

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA-HQ-OAR-2021-0317; FRL-8510-04-OAR]

RIN 2060-AV16

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Supplemental notice of proposed rulemaking.

SUMMARY: The EPA is issuing this supplemental proposal to update, strengthen, and expand the standards proposed on November 15, 2021 (November 2021 proposal), which are intended to significantly reduce emissions of greenhouse gases (GHGs) and other harmful air pollutants from the Crude Oil and Natural Gas source category. First, the EPA proposes standards for certain sources that were not addressed in the November 2021 proposal. Second, the EPA proposes revisions that strengthen standards for sources of leaks, provide greater flexibility to use innovative advanced detection methods, and establish a super emitter response program. Third, the EPA proposes to modify and refine certain elements of the proposed standards in response to information submitted in public comments on the November 2021 proposal. Finally, the EPA proposes details of the timelines and other implementation requirements that apply to states to limit methane pollution from existing designated facilities in the source category under the Clean Air Act (CAA).

DATES:

Comments.

Comments must be received on or before February 13, 2023. Under the Paperwork Reduction Act (PRA), OMB is required to make a decision concerning the collections of information contained in the proposed rule between 30 and 60 days after publication and submission to OMB. A comment to OMB is best assured of consideration if the Office of Management and Budget (OMB) receives it on or before January 5, 2023.

Public hearing. The EPA will hold a virtual public hearing on January 10, 2023, and January 11, 2023. See **SUPPLEMENTARY INFORMATION** for information on the hearing.

ADDRESSES: You may send comments, identified by Docket ID No. EPA-HQ-

OAR-2021-0317 by any of the following methods:

- **Federal eRulemaking Portal:** <https://www.regulations.gov/> (our preferred method). Follow the online instructions for submitting comments.
- **Email:** a-and-r-docket@epa.gov. Include Docket ID No. EPA-HQ-OAR-2021-0317 in the subject line of the message.
- **Fax:** (202) 566-9744. Attention Docket ID No. EPA-HQ-OAR-2021-0317.
- **Mail:** U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA-HQ-OAR-2021-0317, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.

• **Hand/Courier Delivery:** EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operation are 8:30 a.m.-4:30 p.m., Monday-Friday (except Federal holidays).

Instructions. All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to <https://www.regulations.gov/>, including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the "Public Participation" heading of the **SUPPLEMENTARY INFORMATION** section of this document. For further information on EPA Docket Center services and the current status, please visit us online at <https://www.epa.gov/dockets>.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Ms. Karen Marsh, Sector Policies and Programs Division (E143-05), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541-1065; fax number: (919) 541-0516; and email address: marsh.karen@epa.gov or Ms. Amy Hambrick, Sector Policies and Programs Division (E143-05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541-0964; fax number: (919) 541-0516; email address: hambrick.amy@epa.gov.

SUPPLEMENTARY INFORMATION:

Participation in virtual public hearing. The public hearing will be held via virtual platform on January 10, 2023, and January 11, 2023, and will convene at 10:00 a.m. Eastern Time (ET) and conclude at 8:00 p.m. ET each day. On each hearing day, the EPA may close a

session 15 minutes after the last pre-registered speaker has testified if there are no additional speakers. The EPA will announce further details at <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry>. If the EPA receives a high volume of registrations for the public hearing, we may continue the public hearing on January 12, 2023. The EPA does not intend to publish a document in the **Federal Register** announcing the potential addition of a third day for the public hearing or any other updates to the information on the hearing described in this document. Please monitor <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry> for any updates to the information described in this document, including information about the public hearing. For information or questions about the public hearing, please contact the public hearing team at (888) 372-8699 or by email at SPPDpublichearing@epa.gov.

The EPA will begin pre-registering speakers for the hearing no later than 1 business day following the publication of this document in the **Federal Register**. The EPA will accept registrations on an individual basis. To register to speak at the virtual hearing, follow the directions at <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry> or contact the public hearing team at (888) 372-8699 or by email at SPPDpublichearing@epa.gov. The last day to pre-register to speak at the hearing will be January 5, 2023. Prior to the hearing, the EPA will post a general agenda that will list pre-registered speakers in approximate order at: <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry>.

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule.

Each commenter will have 4 minutes to provide oral testimony. The EPA encourages commenters to provide the EPA with a copy of their oral testimony by submitting the text of your oral testimony as written comments to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral testimony and supporting information presented at the public hearing.

If you require the services of an interpreter or a special accommodation

such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by December 13, 2022. The EPA may not be able to arrange accommodations without advanced notice.

Docket. The EPA has established a docket for this rulemaking under Docket ID No. EPA-HQ-OAR-2021-0317. All documents in the docket are listed in <https://www.regulations.gov/>. Although listed, some information is not publicly available, e.g., Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy. With the exception of such material, publicly available docket materials are available electronically in <https://www.regulations.gov/>.

Instructions. Direct your comments to Docket ID No. EPA-HQ-OAR-2021-0317. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at <https://www.regulations.gov/>, including any personal information provided, unless the comment includes information claimed to be CBI or other information whose disclosure is restricted by statute. Do not submit electronically to <https://www.regulations.gov/> any information that you consider to be CBI or other information whose disclosure is restricted by statute. This type of information should be submitted as discussed below.

The EPA may publish any comment received to its public docket. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (i.e., on the Web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit <https://www.epa.gov/dockets/commenting-epa-dockets>.

The <https://www.regulations.gov/> website allows you to submit your comment anonymously, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through <https://www.regulations.gov/>, your email

address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any digital storage media you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at <https://www.epa.gov/dockets>.

Submitting CBI. Do not submit information containing CBI to the EPA through <https://www.regulations.gov/>. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, note the docket ID, mark the outside of the digital storage media as CBI and identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in the *Instructions* section of this document. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI and note the docket ID. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2.

Our preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (e.g., Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqpscbi@epa.gov, and as described in the preceding paragraph, should include clear CBI markings and note the docket ID. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqpscbi@epa.gov to

request a file transfer link. If sending CBI information through the postal service, please send it to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA-HQ-OAR-2021-0317. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

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

AMEL alternate means of emissions limitation
ANSI American National Standards Institute
APA Administrative Procedures Act
API American Petroleum Institute
ASME American Society of Mechanical Engineers
ASTM American Society for Testing and Materials
AVO audio, visual, and olfactory
AWP alternative work practice
BMP best management practices
boe barrels of oil equivalents
BSER best system of emission reduction
Btu/scf British thermal unit per standard cubic foot
°C degrees Centigrade
CAA Clean Air Act
CBI Confidential Business Information
CCR Code of Colorado Regulations
CDX EPA's Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
CH₄ methane
CO carbon monoxide
CO₂ carbon dioxide
CO₂ Eq. carbon dioxide equivalent
CRA Congressional Review Act
CVS closed vent systems
CWA Clean Water Act
D.C. Circuit U.S. Court of Appeals for the District of Columbia Circuit
DOE Department of Energy
EAV equivalent annual value
EDF Environmental Defense Fund
EG emission guidelines
EIA U.S. Energy Information Administration
EJ environmental justice
E.O. Executive Order
EPA Environmental Protection Agency
ESD emergency shutdown devices
°F degrees Fahrenheit
FEAST Fugitive Emissions Abatement Simulation Toolkit
FR Federal Register
FRFA final regulatory flexibility analysis
g/hr grams per hour
GHG greenhouse gas
GHGI Inventory of U.S. Greenhouse Gas Emissions and Sinks
GHGRP Greenhouse Gas Reporting Program

HAP hazardous air pollutant(s)
 ICR information collection request
 IRFA initial regulatory flexibility analysis
 IWG Interagency Working Group on the Social Cost of Greenhouse Gases
 kg kilograms
 low-e low emission
 LDAR leak detection and repair
 Mcf thousand cubic feet
 METEC Methane Emissions Technology Evaluation Center
 MW megawatt
 NAAQS National Ambient Air Quality Standards
 NAICS North American Industry Classification System
 NDE no detectable emissions
 NESHAP National Emissions Standards for Hazardous Air Pollutants
 NGO non-governmental organization
 NHV net heating value
 NO_x nitrogen oxides
 NSPS new source performance standards
 NTTAA National Technology Transfer and Advancement Act
 OAQPS Office of Air Quality Planning and Standards
 OGI optical gas imaging
 OMB Office of Management and Budget
 PM_{2.5} particulate matter with a diameter of 2.5 micrometers or less
 ppm parts per million
 PRA Paperwork Reduction Act
 PTE potential to emit
 PV present value
 REC reduced emissions completion
 RFA Regulatory Flexibility Act
 RIA regulatory impact analysis
 RULOF remaining useful life and other factors
 SBAR Small Business Advocacy Review
 SC-CH₄ social cost of methane
 SC-GHG social cost of greenhouse gases
 scf standard cubic feet
 scfh standard cubic feet per hour
 scfm standard cubic feet per minute
 SIP state implementation plan
 SO₂ sulfur dioxide
 SPeCS State Planning Electronic Collaborative System
 tpy tons per year
 the court U.S. Court of Appeals for the District of Columbia Circuit
 TAR Tribal Authority Rule
 TIP tribal implementation plan
 TSD technical support document
 UMRA Unfunded Mandates Reform Act
 U.S. United States
 VCS Voluntary Consensus Standards
 VOC volatile organic compounds
 VRU vapor recovery unit

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I. Executive Summary

A. Purpose of the Regulatory Action

On November 15, 2021, the EPA published a proposed rule (November 2021 proposal) that was intended to mitigate climate-destabilizing pollution and protect human health by reducing greenhouse gas (GHG) and VOC emissions from the Oil and Natural Gas Industry,¹ specifically the Crude Oil and Natural Gas source category.² A wide range of stakeholders, as well as state and tribal governments, submitted public comments on the November 2021 proposal. Over 470,000 public comments were submitted. Many commenters representing diverse perspectives expressed general support for the proposal and requested that the EPA further strengthen the proposed standards and make them more comprehensive. Other commenters highlighted implementation or cost concerns related to elements of the November 2021 proposal or provided specific data and information that the EPA was able to use to refine or revise several of the standards included in the November 2021 proposal.

