ensure penalties are calculated fairly. These policies are available to the public and may be found at **https://www.epa.gov/enforcement/policy-guidance-publications#models**.

In addition, any company charged with a violation has the right to contest the EPA's allegations and proposed penalty before an impartial judge or jury.

In summary, the EPA recognizes that we can achieve the greatest possible protection by encouraging small businesses to work with us to discover, disclose, and correct violations. That is why we have issued self-disclosure, small business, and small community policies to eliminate or reduce penalties for small and large entities that cooperate with the EPA to address compliance problems.

16.5 What is the legal status of this guide?

- A judge can look at a compliance guide in determining what penalty is appropriate and reasonable, although the content of the guide cannot otherwise be reviewed by the court.
- In this Compliance Guide, we have tried to make clear what you must do to comply with the

[11] **https://www.epa.gov/compliance/epas-audit-policy**

applicable law and regulation. This is the minimum required by SBREFA. We hope you find this presentation of regulatory requirements useful in reaching and maintaining compliance.

16.6 How do I minimize harm if I think I am out of compliance?

If you believe that you are out of compliance or have some doubt as to the existence of a violation, EPA recommends that the business make a prompt disclosure and allow the regulatory authorities to make a definitive determination. This will ensure that the small business meets the disclosure period requirement under the Audit Policy. In the meantime, you can do one or more of the following options to stop or minimize emissions from the source:

- Stop or bypass the equipment or process where you believe the noncompliance is occurring to eliminate the noncompliant emissions,
- Reduce the production rate of the process or throughput of the equipment to minimize the noncompliant emissions from that source.

16.7 What is pollution prevention and how can it affect my operations?

Pollution prevention is any practice that reduces, eliminates, or prevents pollution at its source. The prevention of pollution means less hazards posed to public health and the environment. Pollution prevention approaches can be applied to all pollution-generating activities, including many found in the oil and natural gas sector. These approaches include increasing efficiency in energy use and use of environmentally benign fuel sources, modifying a production process to produce less waste, using non-toxic or less toxic chemicals as cleaners, degreasers and other maintenance chemicals and implementing water and energy conservation practices.

Since 1993, EPA has partnered with oil and natural gas operators to encourage the identification and implementation of technologies and practices to reduce methane emissions from the oil and gas sector. Through the Natural Gas STAR Program, EPA hosts workshops and webinars, shares technical resources, and directly partners with oil and gas operators.[12] A resource of pollution prevention practices can be found at Natural Gas STAR (**https://www.epa.gov/natural-gas-star-program/methane-mitigation-technologies-platform**). This website includes key methane emission sources in the oil and gas industry as well as technologies and practices that can be used to reduce methane emissions from these sources, many of which, are pollution prevention practices. To the extent that the Natural Gas STAR Program identifies other pollution prevention opportunities, including those which may make good business sense or could exempt a small entity from certain requirements, the Natural Gas STAR Program, with support from the Office of Pollution Prevention and Toxics, has the option to include these pollution prevention opportunities on their site.

[12] **https://www.epa.gov/natural-gas-star-program#:~:text=Why%20Focus%20on%20Methane%3F%201%20Methane%20is%20a,natural%20gas%2C%20an%20important%20energy%20source.%20More%20items**

16.8 How useful was this guide?

The EPA is continually striving to improve outreach to regulated entities and the public. Please let us know how useful this guide was to you, including its readability and suggestions you may have for improvements. You may direct all feedback to Ms. Amy Hambrick at the Office of Air Quality Planning and Standards, Sector Policies and Programs Division (E143-05), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number (919) 541-0964; email address: **hambrick.amy@epa.gov**.