In the November 2021 proposal, the EPA proposed new standards and emission guidelines under CAA section 111 which would be included in 40 CFR part 60 at subpart OOOOb (NSPS OOOOb) and subpart OOOOc (EG OOOOc). The purpose of this supplemental proposed rulemaking is to strengthen, update, and expand the proposed standards for certain emissions sources, including: (1) To reduce emissions from the source category more comprehensively by adding proposed standards for certain sources that were not addressed in the November 2021 proposal, revising the

¹ The EPA characterizes the Oil and Natural Gas Industry operations as being generally composed of four segments: (1) Extraction and production of crude oil and natural gas ("oil and natural gas production"), (2) natural gas processing, (3) natural gas transmission and storage, and (4) natural gas distribution.

² The EPA defines the Crude Oil and Natural Gas source category to mean: (1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and (2) natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station, commonly referred to as the "city-gate."

proposed requirements for fugitive emissions monitoring and repair, and establishing a super-emitter response program; (2) to encourage the deployment of innovative technologies and techniques for detecting and reducing methane emissions by providing additional options for the use of advanced monitoring; (3) to modify and refine certain elements of the proposed standards in response to concerns and information identified in an initial review of public comments on the November 2021 proposal; and (4) to provide additional information not included in the November 2021 proposal for public comment, such as the content for the new subparts that reflects the proposed standards and emission guidelines, and details of the timelines and other requirements that apply to states as they develop state plans to implement the emission guidelines.

In the November 2021 proposal, the EPA performed a comprehensive analysis of the available data from emission sources in the Crude Oil and Natural Gas source category and the latest available information on control measures and techniques to identify achievable, cost-effective measures to significantly reduce methane and VOC emissions, consistent with the requirements of section 111 of the CAA.³ This supplemental proposal builds on that analysis to apply additional information and data provided to the Agency since the November 2021 proposal to identify areas to further strengthen standards, such as measures to address large emissions events, commonly referred to as super-emitters. If finalized and implemented, the proposed actions in this rulemaking, as detailed in the November 2021 proposal and this supplemental proposal, would lead to significant and cost-effective reductions in climate and health-harming pollution and encourage the continued development and deployment of innovative technologies to further reduce this pollution in the Crude Oil and Natural Gas source category.

This supplemental proposal comprises distinct actions:

- Update, strengthen, and/or expand on the standards proposed in November 2021 under CAA section 111(b) for methane and VOC emissions from new, modified, and reconstructed facilities that commenced construction, reconstruction, or modification after November 15, 2021,
- Update, strengthen, and/or expand the presumptive standards proposed in

November 2021 as part of the CAA section 111(d) emission guidelines for methane emissions from existing designated facilities that commenced construction, reconstruction, or modification on or before November 15, 2021,

- And establish the implementation requirements for states to limit methane pollution from existing designated facilities in the source category under CAA section 111(d).

The Oil and Natural Gas Industry is the United States' largest industrial emitter of methane, a highly potent GHG.⁴ Methane and VOC emissions from the Crude Oil and Natural Gas source category result from a variety of industry operations across the supply chain. As natural gas moves through the necessarily interconnected system of exploration, production, storage, processing, and transmission that brings it from wellhead to commerce, emissions primarily result from intentional venting, unintentional gas carry-through (e.g., vortexing from separator drain, improper liquid level settings, liquid level control valve on an upstream separator or scrubber not seating properly at the end of an automated liquid dumping event, inefficient separation of gas and liquid phases occurring upstream of tanks allowing some gas carry-through), routine maintenance, unintentional fugitive emissions, flaring, malfunctions, abnormal process conditions, and system upsets. These emissions are associated with a range of specific equipment and practices, including leaking valves, connectors, and other components at well sites and compressor stations; leaks and vented emissions from controlled storage vessels; releases from natural gas-driven pneumatic pumps and controllers; liquids unloading at well sites; and venting or under-performing flaring of associated gas from oil wells. Technical innovations have produced a range of technologies and best practices to monitor, eliminate or minimize these emissions, which in many cases have the benefit of simultaneously reducing multiple pollutants and recovering saleable product. These technologies and best practices have been deployed by individual oil and natural gas companies, required by state regulations, reflected in regulations issued by the EPA and other Federal

agencies, or utilized by various non-industry groups and research teams.

In developing this supplemental proposal, the EPA applied the latest available information to refine or supplement the analyses presented in the November 2021 proposal. This latest information provided additional insights into lessons learned from states' regulatory efforts, the emission reduction efforts of leading companies, the continued development of new and developing technologies, and peer-reviewed research from emission measurement campaigns across the United States (U.S.). As stated in the November 2021 proposal, the EPA solicited comment on all aspects of the proposed standards and stated its intent to issue a supplemental proposal that revisited and refined certain provisions of that proposal in response to information provided by the public. This supplemental proposal does just that. For instance, the EPA sought input in the November 2021 proposal on multiple aspects of the proposed approach for fugitive emissions monitoring at well sites, including the baseline emission threshold and other criteria (such as the presence of specific types of malfunction-prone equipment) that should be used to determine whether a well site is required to undertake ongoing fugitive emissions monitoring. (86 FR 63115; November 15, 2021). After considering the comments and information received, this supplemental proposal includes a revised approach for fugitive emissions monitoring at well sites utilizing modeling to establish the proposed monitoring frequency and detection method for individual sites based on the presence of specific types of equipment. In contrast to the November 2021 proposal, this supplemental proposal would establish an obligation for all well sites to routinely monitor for fugitive emissions and repair leaks found—ranging from a quarterly audio, visual, and olfactory (AVO) inspection for single wellhead-only sites to quarterly optical gas imaging (OGI) inspections for any site with significant production equipment. This revised approach to addressing fugitive emissions from well sites also would carry the monitoring requirements through the entire life of the well site and would specify the requirements for ceasing monitoring following well closures when production from the entire well site has stopped. The EPA is seeking comments about labor requirements to implement these monitoring requirements.

⁴ Emissions from EPA (2022) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020. U.S. Environmental Protection Agency, EPA 430–R–22–003. <https://www.epa.gov/ghgemissions/draft-inventory-us-greenhouse-gas-emissions-and-sinks-1990-2020>.

³ 42 U.S.C. 7411.

Super-emitter emissions events⁵ were another key area in the November 2021 proposal for which the EPA solicited comment. (86 FR 63177; November 15, 2021). This supplemental proposal includes various standards that, when implemented by an owner or operator, could reduce or eliminate the occurrence of super-emitter emissions events, such as the inclusion of specific compliance assurance measures to ensure that flares are operating as designed with a continuously lit pilot. In addition, this supplemental notice proposes a super-emitter response program to trigger swift mitigation of super-emitter emissions events when they are identified through credible information provided by regulatory authorities or approved qualified third-party sources.

Content for the new subparts reflecting these proposed changes is available in the docket for this action (Docket ID No. EPA-HQ-OAR-2021-0317) and supplements the redline versions of NSPS OOOO and NSPS OOOOa provided in the November 2021 proposal (Docket ID Nos. EPA-HQ-OAR-2021-0317-0095 and EPA-HQ-OAR-2021-0317-0097). In addition, the EPA is providing an updated regulatory impact analysis (RIA) that seeks to account for the full impacts of these proposed actions.

Additionally, the EPA is seeking comment and information on the proposed provisions for the use of advanced methane measurement technologies for both periodic screening and continuous monitoring as an alternative to OGI. The revised proposal includes a matrix that provides various monitoring frequencies based on specific performance criteria a technology would need to meet in order to be used for periodic screening. In addition to this proposed matrix, this supplemental proposal includes provisions for requesting the use of alternative test method(s) that, where approved, could be used broadly for deploying these alternative technologies. Further, the EPA is proposing a framework for the use of continuous monitoring systems that provide a mass emissions rate with site-specific action levels based on changes in quarterly average emissions and on the detection of an acute large emission spike or event on a shorter term. Diverse stakeholders expressed strong interest in employing these new tools for methane

identification and quantification, particularly for super-emitters, and in the EPA's creation of a regime to promote and accommodate their development and use. This proposal provides an approach for fostering those alternatives, which could provide a template for future innovation-conducive regulatory standards. The EPA is also seeking comment on the detection limits of all monitoring and inspection requirements.

Throughout this action, unless noted otherwise, the EPA is requesting comments on all aspects of the supplemental proposal to enable the EPA to develop a final rule that, consistent with our responsibilities under section 111 of the CAA, achieves the greatest possible reductions in methane and VOC emissions while remaining achievable, cost effective, and conducive to technological innovation. Because this preamble includes comment solicitations/requests on several topics and issues, we have prepared a separate memorandum that presents these comment requests by section and topic as a guide to assist commenters in preparing comments. This memorandum can be obtained from the Docket for this action (see Docket ID No. EPA-HQ-OAR-2021-0317). The title of the memorandum is "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review—Supplemental Proposed Rule Summary of Comment Solicitations." It is not necessary to resubmit comments that were submitted for the November 2021 proposal.

B. Summary of the Major Provisions of the Regulatory Action

This supplemental proposal includes two distinct rulemaking actions under the CAA. First, the EPA is proposing specific changes to strengthen the proposed requirements under CAA section 111(b) for methane and VOC emissions from sources that commenced construction, modification, or reconstruction after November 15, 2021. These proposed revisions to strengthen the November 15, 2021, proposed standards of performance will be in a new subpart, NSPS OOOOb, and include proposed standards for emission sources previously not regulated for this source category.

Second, pursuant to CAA section 111(d), the EPA is proposing specific revisions to strengthen the first nationwide emission guideline (EG) for states to limit methane pollution from existing designated facilities in the Crude Oil and Natural Gas source

category. The proposed revisions to strengthen the November 15, 2021, proposed presumptive standards will be in a new subpart, EG OOOOc. The emissions guidelines (EG) are designed to inform states in the development, submittal, and implementation of state plans that are required to establish standards of performance for GHGs (in the form of limitations on methane) from their designated facilities in the Crude Oil and Natural Gas source category.

As CAA section 111(a)(1) requires, the standards of performance under section 111(b) and presumptive standards under section 111(d) being proposed in this action reflect "the degree of emission limitation achievable through the application of the best system of emission reduction (BSER) which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated."⁶ In this proposed supplemental rulemaking, we evaluated new data made available to the EPA and information provided from public comments on the November 2021 proposal to update the analyses and evaluate whether revisions to the proposed BSER should be considered. For any potential control measure evaluated in this action, as in the November 2021 proposal, the EPA evaluated the emission reductions achievable through these measures and employed multiple approaches to evaluate the reasonableness of control costs associated with the options under consideration. For example, in evaluating controls for reducing VOC and methane emissions from new sources, we considered a control measure's cost-effectiveness under both a "single pollutant cost-effectiveness" approach and a "multipollutant cost-effectiveness" approach, to appropriately reflect that the systems of emission reduction evaluated in this rule typically achieve reductions in multiple pollutants simultaneously and secure a multiplicity of climate and public health benefits. We also

⁶ The EPA notes that design, equipment, work practice or operational standards established under CAA section 111(h) (commonly referred to as "work practice standards") reflect the "best technological system of continuous emission reduction" and that this phrasing differs from the "best system of emission reduction" phrase in the definition of "standard of performance" in CAA section 111(a)(1). Although the differences in these phrases may be meaningful in other contexts, for purposes of evaluating the sources and systems of emission reduction at issue in this rulemaking, the EPA has applied these concepts in an essentially comparable manner because the systems of emission reduction the EPA evaluated are all technological.

⁵ In the November 2021 proposal, the EPA solicited comment on the use of information collected by communities and others to address large emissions events, which this supplemental proposal now defines as "super-emitter emissions events."

compared: (1) The capital costs that would be incurred through compliance with the proposed standards against the industry's current level of capital expenditures and (2) the annualized

costs against the industry's estimated annual revenues. For a detailed discussion of the EPA's consideration of this and other BSER statutory elements, please see section III.E of this preamble,

86 FR 63133; November 15, 2021, and 86 FR 63153; November 15, 2021. Table 1 summarizes the applicability dates for the four subparts that the EPA's November 2021 proposal included.

TABLE 1—APPLICABLE DATES FOR PROPOSED SUBPARTS ADDRESSED IN THIS PROPOSED ACTION

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 November 15, 2021.
40 CFR part 60, subpart OOOOb	New, modified, or reconstructed sources.	After November 15, 2021. ¹
40 CFR part 60, subpart OOOOc	Existing sources	On or before November 15, 2021. ²

¹ The standards for dry seal centrifugal compressors will apply to those for which construction, reconstruction, or modification commenced after December 6, 2022.

² The presumptive standards for dry seal centrifugal compressors will apply to those for which construction, reconstruction, or modification commenced on or before December 6, 2022.

1. Proposed Standards for New, Modified and Reconstructed Sources After November 15, 2021 (Proposed NSPS OOOOb)

As described in section IV of this preamble, the EPA is proposing several changes to the BSER and the standards for certain affected facilities based on a review of new data made available to the EPA and information provided in public comments. For the other standards proposed in the November 2021 proposal that generally remain unchanged in this action, we have provided further justifications or clarifications as needed based on the public comments and other additional information received, as described in section IV of this preamble. The proposed NSPS would apply to new, modified, and reconstructed emission sources across the Crude Oil and Natural Gas source category, including the production, processing, transmission, and storage segments, for which construction, reconstruction, or modification commenced after November 15, 2021, which is the date of publication of the proposed NSPS OOOOb. In addition, the EPA is proposing methane and VOC standards for one new emission source that is currently unregulated (*i.e.*, dry seal centrifugal compressors). Because standards for dry seal centrifugal compressors were not proposed in the November 2021 proposal, new, modified, and reconstructed dry seal centrifugal compressors are defined as those for which construction, reconstruction, or modification commenced after December 6, 2022.

In particular, this action proposes revisions to strengthen the proposed VOC and methane standards addressing fugitive emissions from well sites and

pneumatic pumps; generally leaves unchanged the proposed sulfur dioxide (SO₂) performance standard for sweetening units and the proposed VOC and methane performance standards for well completions, gas well liquids unloading operations, associated gas from oil wells, wet seal centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels, fugitive emissions from compressor stations, and equipment leaks at natural gas processing plants; and proposes new VOC and methane standards for dry seal centrifugal compressors previously not regulated. A summary of the proposed BSER determination and proposed NSPS for new, modified, and reconstructed sources (NSPS OOOOb) is presented in Table 2. See section IV of this preamble for a complete discussion of the proposed changes to the BSER determination and proposed NSPS requirements.

This proposal also includes provisions for the use of alternative test methods using advanced methane detection technologies that allow for periodic screening or continuous monitoring for fugitive emissions and emissions from covers and closed vent systems (CVS) used to route emissions to control devices. These proposed alternatives would allow for advanced screening technologies, which could be used to identify large emissions or “super-emitter emissions events” sooner than the proposed use of periodic OGI monitoring for fugitive emissions, covers on storage vessels, and CVS. Various studies using aerial monitoring techniques have identified large emissions from these types of sources. Finally, in order to ensure that super-emitter emissions events are identified and mitigated as quickly as possible, the EPA is proposing a super-emitter

response program where an owner or operator must investigate and take appropriate mitigation actions upon receiving certified notifications of detected emissions that are 100 kg/hr of methane or greater. See sections IV.A and IV.B of this preamble for a complete discussion of these proposed provisions.

2. Proposed EG for Sources Constructed Prior to November 15, 2021 (Proposed EG OOOOc)

As described in sections IV and V of this preamble, the EPA is proposing several changes to the BSER determinations and presumptive standards that were proposed under the authority of CAA section 111(d) in the November 2021 proposal. These changes are based on a review of new data made available to the EPA and information provided in public comments. In the November 2021 proposal the EPA proposed the first nationwide EG for GHG (in the form of methane limitations) for the Crude Oil and Natural Gas source category, including the production, processing, transmission, and storage segments (EG OOOOc).

This action proposes revisions to strengthen the proposed presumptive standards for methane addressing fugitive emissions from well sites, pneumatic controllers, pneumatic pumps, and wet seal centrifugal compressors; generally leaves unchanged the proposed methane presumptive standards for associated gas from oil wells, reciprocating compressors, storage vessels, fugitive emissions from compressor stations, and equipment leaks at natural gas processing plants; and proposes new methane presumptive standards for well liquids unloading operations and dry seal centrifugal compressors previously

not proposed to be regulated. A summary of the proposed BSER determination and proposed presumptive standards for EG OOOOc is presented in Table 3. See section IV of this preamble for a complete discussion of the proposed changes to the BSER determination and proposed presumptive standards.