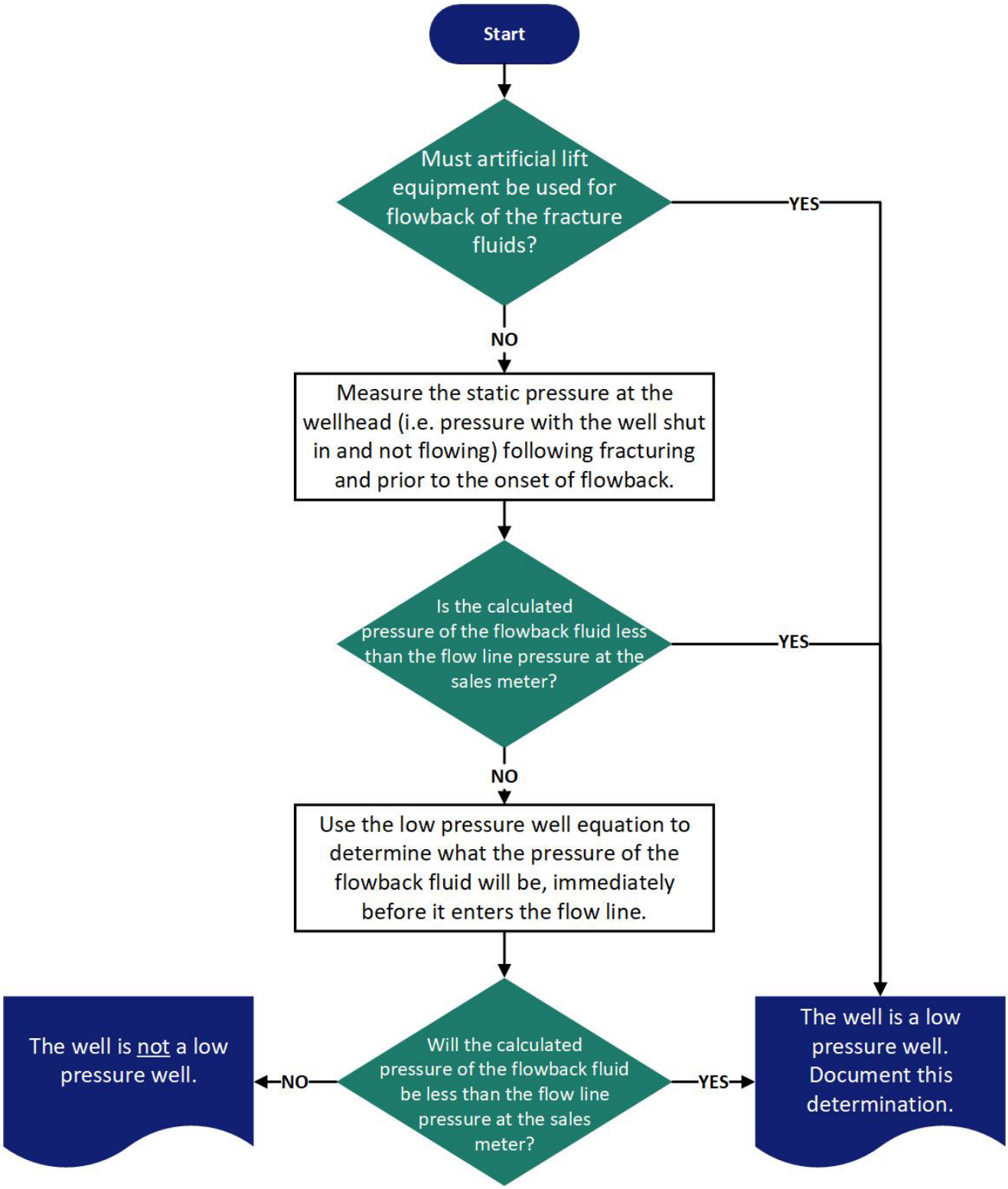
Appendix A: Conducting A Low Pressure Well Determination

A.1 How do I determine if my well is a low pressure well?

Low pressure wells have specific requirements under the rule. Therefore, you will need to determine if your well meets the definition of low pressure well to determine the requirements for the well. As with all determinations conducted for compliance under the rule, you must maintain records of all input data, calculations or other pertinent information supporting the outcome of your low pressure well determination. Figure A-1 provides a schematic of the process for determining if your well is a low pressure well.