This proposal also includes the same provisions described for NSPS OOOOb that allow for the use of alternative test methods using advanced methane detection technologies for periodic screening or continuous monitoring for fugitive emissions and emissions from covers and CVS used to route emissions to control devices. Finally, the EPA is also proposing a super-emitter response program, where an owner or operator that receives certified notifications of detected emissions that are 100 kg/hr or greater is obligated to take action to address those emissions. See sections IV.A and IV.B of this preamble for a complete discussion of these proposed provisions.

As stated in the November 2021 proposal,⁷ when the EPA establishes NSPS for a source category, the EPA is required to issue EG to reduce emissions of certain pollutants from existing sources in that same source category. In such circumstances, under CAA section 111(d), the EPA must issue regulations to establish procedures under which states submit plans to establish, implement, and enforce standards of performance for existing sources for certain air pollutants to which a Federal NSPS would apply if such existing source were a new source. Thus, the issuance of CAA section 111(d) final EG does not impose binding requirements directly on sources but instead provides

requirements for states in developing their plans. Although state plans bear the obligation to establish standards of performance, under CAA sections 111(a)(1) and 111(d), those standards of performance must reflect the degree of emission limitation achievable through the application of the BSER as determined by the Administrator. As provided in CAA section 111(d), a state may choose to take into account remaining useful life and other factors in applying a standard of performance to a particular source, consistent with the CAA, the EPA's implementing regulations, and the final EG.

In this supplemental proposal, the EPA is proposing changes to the BSER determinations and the degree of limitation achievable through application of the BSER for certain existing equipment, processes, and activities across the Crude Oil and Natural Gas source category. Those changes are discussed in section IV of this preamble. Section V of this preamble discusses the components of EG, including the steps, requirements, and considerations associated with the development, submittal, and implementation of state, tribal, and Federal plans, as appropriate. For the EG, the EPA is proposing to translate the degree of emission limitation achievable through application of the BSER (*i.e.*, level of stringency) into presumptive standards that states may use in the development of state plans for specific designated facilities. By doing this, the EPA has formatted the proposed EG such that if a state chooses to adopt these presumptive standards, once finalized, as the standards of performance in a state plan, the EPA

could approve such a plan as meeting the requirements of CAA section 111(d) and the finalized EG, if the plan meets all other applicable requirements. In this way, the presumptive standards included in the EG serve a function similar to that of a model rule,⁸ because they are intended to assist states in developing their plan submissions by providing states with a starting point for standards that are based on general industry parameters and assumptions. The EPA anticipates that providing these presumptive standards will create a streamlined approach for states in developing plans and the EPA in evaluating state plans. However, the EPA's action on each state plan submission is carried out via rulemaking, which includes public notice and comment. Inclusion of presumptive standards in the EG does not seek to pre-determine the outcomes of any future rulemaking.

Designated facilities located in Indian country would not be encompassed within a state's CAA section 111(d) plan. Instead, an eligible tribe that has one or more designated facilities located in its area of Indian country would have the opportunity, but not the obligation, to seek authority and submit a plan that establishes standards of performance for those facilities on its Tribal lands. If a tribe does not submit a plan, or if the EPA does not approve a tribe's plan, then the EPA has the authority to establish a Federal plan for that tribe. A summary of the proposed EG for existing sources (EG OOOOc) for the oil and natural gas sector is presented in Table 3. See sections IV and V of this preamble for a complete discussion of the proposed EG requirements.

TABLE 2—SUMMARY OF PROPOSED BSER AND PROPOSED STANDARDS OF PERFORMANCE FOR GHGs AND VOCs [NSPS OOOOb]

Affected source	Proposed BSER	Proposed standards of performance for GHGs and VOCs
Super-Emitters	Root cause analysis and corrective action following notification of super-emitter emissions event.	Root cause analysis and corrective action following notification of super-emitter emissions event.
Fugitive Emissions: Single Wellhead Only Well Sites and Small Well Sites.	Quarterly AVO inspections	Quarterly AVO inspections. Repair for indications of potential leaks within 15 days of inspection. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Multi-wellhead Only Well Sites (2 or more wellheads).	Quarterly AVO inspections AND	Quarterly AVO inspections. Repair for indications of potential leaks within 15 days of inspection.

⁷ See 86 FR 63117 (November 15, 2021).

⁸ The presumptive standards are not the same as a Federal plan under CAA section 111(d)(2). The

EPA has an obligation to promulgate a Federal plan if a state fails to submit a satisfactory plan. In such circumstances, the final EG and presumptive

standards would serve as a guide to the development of a Federal plan. See section VIII.F. for information on Federal plans.

TABLE 2—SUMMARY OF PROPOSED BSER AND PROPOSED STANDARDS OF PERFORMANCE FOR GHGS AND VOCs—
Continued
[NSPS OOOOb]

Affected source	Proposed BSER	Proposed standards of performance for GHGs and VOCs
Fugitive Emissions: Well Sites with Major Production and Processing Equipment and Centralized Production Facilities.	Monitoring and repair based on semiannual monitoring using OGI ² . Bimonthly AVO monitoring (<i>i.e.</i> , every other month). AND Well sites with specified major production and processing equipment: Monitoring and repair based on quarterly monitoring using OGI.	Semiannual OGI monitoring (Optional semi-annual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report. Bimonthly AVO inspections. Repair for indications of potential leaks within 15 days of inspection. AND Well sites with specified major production and processing equipment: Quarterly OGI monitoring. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Compressor Stations	Monthly AVO monitoring AND Monitoring and repair based on quarterly monitoring using OGI.	Monthly AVO monitoring. AND Quarterly OGI monitoring. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations on Alaska North Slope.	Monitoring and repair based on annual monitoring using OGI.	Annual OGI monitoring. (Optional annual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations.	(Optional) Screening, monitoring, and repair based on periodic screening using an advanced measurement technology instead of OGI monitoring.	(Optional) Alternative periodic screening with advanced measurement technology instead of OGI and AVO monitoring according to minimum detection sensitivity of technology.
Fugitive Emissions: Well Sites and Compressor Stations.	(Optional) Monitoring and repair based on using a continuous monitoring system instead of OGI monitoring.	(Optional) Alternative continuous monitoring system instead of OGI and AVO monitoring.
Storage Vessels: A Single Storage Vessel or Tank Battery with PTE ⁴ of 6 tpy or more of VOC and PTE of 20 tpy or more of methane.	Capture and route to a control device	95 percent reduction of VOC and methane.
Pneumatic Controllers: Natural gas-driven that Vent to the Atmosphere.	Use of zero-emissions controllers	VOC and methane emission rate of zero.
Pneumatic Controllers: Alaska (at sites where onsite power is not available—continuous bleed natural gas-driven).	Use of low-bleed pneumatic controllers	Natural gas bleed rate no greater than 6 scfh. ⁵
Pneumatic Controllers: Alaska (at sites where onsite power is not available—intermittent natural gas-driven).	Monitor and repair through fugitive emissions program.	OGI monitoring and repair of emissions from controller malfunctions.
Well Liquids Unloading	Employ techniques or technologies that eliminate methane and VOC emissions. If this is not feasible for safety or technical reasons, employ best management practices to minimize venting of emissions to the maximum extent possible.	Perform liquids unloading with zero methane or VOC emissions. If this is not feasible for safety or technical reasons, employ best management practices to minimize venting of emissions to the maximum extent possible.
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.	95 percent reduction of methane and VOC emissions.
Dry Seal Centrifugal Compressors (except for those located at well sites).	Conduct preventative maintenance and repair to maintain flow rate at or below 3 scfm ⁷ .	Volumetric flow rate of 3 scfm.

TABLE 2—SUMMARY OF PROPOSED BSER AND PROPOSED STANDARDS OF PERFORMANCE FOR GHGS AND VOCs—
Continued
[NSPS OOOOb]

Affected source	Proposed BSER	Proposed standards of performance for GHGs and VOCs
Reciprocating Compressors (except for those located at well sites).	Repair or replace the reciprocating compressor rod packing in order to maintain a flow rate at or below 2 scfm.	Volumetric flow rate of 2 scfm.
Pneumatic Pumps	Use of zero-emission pumps that are not powered by natural gas.	Methane and VOC emission rate of zero.
Well Completions: Subcategory 1 (non-wildcat and non-delineation wells).	Combination of REC ⁸ and the use of a completion combustion device.	Applies to each well completion operation with hydraulic fracturing. 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 on-site 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, 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 low-pressure wells).	Use of a completion combustion device	Applies to each well completion operation with hydraulic fracturing. 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.
Equipment Leaks at Natural Gas Processing Plants.	LDAR ⁹ with bimonthly OGI	LDAR with OGI following procedures in appendix K.
Oil Wells with Associated Gas	Route associated gas to a sales line. If access to a sales line is not available, the gas can be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent reduction in methane and VOC emissions.	Route associated gas to a sales line. If access to a sales line is not available, the gas can be used as an onsite fuel source or used for another useful purpose that a purchased fuel or raw material would serve. If demonstrated that a sales line and beneficial uses are not technically feasible, the gas can be routed to a flare or other control device that achieves at least 95 percent reduction in methane and VOC emissions.
Sweetening Units	Achieve SO ₂ emission reduction efficiency	Achieve required minimum SO ₂ emission reduction efficiency.