Instead of using the low pressure well equation, under the final rule, operators who suspect that a well may be a low pressure well have the option, for screening purposes, of performing a wellhead static pressure (i.e., pressure with the well shut in and not flowing) check following fracturing and prior to the onset of flowback.

Figure A-1. How Do I Determine if My Well is a Low Pressure Well?



The definition of a low pressure well as provided in §60.5430b is:

Low pressure well means a well that satisfies at least one of the following conditions:

- The static pressure at the wellhead following fracturing but prior to the onset of flowback is less than the flow line pressure at the sales meter;
- The pressure of flowback fluid immediately before it enters the flow line, as determined under §60.5432b, is less than the flow line pressure at the sales meter; or
- Flowback of the fracture fluids will not occur without the use of artificial lift equipment.

You must determine, in advance of the start of flowback, whether your well is a low pressure well to apply the appropriate requirements to the well completion operation.

Under the final rule, your well qualifies as a low pressure well if it meets any one of the above conditions. Each of these conditions is explained further below.

A.2 Static Pressure at the Wellhead

If you suspect that your well may be a low pressure well, you have the option of checking the wellhead static pressure (i.e., pressure with the well shut in and not flowing) following fracturing and prior to the onset of flowback. If the static pressure at the wellhead is less than the pressure at the sales meter of the flow line to which you would direct the recovered gas, the well qualifies as a low pressure well.

To use this option, measure the static pressure at the wellhead with the well shut in, after fracturing but before the onset of flowback. Measure the static pressure at the wellhead using standard industry methods.

When you have measured the static pressure at the wellhead, compare it to the flow line pressure at the sales meter. If the static pressure measured at the wellhead is less than the flow line pressure, the well qualifies as a low pressure well. You will need to keep a record to document this determination and submit that documentation in the initial annual report for the well. [§60.5420b(b)(2)(iii) and §60.5420b(c)(1)(vii)]

If the static pressure measured at the wellhead is not less than the flow line pressure at the sales meter, you may still be able to qualify the well as a low pressure well using the low pressure well equation included in the rule. This is possible because the dynamic pressure that

you calculate for the well using the low pressure well equation should be lower than the static pressure you measured at the wellhead. The next section explains how to use the low pressure well equation.

A.3 Low Pressure Well Equation

You may also use the low pressure well equation to calculate the pressure of flowback fluid immediately before it enters the flow line, so that this value can be compared to the flow line pressure at the sales meter. If the calculated pressure is lower than the flow line pressure, your well qualifies as a low pressure well.

This equation was developed using an energy balance that takes into account the main components of pressure drop for oil and gas wells – hydrostatic and frictional. It uses parameters for which values you can estimate, based on knowledge of the formation and reservoir and standard industry practice before starting a well completion operation.

If you choose to calculate the pressure of flowback fluid immediately before it enters the flow line, you must use this calculation and the respective required inputs. No other calculation may be used to meet the rule requirements.

These parameters include the following:

- Pressure of the reservoir containing oil, gas, and water at the well site, expressed in pounds per square inch absolute (psia), PR;
- Bottom hole pressure, expressed in psia, PBH (also see Step 1);
- Bottom hole temperature, expressed in °F, TBH (also see Step 2);
- True vertical depth of the well, expressed in feet (ft.), L;
- Oil production rate, expressed in STBOD, Q_o;
- Water production rate, expressed in STBOD, Q_w;
- Gas production rate, expressed in standard cubic feet per day (scf/day), Q_g; and
- Oil American Petroleum Institute (API) gravity at the well site, γo.

See the memo in the docket titled, "Technical Development of the Low Pressure Well Equation for Assessing REC Feasibility at Hydraulically Fractured Oil and Gas Wells" at **https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7617** for a detailed description of how to apply the low pressure well equation along with a sample calculation.

A.4 Use of Artificial Lift Equipment

If you must use artificial lift equipment at your well to lift the fracture fluids to the surface, the well qualifies as a low pressure well. You will need to keep a record to document that this is the case and submit that documentation in the initial annual report for the well [§60.5420b(b)(2)(iii) and §60.5420b(c)(1)(vii)]

If you do not need to use artificial lift equipment for flowback, your well still may qualify as a low pressure well based on the static pressure at the wellhead.