¹ tpy (tons per year).

² OGI (optical gas imaging).

³ ppm (parts per million).

⁴ PTE (potential to emit).

- ⁵ scfh (standard cubic feet per hour).
⁶ BMP (best management practices).
⁷ scfm (standard cubic feet per minute).
⁸ REC (reduced emissions completion).
⁹ LDAR (leak detection and repair).

TABLE 3—SUMMARY OF PROPOSED BSER AND PROPOSED PRESUMPTIVE STANDARDS FOR GHGS FROM DESIGNATED FACILITIES (EG OOOOc)

Designated facility	Proposed BSER	Proposed presumptive standards for GHGs
Super-Emitters	Root cause analysis and corrective action following notification of super-emitter emissions event.	Root cause analysis and corrective action following notification by an EPA-approved entity or regulatory authority of a super-emitter emissions event. ⁹
Fugitive Emissions: Single Wellhead Only Well Sites and Small Well Sites.	Quarterly AVO inspections	Quarterly AVO inspections. Repair for indications of potential leaks within 15 days of inspection. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Multi-wellhead Only Well Sites (2 or more wellheads).	Quarterly AVO inspections AND Monitoring and repair based on semiannual monitoring using OGI ² .	Quarterly AVO inspections. Repair for indications of potential leaks within 15 days of inspection. Semiannual OGI monitoring (Optional semiannual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Well Sites and Centralized Production Facilities.	Bimonthly AVO monitoring (<i>i.e.</i> , every other month). AND Well sites with specified major production and processing equipment: Monitoring and repair based on quarterly monitoring using OGI.	Bimonthly AVO inspections. Repair for indications of potential leaks within 15 days of inspection. AND Well sites with specified major production and processing equipment: Quarterly OGI monitoring. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Compressor Stations	Monthly AVO monitoring AND Monitoring and repair based on quarterly monitoring using OGI.	Monthly AVO monitoring. AND Quarterly OGI monitoring. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations on Alaska North Slope.	Monitoring and repair based on annual monitoring using OGI.	Annual OGI monitoring. (Optional annual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations.	(Optional) Screening, monitoring, and repair based on periodic screening using an advanced measurement technology instead of OGI monitoring.	(Optional) Alternative periodic screening with advanced measurement technology instead of OGI monitoring.
Fugitive Emissions: Well Sites and Compressor Stations.	(Optional) Monitoring and repair based on using a continuous monitoring system instead of OGI monitoring.	(Optional) Alternative continuous monitoring system instead of OGI monitoring.
Storage Vessels: Tank Battery with PTE of 20 tpy or More of Methane.	Capture and route to a control device	95 percent reduction of methane.
Pneumatic Controllers: Natural gas-driven that Vent to the Atmosphere.	Use of zero-emissions controllers	Methane emission rate of zero.

TABLE 3—SUMMARY OF PROPOSED BSER AND PROPOSED PRESUMPTIVE STANDARDS FOR GHGS FROM DESIGNATED FACILITIES (EG OOOOc)—Continued

Designated facility	Proposed BSER	Proposed presumptive standards for GHGs
Pneumatic Controllers: Alaska (at sites where onsite power is not available—continuous bleed natural gas-driven).	Use of low-bleed pneumatic controllers	Natural gas bleed rate no greater than 6 scfh.
Pneumatic Controllers: Alaska (at sites where onsite power is not available—intermittent natural gas-driven).	Monitor and repair through fugitive emissions program.	OGI monitoring and repair of emissions from controller malfunctions.
Gas Well Liquids Unloading	Employ techniques or technologies that eliminate methane emissions. If this is not feasible for safety or technical reasons, employ best management practices to minimize venting of emissions to the maximum extent possible.	Perform liquids unloading with zero methane emissions. If this is not feasible for safety or technical reasons, employ best management practices to minimize venting of emissions to the maximum extent possible.
Wet Seal Centrifugal Compressors (except for those located at well sites).	Conduct preventative maintenance and repair to maintain flow rate at or below 3 scfm ⁷ .	Volumetric flow rate of 3 scfm.
Dry Seal Centrifugal Compressors (except for those located at well sites).	Conduct preventative maintenance and repair to maintain flow rate at or below 3 scfm ⁷ .	Volumetric flow rate of 3 scfm.
Reciprocating Compressors (except for those located at well sites).	Repair or replace the reciprocating compressor rod packing in order to maintain a flow rate at or below 2 scfm.	Volumetric flow rate of 2 scfm.
Pneumatic Pumps	Use of zero-emission pumps that are not powered by natural gas.	Methane emission rate of zero.
Equipment Leaks at Natural Gas Processing Plants.	LDAR with bimonthly OGI	LDAR with OGI following procedures in appendix K.
Oil Wells with Associated Gas	Route associated gas to a sales line. If access to a sales line is not available, the gas can be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent reduction in methane emissions.	Route associated gas to a sales line. If access to a sales line is not available, the gas can be used as an onsite fuel source or used for another useful purpose that a purchased fuel or raw material would serve. If demonstrated that a sales line and beneficial uses are not technically feasible, the gas can be routed to a flare or other control device that achieves at least 95 percent reduction in methane emissions.

C. Costs and Benefits

In accordance with the requirements of Executive Order (E.O.) 12866, the EPA projected the emissions reductions, costs, and benefits that may result from this proposed action if finalized as proposed. These results are presented in detail in the RIA accompanying this proposal developed in response to E.O. 12866. The RIA focuses on the elements of the proposed rule that are likely to result in quantifiable cost or emissions changes compared to a baseline that incorporates changes to the regulatory requirements induced by the Congressional Review Act (CRA) resolution¹⁰ but does not incorporate

⁹ As described in section IV.C, the EPA is proposing a super-emitter response program under the statutory rationale that super-emitters are a designated facility. The EPA is also proposing the program under a second rationale that the super-emitter response program constitutes work practice standards for certain sources and compliance assurance measures for other sources. Under either rationale, state plans are generally required to adopt the super-emitter response program either as presumptive standards or as measures that provide for the implementation and enforcement of such standards.

¹⁰ See November 2021 Proposal, 86 FR at 63116 (discussing the CRA Resolution and its effect on regulatory requirements).

the proposed standards. We estimated the cost, emissions, and benefit impacts for the 2023 to 2035 period. We present the present value (PV) and equivalent annual value (EAV) of costs, benefits, and net benefits of this action in 2019 dollars.

The initial analysis year in the RIA is 2023 as we assume the proposed rule will be finalized early in 2023. The NSPS will take effect immediately and impact sources constructed after publication of the proposed rule. The EG will take longer to go into effect as states will need to develop implementation plans in response to the rule and have them approved by the EPA. We assume in the RIA that this process will take 3 years, and so EG impacts will begin in 2026. The final analysis year is 2035, which allows us to provide 10 years of projected impacts after the EG is assumed to take effect.

The cost analysis presented in the RIA reflects a nationwide engineering analysis of compliance cost and emissions reductions, of which there are two main components. The first component is a set of representative or model plants for each regulated facility, segment, and control option. The

characteristics of the model plant include typical equipment, operating characteristics, and representative factors including baseline emissions and the costs, emissions reductions, and product recovery resulting from each control option. The second component is a set of projections of activity data for affected facilities, distinguished by vintage, year, and other necessary attributes (e.g., oil versus natural gas wells). Impacts are calculated by setting parameters on how and when affected facilities are assumed to respond to a particular regulatory regime, multiplying activity data by model plant cost and emissions estimates, differencing from the baseline scenario, and then summing to the desired level of aggregation. In addition to emissions reductions, some control options result in natural gas recovery, which can then be combusted in production or sold. Where applicable, we present projected compliance costs with and without the projected revenues from product recovery.

The EPA expects climate and health benefits due to the emissions reductions projected under this proposed rule. The EPA estimated the climate benefits of

methane (CH₄) emission reductions expected from this proposed rule using the social cost of methane (SC-CH₄) estimates presented in the “Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under E.O. 13990” (IWG 2021) published in February 2021 by the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG). As a member of the IWG involved in the development of the February 2021 TSD, the EPA agrees that these estimates continue to represent at this time the most appropriate estimate of the SC-CH₄ until revised estimates have been developed reflecting the latest, peer-reviewed science. However, as discussed in Section VII.E, the EPA also presents a sensitivity analysis of the monetized climate benefits using a set of SC-CH₄ estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017). The EPA notes that the benefits analysis is entirely distinct from the statutory BSER determinations proposed herein and is presented solely for the purposes of complying with E.O. 12866.