Appendix B: Appendix K Overview

40 CFR part 60, appendix K (Appendix K) is a protocol that describes how to perform leak detection surveys when using an OGI camera. The camera type and manufacturer are not specified in the protocol, but the camera used must meet certain specifications and performance criteria. One of the criteria is to ensure that the camera can "see" the compounds in the gas that may leak, which is determined using camera response factors. Response factors can be obtained through peer-reviewed publications or by the method described in Annex 1 of Appendix K.

Because field conditions have the potential to impact the ability of the OGI camera operator to detect a leak, an operating envelope must be established for field use of the OGI camera. Imaging during leak surveys must be performed under conditions within the boundaries of the operating envelope. Operating envelopes are specific to an OGI camera model, and may be developed by the owner or operator, the camera manufacturer, or a third party. To develop the operating envelope, test gases are released at a steady rate, while the viewing distance, delta-T (the difference in temperature between the leaked gas and the surrounding background), and wind speed are varied to determine the conditions under which a panel of OGI camera operators can see the test gas leak.

Each site must have a monitoring plan that describes the procedures for conducting a monitoring survey, although the same monitoring plan can be used for multiple sites. The monitoring plan must describe the daily verification check procedures, how the camera operator will ensure that surveys are only conducted under appropriate conditions, how the operator will ensure that an adequate delta-T is always present, the methodology used to ensure all regulated components are monitored, provisions for operator rest breaks, how surveys and leaks will be documented, and quality assurance provisions. The monitoring plan must also describe how components are viewed with the camera. At a minimum, components must be viewed from at least two angles, for a minimum time of 10 seconds for simple scenes or 2 seconds per component in the scene if the scene is more complex.

The facility or company performing the OGI surveys must also have a training plan which ensures and monitors the proficiency of the OGI camera operators. Training must include classroom instruction (both initially and biennially) 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. Training must also include field training. The initial field training must include at least 30 hours with an experienced senior camera operator, followed by a final 2-hour field test. All camera operators must also be audited on a semiannual basis to ensure ongoing competence with the OGI camera. These audits are two hours long and may occur either through comparative monitoring

or video review. Camera operators who fail an audit must go through retraining, which includes a discussion of how to improve techniques, a minimum of 16 hours of field training with an experienced senior camera operator, and a final field test. If a camera operator fails two consecutive audits, the camera operator must repeat the initial training. 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. If an OGI camera operator has not conducted a monitoring survey in over 12 months, then the operator must complete the retraining requirements.

Appendix C: Control Device Monitoring Requirements

This appendix summarizes the control device parametric monitoring requirements for specific control devices in subpart OOOOb. Please see section 14.6 of this guide for an overview of the requirements for continuous parametric monitoring systems (CPMS) used to monitor the parameters.

There are two categories of control devices for which subpart OOOOb includes monitoring requirements: combustion devices and recovery devices. There are four types of combustion devices for which the monitoring requirements are somewhat different: ECDs, flares, boilers and process heaters, and catalytic vapor incinerators. Further, for ECDs, the monitoring requirements vary depending on whether the ECD is:

- An ECD where the combustion zone temperature is an indicator of destruction efficiency,
- An ECD where the combustion zone temperature is not an indicator of destruction efficiency,
- An ECD that is tested by the manufacturer.

The monitoring requirements for these combustion devices are summarized in Tables C-1 through C-5.

The two types of recovery devices for which subpart OOOOb includes monitoring requirements are condensers and carbon adsorbers. The monitoring requirements for these devices are summarized in Table C-1.