Under the proposed rule, the EPA expects that VOC emission reductions will improve air quality and are likely to improve health and welfare

associated with exposure to ozone, particulate matter with a diameter of 2.5 micrometers or less (PM_{2.5}), and hazardous air pollutants (HAP). Calculating ozone impacts from VOC emissions changes requires information about the spatial patterns in those emissions changes. In addition, the ozone health effects from the proposed rule will depend on the relative proximity of expected VOC and ozone changes to population. In this analysis, we have not characterized VOC emissions changes at a finer spatial resolution than the national total. In light of these uncertainties, we present an illustrative screening analysis in appendix C of the RIA based on modeled oil and natural gas VOC contributions to ozone concentrations as they occurred in 2017 and do not include the results of this analysis in the estimate of benefits and net benefits projected from this proposal.

The projected national-level emissions reductions over the 2023 to 2035 period anticipated under the proposed requirements are presented in Table 4. Table 5 presents the PV and EAV of the projected benefits, costs, and net benefits over the 2023 to 2035 period under the proposed requirements using discount rates of 3 and 7 percent. The estimates presented in Tables 4 and 5 reflect an updated analysis compared

with the RIA that accompanied the November 2021 proposal. The updated analysis not only incorporates the new provisions put forth in the supplemental proposal (in addition to the elements of the November 2021 proposal that are unchanged), but also includes key updates to assumptions and methodologies that impact both the baseline and policy scenarios. As such, the estimates presented in the tables are not directly comparable to corresponding estimates presented in the November 2021 proposal. Additionally, we note that the estimated emission reductions in both proposals may not fully characterize the emissions reductions achieved by this rule because they might not fully account for the emissions resulting from super-emitter emissions events that would be prevented or quickly corrected as a result of this rule.

The EPA solicits comments on any relevant data, appropriate methodologies, or reliable estimates to help quantify the costs, emissions reductions, benefits, and potential distributional effects related to super-emitter events, the proposed emissions control requirements for associated gas from oil wells, and the proposed storage vessel control requirements at centralized production facilities and in the gathering and boosting segment.

TABLE 4—PROJECTED EMISSIONS REDUCTIONS UNDER THE PROPOSED RULE, 2023–2035 TOTAL

Pollutant	Emissions reductions (2023–2035 total)
Methane (million short tons) ^a	36
VOC (million short tons)	9.7
Hazardous Air Pollutant (million short tons)	0.39
Methane (million metric tons CO ₂ Eq.) ^b	810

^a To convert from short tons to metric tons, multiply the short tons by 0.907. Alternatively, to convert metric tons to short tons, multiply metric tons by 1.102.

^b Carbon dioxide equivalent (CO₂ Eq.) calculated using a global warming potential of 25.

TABLE 5—BENEFITS, COSTS, NET BENEFITS, AND EMISSIONS REDUCTIONS OF THE PROPOSED RULE, 2023 THROUGH 2035

[Dollar estimates in millions of 2019 dollars]^a

	Present value	Equivalent annual value	Present value	Equivalent annual value
	3 Percent Discount Rate			
Climate Benefits ^b	\$48,000	\$4,500	\$48,000	\$4,500
	3 Percent Discount Rate		7 Percent Discount Rate	
Net Compliance Costs	\$14,000	\$1,400	\$12,000	\$1,400
Compliance Costs	19,000	1,800	15,000	1,800
Product Recovery	4,600	440	3,300	390
Net Benefits	34,000	3,200	36,000	3,100
Non-Monetized Benefits	Climate and ozone health benefits from reducing 36 million short tons of methane from 2023 to 2035. PM _{2.5} and ozone health benefits from reducing 9.7 million short tons of VOC from 2023 to 2035. ^c HAP benefits from reducing 390 thousand short tons of HAP from 2023 to 2035.			

TABLE 5—BENEFITS, COSTS, NET BENEFITS, AND EMISSIONS REDUCTIONS OF THE PROPOSED RULE, 2023 THROUGH 2035—Continued

[Dollar estimates in millions of 2019 dollars]^a

	Present value	Equivalent annual value	Present value	Equivalent annual value
	Emissions reductions from the super-emitter response program. Visibility benefits. Reduced vegetation effects.			

^a Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

^b Climate benefits are based on reductions in methane emissions and are calculated using four different estimates of the SC-CH₄ (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average SC-CH₄ at a 3 percent discount rate, but the Agency does not have a single central SC-CH₄ point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CH₄ estimates; the present value (and equivalent annual value) of the additional benefit estimates ranges from \$19 billion to \$130 billion (\$2.1 billion to 12 billion) over 2023 to 2035 for the proposed option. Please see Table 3–5 and Table 3–8 of the RIA for the full range of SC-CH₄ estimates. As discussed in Section 3 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. Appendix B of the RIA presents the results of a sensitivity analysis using a set of SC-CH₄ estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017). All net benefits are calculated using climate benefits discounted at 3 percent.

^c A screening-level analysis of ozone benefits from VOC reductions can be found in appendix C of the RIA, which is included in the docket.

II. General Information

A. Does this action apply to me?

Categories and entities potentially affected by this action include:

TABLE 6—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS ACTION

Category	NAICS code ¹	Examples of regulated entities
Industry	211120 211130 221210 486110 486210	Crude Petroleum Extraction. Natural Gas Extraction. Natural Gas Distribution. Pipeline Distribution of Crude Oil. Pipeline Transportation of Natural Gas.
Federal Government	Not affected.
State/local/tribal government	Not affected.

¹ North American Industry Classification System (NAICS).

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. Other types of entities not listed in the table could also be affected by this action. To determine whether your entity is affected by this action, you should carefully examine the applicability criteria found in the final rule. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section, your air permitting authority, or your EPA Regional representative listed in 40 CFR 60.4 (General Provisions).

B. How do I obtain a copy of this document, background information, and other related information?

In addition to being available in the docket, an electronic copy of the proposed action is available on the internet. Following signature by the Administrator, the EPA will post a copy of this proposed action at <https://www.epa.gov/controlling-air-pollution->

oil-and-natural-gas-industry. Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the supplemental proposal and key technical documents at this same website and at Docket ID No. EPA-HQ-OAR-2021-0317 located at <https://www.regulations.gov/>.

III. Purpose of This Regulatory Action

A. What is the purpose of this supplemental proposal?

On November 15, 2021, the EPA published a proposed rulemaking that included proposed NSPS and EGs to mitigate climate-destabilizing pollution and to protect human health by reducing GHG and VOC emissions from the Oil and Natural Gas Industry, specifically the Crude Oil and Natural Gas source category. The November 2021 proposal included comprehensive analyses of the available data for methane and VOC emissions sources in the Crude Oil and Natural Gas source category and the latest available information on control measures and

techniques to identify achievable, cost-effective measures to significantly reduce emissions, consistent with the requirements of section 111 of the CAA. The November 2021 proposal also solicited comment and information on specific topics.

New information was received and reviewed that was not considered in the November 2021 proposal. As a result, changes to some of the standards and other provisions proposed in November 2021 are being proposed in this supplemental notice.

Some of the new information was provided by commenters during the November 2021 proposal public comment period. Approximately 470,000 public comment letters were submitted on the November 2021 proposal representing a wide range of stakeholders and state and tribal governments. The EPA reviewed and considered the comments received, including the responses to the specific solicitations for information and input in the development of this supplemental proposal. Several of the commenters

representing diverse stakeholder perspectives expressed general support for the proposal and requested that the EPA further strengthen the proposed standards and make them more comprehensive. Other commenters highlighted implementation or cost concerns related to some of the elements proposed in the November 2021 proposal. Some commenters also provided data and information that the EPA was able to use to refine or revise several of the standards included in the November 2021 proposal.

This supplemental proposal only addresses specific comments that the EPA determined warranted changes to what was proposed. It does not address/summarize all of the comments submitted on the November 2021 proposal. The EPA will continue to evaluate all the previously submitted comments, as well as new comments submitted on this supplemental action, in the development of a final NSPS OOOOb and EG OOOOc. All relevant comments submitted on both proposals will be responded to at that time.

In summary, the purpose of this supplemental proposed rulemaking is to update, strengthen, and expand the standards proposed in the November 2021 proposal under CAA section 111(b) for methane and VOC emissions from new, modified, and reconstructed facilities, and the presumptive standards proposed under CAA section 111(d) for methane emissions from existing sources. In addition, this proposal: (1) Proposes to reduce emissions from the source category more comprehensively by adding proposed standards for certain sources that were not addressed in the November 2021 proposal, revising the proposed requirements for fugitive emissions monitoring and repair, and by establishing a super-emitter response program to target timely mitigation of super-emitter emissions events; (2) encourages the deployment of innovative technologies and techniques for detecting and reducing methane emissions by providing additional options for the use of advanced monitoring; (3) modifies and refines certain aspects of the proposed standards in response to concerns and information submitted in public comments; and (4) provides additional information not included in the November 2021 proposal for public comment, such as content for the new subparts that reflects the proposed standards and emission guidelines, and details of the timelines and other implementation requirements that apply to states to limit methane pollution from existing designated facilities in the

source category under CAA section 111(d).