Table C-1. Overview of Parametric Monitoring for Enclosed Combustor Devices Where the Combustion Zone Temperature is an Indicator of Destruction Efficiency (Device Not Tested by the Manufacturer)

Requirement	Associated Monitoring Requirement(s)
Operate at or above the minimum temperature established during the most recent performance test [§60.5412b(a)(1)(ii)]	➢ Establish the minimum operating parameter value based on values measured during the performance test [§60.5417b(f)(1)(i)] ➢ Each continuous parameter monitoring system must measure data values at least once every hour and record the values for each parameter. [§60.5417b(c)(1)] ➢ You must prepare a monitoring plan that covers each control device for affected facilities within each company-defined area. [§60.5417b(c)(2)] ➢ 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. (1) . . . a temperature monitoring device equipped with a continuous recorder. . . [§60.5417b(d)]
Operate each ECD at or below the maximum inlet gas flow rate established in accordance with §60.5417b(f). [a] [§60.5412b(a)(1)(vi)]	➢ Establish the maximum inlet flow rate based on values measured during the performance test. [§60.5417b(f)(1)(i)] ➢ Use a continuous parameter monitoring system for measuring the flow of gas to the ECD. 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 the monitoring requirement. [§60.5417b(d)(8)(iv)] [b] ➢ 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. [§60.5417b(c)(1)] ➢ You must prepare a monitoring plan that covers each control device for affected facilities within each company-defined area. [§60.5417b(c)(2)]

Requirement	Associated Monitoring Requirement(s)
Operate the ECD at or above the minimum inlet gas flow rate established in accordance with §60.5417b(f). [§60.5412b(a)(1)(vii)]	➢ Establish the minimum inlet flow rate based on values measured during the performance test or you may establish the minimum inlet flow rate based on control device manufacturer recommendations. [§60.5417b(f)(1)(i)] ➢ Use a continuous parameter monitoring system for measuring the flow of gas to the ECD. 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 the monitoring requirement. [§60.5417b(d)(8)(iv)] [b] ➢ Each continuous parameter monitoring system must measure data values at least once every hour and record the values for each parameter. [§60.5417b(c)(1)] ➢ You must prepare a monitoring plan that covers each control device for affected facilities within each company-defined area. [§60.5417b(c)(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. [§60.5415b(f)(1)(viii)(A)(1)]	➢ 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. [§60.5412b(a)(1)(viii)] ➢ 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. [§60.5417b(c)(1)] ➢ 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. [§60.5417b(f)(1)(i)]

Requirement	Associated Monitoring Requirement(s)
You must operate the ECD with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. [§60.5412b(a)(1)(ix)]	➢ A visible emissions test using section 11 of 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 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). [§60.5412b(a)(1)(ix)] ➢ 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 or be monitored according to §60.5417b(h). [§60.5412b(a)(1)(ix)]
You must conduct periodic OGI and AVO inspections to ensure proper operation. [§60.5415b(f)(1(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 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. [§60.5415b(f)(1(x)] ➢ During each inspection conducted under §60.5397b using AVO, you must observe each ECD 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. [§60.5415b(f)(1(x)]

a. An ECD with pressure-assisted burner tips does not have to meet a maximum inlet gas flow rate.

b. §60.5417b(d)(8)(iv)(A) through (E) include exemptions and alternatives for this requirement.

Table C-2. Overview of Parametric Monitoring for Enclosed Combustor Devices Where the Combustion Zone Temperature is NOT an Indicator of Destruction Efficiency (Device Not Tested by the Manufacturer)

Requirement	Associated Monitoring Requirement(s)
Maintain the net heating value (NHV) or of the gas sent to the ECD at or above the applicable limits. [§60.5412b(a)(1)(iv)(A) through (D)] (A) For non-assisted or pressure-assisted: NHV at or above 200 Btu/scf. (B) For pressure-assisted burner tips: NHV at or above 800 Btu/scf. (C) For steam-assisted and air-assisted enclosed combustion devices: combustion zone NHV (NHV_{cz}) at or above 270 Btu/scf. (D) For devices with perimeter assist air: NHV dilution parameter (NHV_{dil}) at or above 22 Btu/scf. [a]	➢ Each continuous parameter monitoring system must measure data values at least once every hour and record the values for each parameter. [§60.5417b(c)(1)] ➢ You must prepare a monitoring plan that covers each control device for affected facilities within each company-defined area. [§60.5417b(c)(2)] ➢ 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. [§60.5417b(d)] ➢ Determine the NHV of the inlet gas to the ECD at standard conditions. Note: If the only inlet gas stream is associated gas, this requirement does not apply. [§60.5417b(d)(8)] • Continuously monitor using (A) a calorimeter, (B) a gas chromatograph, (C) a mass spectrometer, (D) a grab sampling system capable of collecting an evacuated canister sample every 8 hours. [§60.5417b(d)(8)(ii)] ***OR*** • For an unassisted or pressure-assisted device or a device that uses only perimeter assist air, continuously monitor or collect a sample twice daily for 14 consecutive operating days, then subsequently collect three samples of the inlet gas to the device at least once every 5 years thereafter. [§60.5417b(d)(8)(iii)]