This supplemental notice also includes an updated RIA that accounts for the full impacts of these proposed actions. If finalized and implemented, the proposed actions in this rulemaking, as detailed in the November 2021 proposal and this supplemental proposal, would result in significant and cost-effective reductions in climate and health-harming pollution while encouraging the continued development and deployment of innovative technologies to further reduce this pollution in the Crude Oil and Natural Gas source category.

The summary and rationale for changes to the November 2021 proposed NSPS OOOOb and EG OOOOc standards are presented in section IV of this preamble. For each change, a high-level summary of the relevant points raised by commenters leading to the change is provided, followed by the EPA's rationale for the change. In addition to changes from the November 2021 proposal that are the result of public comments, the EPA has also included changes made as a result of additional EPA review and consideration of available information.

Section V of this preamble proposes specific requirements for the implementation of the proposed EG to provide states with information needed for purposes of EG state plan development. First, we discuss changes to the proposed requirements for establishing standards of performance in state plans. Second, we discuss changes to the proposed components of an approvable state plan submission. Third, we discuss the proposed timing for state plan submissions, and changes to the proposed timeline for designated facilities to come into final compliance with the state plan.

Section VI of this preamble includes requirements for using optical gas imaging in leak detection as appendix K to 40 CFR part 60 (appendix K). It provides an overview of the November 2021 proposal, significant changes made to the proposal and the basis for those changes, and a summary of the updated appendix K requirements.

Section VII of this supplemental proposal includes updates to the impacts of the November 2021 NSPS proposal based on changes discussed in sections IV and V of this preamble.

The EPA is requesting comments on all aspects of the supplemental proposal to enable the EPA to develop a final rule that, consistent with our responsibilities under section 111 of the CAA, achieves the greatest possible reductions in methane and VOC emissions while

remaining achievable, cost effective, and conducive to technological innovation. Because this preamble includes comment solicitations/requests on several topics and issues, we have prepared a separate memorandum that presents these comment requests by section and topic as a guide to assist commenters in preparing comments. This memorandum and supporting materials can be obtained from the Docket for this action (see Docket ID No. EPA-HQ-OAR-2021-0317). The title of the memorandum is "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review—Supplemental Proposed Rule Summary of Comment Solicitations."

B. What date defines a new, modified, or reconstructed source for purposes of the proposed NSPS OOOOb?

For the reasons explained below, NSPS OOOOb would apply to all emissions sources ("affected facilities") identified in the proposed 40 CFR 60.5365b, except dry seal centrifugal compressors, that commenced construction, reconstruction, or modification after November 15, 2021. NSPS OOOOb would apply to dry seal centrifugal compressor affected facilities that commence construction, reconstruction, or modification after December 6, 2022.

Pursuant to CAA section 111(b), the EPA proposed new source performance standards (NSPS) for a wide range of emissions sources in the Crude Oil and Natural Gas source category (to be codified in 40 CFR part 60 subpart OOOOb) in a **Federal Register** notice published November 15, 2021. Some of the proposed standards resulted from the EPA's review of the current NSPS codified at 40 CFR part 60 subpart OOOOa (NSPS OOOOa), while others were proposed standards for additional emissions sources that are currently unregulated. The emissions sources for which the EPA proposed standards in the November 2021 proposal are as follows:

- Well completions
- Gas well liquids unloading operations
- Associated gas from oil wells
- Wet seal centrifugal compressors
- Reciprocating compressors
- Pneumatic controllers
- Pneumatic pumps
- Storage vessels
- Collection of fugitive emissions components at well sites, centralized production facilities, and compressor stations
- Equipment leaks at natural gas processing plants

- Sweetening units

These standards of performance would apply to “new sources.” CAA section 111(a)(2) defines a “new source” as “any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.” Because the proposed regulation proposing the standards for these emission sources was published November 15, 2021, “new sources” to which these standards apply are those that commenced construction, reconstruction, or modification after November 15, 2021.

We received comments on the November 2021 proposal that it lacks regulatory text and therefore should not be used to define new sources for purposes of NSPS OOOOb.¹¹ The EPA disagrees for the following reasons. CAA section 307(d)(3) specifies the information that a proposed rule under the CAA must contain, such as a statement of basis, supporting data, and major legal and policy considerations; the list of required information does not include proposed regulatory text. Similarly, the Administrative Procedures Act (APA), which governs most Federal rulemaking, does not require publication of the proposed regulatory text in the **Federal Register**. Section 553(b)(3) of the APA provides that a notice of proposed rulemaking shall include “*either* the terms or substance of the proposed rule *or* a description of the subjects and issues involved.” (Emphasis added). Thus, the APA clearly provides flexibility to describe the “subjects and issues involved” as an alternative to inclusion of the “terms or substance” of the proposed rule. See also *Rybachek v. EPA*, 904 F.2d 1276, 1287 (9th Cir. 1990) (the EPA’s “failure to propose in advance the actual wording” of a regulation does not make the regulation invalid where the “proposal . . . clearly describe[s] ‘the subjects and issues’” involved). The EPA solicits comments on whether CAA section 111(a) provides the EPA discretion to define “new sources” based on the publication date of a supplemental proposal and, if so, whether there are any unique circumstances here that would warrant

the exercise of such discretion in this rulemaking by the EPA.

In addition to the proposed standards, this supplemental proposal includes proposed standards for an additional emissions source, specifically dry seal centrifugal compressors. Because the EPA is proposing standards for dry seal centrifugal compressors for the first time in this supplemental proposal, “new sources” to which these standards apply are dry seal centrifugal compressors that commence construction, reconstruction, or modification after the date this supplemental proposal is published, which is December 6, 2022.

C. What date defines an existing source for purposes of the proposed EG OOOOc?

The November 2021 proposal also included proposed emissions guidelines for states to follow and develop plans to regulate existing sources in the Crude Oil and Natural Gas source category under EG OOOOc. Under CAA section 111, a source is either new, *i.e.*, construction, reconstruction, or modification commenced after a proposed NSPS is published in the **Federal Register** (CAA section 111(a)(1)), or existing, *i.e.*, any source other than a new source (CAA section 111(a)(6)). Accordingly, any source that is not subject to the proposed NSPS OOOOb as described is an existing source subject to EG OOOOc. As explained, new sources, with the exception of dry seal centrifugal compressors, are those that commenced construction, reconstruction, or modification after November 15, 2021; therefore, existing sources are those that commenced construction, reconstruction, or modification on or before November 15, 2021. Similarly, because new dry seal centrifugal compressors are those that commenced construction, reconstruction, or modification after December 6, 2022, existing dry seal centrifugal compressors are those that commenced construction, reconstruction, or modification on or before December 6, 2022.

D. How will the proposed EG OOOOc impact sources already subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa?

Sources currently subject to 40 CFR part 60, subpart KKK (NSPS KKK), 40 CFR part 60 subpart OOOO (NSPS OOOO), or NSPS OOOOa would continue to comply with their respective standards until a state or Federal plan implementing EG OOOOc becomes effective. For most designated facilities, the EPA proposes to conclude that compliance with the implementing

state or Federal plan that is consistent with the presumptive standards in EG OOOOc would constitute compliance with the older NSPS because the presumptive standards proposed for EG OOOOc result in the same or greater emission reductions than the current standards in the older NSPS.

In this rulemaking, the EPA is proposing standards for dry seal centrifugal compressor and intermittent bleed pneumatic controllers for the first time in NSPS OOOOb and EG OOOOc. Because these designated facilities (*i.e.*, dry seal centrifugal compressors and intermittent bleed pneumatic controllers) are not subject to regulation under a previous NSPS, they only need to comply with the state or Federal plan implementing EG OOOOc. The EPA is proposing presumptive standards for fugitive emissions at compressor stations, pneumatic pumps at natural gas processing plants, and pneumatic controllers at natural gas processing plants that are all the same or greater stringency than NSPS KKK, NSPS OOOO, and NSPS OOOOa, as applicable. Therefore, compliance with the state or Federal plan implementing EG OOOOc would satisfy compliance with the respective NSPS regulation. Additionally, the proposed presumptive standards in EG OOOOc for pneumatic pumps (excluding processing) and natural gas processing plant equipment leaks are more stringent than the standards in NSPS OOOOa for pneumatic pumps and all three NSPS for natural gas processing plant equipment leaks, and therefore compliance with the state or Federal plan implementing EG OOOOc would satisfy compliance with the respective NSPS regulation.