Requirement	Associated Monitoring Requirement(s)
Operate each ECD at or below the maximum inlet gas flow rate established in accordance with §60.5417b(f) [b] [§60.5412b(a)(1)(vi)]	➢ Establish the maximum inlet flow rate based on values measured during the performance test. [§60.5417b(f)(1)(i)] ➢ Use a continuous parameter monitoring system for measuring the flow of gas to the ECD. 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 the monitoring requirement. [§60.5417b(d)(8)(iv)] [c] ➢ 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. [§60.5417b(c)(1)] ➢ You must prepare a monitoring plan that covers each control device for affected facilities within each company-defined area. [§60.5417b(c)(2)]
Operate the ECD at or above the minimum inlet gas flow rate established in accordance with §60.5417b(f). [§60.5412b(a)(1)(vii)]	➢ Establish the minimum inlet flow rate based on values measured during the performance test or you may establish the minimum inlet flow rate based on control device manufacturer recommendations. [§60.5417b(f)(1)(i)] ➢ Use a continuous parameter monitoring system for measuring the flow of gas to the ECD. 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 the monitoring requirement. [§60.5417b(d)(8)(iv)] [c] ➢ 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. [§60.5417b(c)(1)] ➢ You must prepare a monitoring plan that covers each control device for affected facilities within each company-defined area. [§60.5417b(c)(2)]

Requirement	Associated Monitoring Requirement(s)
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. [§60.5415b(f)(1)(viii)(A)(1)]	➢ 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. [§60.5412b(a)(1)(vii)] ➢ 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. [§60.5417b(c)(1)] ➢ 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. [§60.5417b(d)(8)(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. [§60.5417b(f)(1)(i)]

Requirement	Associated Monitoring Requirement(s)
You must operate the ECD with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. [§60.5412b(a)(1)(ix)]	➢ A visible emissions test using section 11 of 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 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). [§60.5412b(a)(1)(ix)] ➢ 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 or be monitored according to §60.5417b(h). [§60.5412b(a)(1)(ix)]
You must conduct periodic OGI and AVO inspections to ensure proper operation. [§60.5415b(f)(1(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 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. [§60.5415b(f)(1(x)] ➢ During each inspection conducted under §60.5397b using AVO, you must observe each ECD 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. [§60.5415b(f)(1(x)]

a. For an ECD with perimeter assist air where the effective diameter of the burner tip is less than 9 inches.

b. An ECD with pressure-assisted burner tips does not have to meet a maximum inlet gas flow rate.

c. §60.5417b(d)(8)(iv)(A) through (E) include exemptions and alternatives for this requirement.

Table C-3. Overview of Parametric Monitoring for Enclosed Combustor Devices Tested by the Manufacturer

Requirement	Associated Monitoring Requirement(s)
Operate each ECD at or below the maximum inlet gas flow rate specified by the manufacturer. [§60.5412b(a)] introductory paragraph [§60.5413b(e)(1))]	➢ Establish the maximum inlet flow rate according to manufacturer recommendations. [§60.5417b(f)(1)(iii)] ➢ Use a continuous parameter monitoring system for measuring the flow of gas to the ECD. 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 the monitoring requirement. [§60.5417b(d)(8)(iv)] [a] ➢ 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. [§60.5417b(c)(1)] ➢ You must prepare a monitoring plan that covers each control device for affected facilities within each company-defined area. [§60.5417b(c)(2)]
Operate the combustion control device at or above the minimum inlet gas flow rate specified by the manufacturer. [§60.5412b(a) introductory paragraph] [§60.5413b(e)(1))]	➢ Establish the minimum inlet flow rate according to manufacturer recommendations. [§60.5417b(f)(1)(iii)] ➢ Use a continuous parameter monitoring system for measuring the flow of gas to the ECD. 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 the monitoring requirement. [§60.5417b(d)(8)(iv)] [a] ➢ Each continuous parameter monitoring system must measure data values at least once every hour and record the values for each parameter. [§60.5417b(c)(1)] ➢ You must prepare a monitoring plan that covers each control device for affected facilities within each company-defined area. [§60.5417b(c)(2)]

Requirement	Associated Monitoring Requirement(s)
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. [§60.5412b(a) introductory paragraph] [§60.5413b(e)(2)]	➢ 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. [§60.5417b(c)(1)] ➢ 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. [§60.5417b(f)(1)(i)]
You must operate the ECD with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. [§60.5412b(a) introductory paragraph] [§60.5413b(e)(3))]	➢ A visible emissions test using section 11 of 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 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). [§60.5413b(e)(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 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 or be monitored according to §60.5417b(h). [§60.5413b(e)(4) and (5)]

Requirement	Associated Monitoring Requirement(s)
Comply with the applicable NHV limit specified in §60.5412b(a)(1)(iv)(A) through (D). [§60.5413b(e)(10)] (A) For non-assisted or pressure-assisted: NHV at or above 200 Btu/scf. (B) For pressure-assisted burner tips: NHV at or above 800 Btu/scf. (C) For steam-assisted and air-assisted enclosed combustion devices: combustion zone NHV (NHV_{cz}) at or above 270 Btu/scf. (D) For devices with perimeter assist air: NHV dilution parameter (NHV_{dil}) at or above 22 Btu/scf. [b]	➢ Each continuous parameter monitoring system must measure data values at least once every hour and record the values for each parameter. [§60.5417b(c)(1)] ➢ You must prepare a monitoring plan that covers each control device for affected facilities within each company-defined area. [§60.5417b(c)(2)] ➢ 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. [§60.5417b(d)] ➢ Determine the NHV of the inlet gas to the ECD at standard conditions. Note: If the only inlet gas stream is associated gas, this requirement does not apply. [§60.5417b(d)(8)] • Continuously monitor using (A) a calorimeter, (B) a gas chromatograph, (C) a mass spectrometer, (D) a grab sampling system capable of collecting an evacuated canister sample every 8 hours. [§60.5417b(d)(8)(ii)] ***OR*** • For an unassisted or pressure-assisted device or a device that uses only perimeter assist air, continuously monitor or collect a sample twice daily for 14 consecutive operating days, then subsequently collect three samples of the inlet gas to the device at least once every 5 years thereafter. [§60.5417b(d)(8)(iii)]

Requirement	Associated Monitoring Requirement(s)
You must conduct periodic OGI and AVO inspections to ensure proper operation. [§60.5415b(f)(1(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 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. [§60.5415b(f)(1(x)] ➢ During each inspection conducted under §60.5397b using AVO, you must observe each ECD 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. [§60.5415b(f)(1(x)]

a. §60.5417b(d)(8)(iv)(A) through (E) include exemptions and alternatives for this requirement.

b. For an ECD with perimeter assist air where the effective diameter of the burner tip is less than 9 inches.

Table C-4. Overview of Parametric Monitoring for Flares

Requirement	Associated Monitoring Requirement(s)
Maintain the net heating value (NHV) or of the gas sent to the flare at or above the applicable limits. [§60.5412b(a)(3)(i) through (iv)] (i) For non-assisted or pressure-assisted: NHV at or above 200 Btu/scf. (ii) For pressure-assisted burner tips: NHV at or above 800 Btu/scf. (iii) For steam-assisted and air-assisted flares: combustion zone NHV (NHV_{cz}) at or above 270 Btu/scf. (iv) For flares with perimeter assist air: NHV dilution parameter (NHV_{dil}) at or above 22 Btu/scf. [a]	➢ Each continuous parameter monitoring system must measure data values at least once every hour and record the values for each parameter. [§60.5417b(c)(1)] ➢ You must prepare a monitoring plan that covers each control device for affected facilities within each company-defined area. [§60.5417b(c)(2)] ➢ 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. [§60.5417b(d)] ➢ Determine the NHV of the inlet gas to the flare at standard conditions. Note: If the only inlet gas stream is associated gas, this requirement does not apply. [§60.5417b(d)(8)] • Continuously monitor using (A) a calorimeter, (B) a gas chromatograph, (C) a mass spectrometer, (D) a grab sampling system capable of collecting an evacuated canister sample every 8 hours. [§60.5417b(d)(8)(ii)] ***OR*** • For an unassisted or pressure-assisted flares or a device that uses only perimeter assist air, continuously monitor or collect a sample twice daily for 14 consecutive operating days, then subsequently collect three samples of the inlet gas to the device at least once every 5 years thereafter. [§60.5417b(d)(8)(iii)]

Requirement	Associated Monitoring Requirement(s)
Comply with the flare tip velocity limits in §60.18(b). [b] [§60.5412b(a)(3)(v)]	➢ Use a continuous parameter monitoring system for measuring the flow of gas to the 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. [c] [§60.5417b(d)(8)(iv)]
Operate the flare at or above the minimum inlet gas flow rate established based on manufacturer recommendations [§60.5412b(a)(3)(vi)]	➢ Use a continuous parameter monitoring system for measuring the flow of gas to the 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 the monitoring requirement. [§60.5417b(d)(8)(iv)] [c] ➢ 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. [§60.5417b(c)(1)] ➢ You must prepare a monitoring plan that covers each control device for affected facilities within each company-defined area. [§60.5417b(c)(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. [§60.5415b(f)(1)(viii)(A)(1)]	➢ 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. [§60.5412b(a)(3)(viii)] ➢ 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. [§60.5417b(c)(1)] ➢ 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. [§60.5417b(d)(8)(i)]

Requirement	Associated Monitoring Requirement(s)
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. [§60.5412b(a)(3)(vii)]	➢ You must conduct the compliance determination with the visible emission limits using Method 22 of appendix A-7 of this part, or you must monitor the flare according to §60.5417b(h). [§60.5412b(a)(3)(vii)]
You must conduct periodic OGI and AVO inspections to ensure proper operation. [§60.5415b(f)(1(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 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. [§60.5415b(f)(1(x)] ➢ During each inspection conducted under §60.5397b using AVO, you must observe each 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. [§60.5415b(f)(1(x)]

a. An ECD with pressure-assisted burner tips does not have to meet a maximum inlet gas flow rate.

b. The maximum flare tip velocity limits do not apply for pressure-assisted flares.

c. Paragraphs §60.5417b(d)(8)(iv)(A) through (E) include exemptions and alternatives for this requirement.

Table C-5. Overview of Parametric Monitoring for Boilers, Process Heaters, and Catalytic Incinerators

Is your combustion device…	Requirement	Associated Monitoring Requirement(s)
A boiler or process heater	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. [60.5412b(a)(1)(iii)]	N/A
A catalytic vapor incinerator	➢ Operate the catalytic vapor incinerator at or above the minimum temperature of the catalyst bed inlet. [60.5412b(a)(1)(v)] ➢ Operate 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). [60.5412b(a)(1)(v)] ➢ 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). [60.5415b(f)(1)(vii)(E)]	➢ Each continuous parameter monitoring system must measure data values at least once every hour and record the values for each parameter. [§60.5417b(c)(1)] ➢ You must prepare a monitoring plan that covers each control device for affected facilities within each company-defined area. [§60.5417b(c)(2)] ➢ 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. [§60.5417b(d)] ➢ Install, calibrate, operate, and maintain 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. [60.5417b(d)(2)]

Figure C-1. Overview of Parametric Monitoring for Vapor Recovery Devices [§§60.5412b(a)(2) and (c), 60.5415b(f), and 60.5471b(d)]