For wet seal centrifugal compressors, two different standards are in place for the older NSPS. NSPS KKK is an equipment standard that provides several compliance options including: (1) Operating the compressor with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; (2) equipping the compressor with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system, or that is connected by a CVS to a control device that reduces VOC emissions by 95 percent or more; or (3) equipping the compressor with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere. NSPS KKK exempts compressors from these requirements if it is either equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device

¹¹ See Document ID Nos. EPA-HQ-OAR-2021-0317-0424, EPA-HQ-OAR-2021-0317-0539, EPA-HQ-OAR-2021-0317-0579, EPA-HQ-OAR-2021-0317-0598, EPA-HQ-OAR-2021-0317-0599, EPA-HQ-OAR-2021-0317-0815, and EPA-HQ-OAR-2021-0317-0929.

that reduces VOC emissions by 95 percent, or if it is designated for no detectable emissions. NSPS OOOO and NSPS OOOOa require 95 percent reduction of emissions from each centrifugal compressor wet seal fluid degassing system. NSPS OOOO and OOOOa also allow the alternative of routing the emissions to a process. The proposed presumptive standards under EG OOOOc would be a numerical emission limit of 3 scfm, as described in IV.G. of this preamble, and includes an alternative compliance option to reduce methane emissions by 95 percent by routing to a control or process. The proposed presumptive standard of 3 scfm is less stringent than the standards in NSPS OOOO and OOOOa, and therefore, compliance with a state or Federal plan implementing EG OOOOc using the 3 scfm presumptive standard would not satisfy compliance with NSPS OOOO and NSPS OOOOa for wet seal centrifugal compressor designated facilities. However, the EPA is not aware of any wet seal centrifugal compressors subject to NSPS OOOO or NSPS OOOOa and the EPA believes that centrifugal compressors installed since those rules went into effect (August 2011 and September 2015) are utilizing dry seals rather than wet seals. For wet seal centrifugal compressors currently subject to KKK (those designated as new sources between January 1984 and August 2011), compliance with NSPS KKK would allow for compliance with the state or Federal plan implementing EG OOOOc because the zero emissions limit would also achieve the 3 scfm limit proposed in EG OOOOc. For an owner or operator who uses the alternative compliance method proposed in EG OOOOc of routing to a control or process, achieving 95 percent emissions reductions can be accomplished using the same compressor requirements as required in NSPS OOOOa. Thus, compliance with a state or Federal plan implementing EG OOOOc using the 95 percent control alternative would satisfy compliance with NSPS OOOO and NSPS OOOOa for wet seal centrifugal compressor designated facilities.

The NSPS KKK standard is more stringent than the proposed 3 scfm presumptive standard in EG OOOOc for methane emissions. Accordingly, for centrifugal compressors, NSPS KKK would still apply to compressors at natural gas processing plants for which construction, reconstruction, or modification commenced after January 20, 1984, and on or before August 23, 2011.

There are two different standards for reciprocating compressors in the older

NSPS: (1) NSPS KKK requires the use of a seal system and includes a barrier fluid system that prevents leakage of VOC to the atmosphere for reciprocating compressors located at natural gas processing plants, and (2) NSPS OOOO and NSPS OOOOa require changing out the rod packing every 3 years or routing emissions to a control. The proposed presumptive standard for EG OOOOc is a volumetric flow rate of 2 scfm. The proposed BSER is to repair and/or replace the reciprocating compressor rod packing in order to maintain the flow rate at or below 2 scfm (based on annual monitoring and additional preventative or corrective measures) and includes an alternative compliance option to route emissions to a process, as described in IV.I. of this preamble.

The NSPS KKK standard is more stringent than the proposed 2 scfm presumptive standard in EG OOOOc for methane emissions. Accordingly, for reciprocating compressors subject to NSPS KKK, the NSPS KKK provisions would still apply to reciprocating compressors at natural gas processing plants for which construction, reconstruction, or modification commenced after January 20, 1984, and on or before August 23, 2011. For NSPS KKK, several provisions effectively exempt certain reciprocating compressors at natural gas processing plants from the seal system requirements, including: an exemption for reciprocating compressors in wet gas service, a requirement that reciprocating compressors must be in VOC service (*i.e.*, at least 10 percent by weight VOC in the process fluid in contact with the compressor) for standards to apply, and an exemption for reciprocating compressors designated with no detectable emissions. If a reciprocating compressor at a natural gas processing plant was constructed, reconstructed, or modified between January 20, 1984, and August 23, 2011, is exempt from the provisions of NSPS KKK due to one of these conditions, it would be subject to the requirements of the state or Federal plan implementing EG OOOOc.

As explained in section XII.E.1.d. of the November 2021 proposal¹² and section IV.I of this preamble, the EPA finds that the proposed EG OOOOc standard is more efficient at discovering and reducing any emissions that may develop than the set 3-year replacement interval from NSPS OOOO and NSPS OOOOa. Overall, the proposed presumptive standards would produce more rod packing replacements, thereby reducing more emissions compared to the 3-year interval. Therefore, the EPA

is proposing that compliance with the state or Federal plan implementing EG OOOOc will satisfy compliance with the respective NSPS OOOO and OOOOa regulations for reciprocating compressor designated facilities.

The affected facility for storage vessels is defined in the NSPS OOOO and NSPS OOOOa as a single storage vessel with the potential to emit greater than 6 tons of VOC per year and the standard that applies is 95 percent emissions reduction. Under the proposed EG OOOOc, the designated facility is a tank battery with the potential to emit greater than 20 tons of methane per year with the same 95 percent emission reduction standard, as discussed in IV.J. of this preamble. Affected facilities under NSPS OOOO or OOOOa that are part of a designated facility under the EG would be required to meet the 95 percent reduction standard, and therefore would satisfy their respective NSPS requirement to do the same. Affected facilities under NSPS OOOO or OOOOa that emit 6 tpy or more of VOCs but that do not meet the potential to emit 20 tons of methane per year definition would continue to comply with the 95-percent emissions reduction standard in their respective NSPS. Scenarios regarding further physical or operational changes in NSPS OOOOb that would reclassify sources from the older NSPS and/or EG OOOOc into NSPS OOOOb are discussed in section IV.J.1.b. of this preamble.

Similarly, pneumatic controller affected facilities not located at natural gas processing plants are defined as single high-bleed controllers with a low-bleed standard under NSPS OOOO and NSPS OOOOa, while the designated facility under EG OOOOc is defined as a collection of natural gas-driven pneumatic controllers at a site with a zero emissions standard (discussed further in Section IV.D. of this preamble). The proposed zero-emissions presumptive standard in EG OOOOc is more stringent than the low-bleed standard found in the older NSPS, therefore the EPA is proposing that compliance with the state or Federal plan implementing EG OOOOc would satisfy compliance with the respective NSPS regulation for pneumatic controllers not located at a natural gas processing plant.

Lastly, standards for fugitive emissions from well sites under NSPS OOOOa require semiannual OGI monitoring on all components at the well site except for wellhead only well sites (which are not affected facilities), while the presumptive standards under the proposed EG OOOOc would require quarterly OGI monitoring at well sites

¹² 86 FR 63215 to 63220 (November 15, 2021).

with major production and processing equipment, semiannual OGI combined with quarterly AVO inspections at multi-wellhead only well sites,¹³ and quarterly AVO inspections for small sites and single wellhead well sites, as described in section IV.A of this preamble. It is clear that the proposed presumptive standards for well sites with major production and processing equipment and the proposed presumptive standards for multi-wellheads only well sites are both more stringent than the semiannual OGI monitoring standard under NSPS OOOOa because one would require more frequent OGI monitoring while the other would require AVO inspections in addition to semiannual OGI monitoring; therefore, for these existing wellsites that are also subject to NSPS OOOOa, compliance with proposed presumptive standards would be deemed in compliance with the semiannual OGI monitoring standard in NSPS OOOOa. With respect to existing single wellhead only well sites and small sites that are also subject to the semiannual monitoring under NSPS OOOOa, the EPA is proposing that compliance with the proposed presumptive standards, specifically quarterly AVO, would satisfy NSPS OOOOa for the following reasons. First, as explained in more detail in section IV.A, AVO is effective, and therefore OGI is unnecessary, for detecting fugitive emissions from many of the fugitive emissions components at these sites. Second, by requiring more frequent visits to the sites, the proposed presumptive standard would allow earlier detection and repair of fugitive emissions, in particular large emissions from components such as thief hatches on uncontrolled storage vessels. In light of the above, the EPA finds that the presumptive standards under the proposed EG OOOOc would effectively address the fugitive emissions at these well sites, and that semiannual OGI monitoring would no longer be necessary for these well sites that are also subject to NSPS OOOOa. For the reasons stated above, the EPA is proposing to conclude that compliance with the state or Federal plan implementing the presumptive fugitive emissions standards in the proposed EG OOOOc may be deemed to satisfy compliance with monitoring standards (*i.e.*, semiannual monitoring using OGI) in NSPS OOOOa for all well sites.

¹³ Because of a difference in the definition of a wellhead only well site in NSPS OOOOa and the proposed EG OOOOc, some single and multi-wellhead only well sites could be subject to the semiannual OGI monitoring under NSPS OOOOa.

The EPA is soliciting comment on all aspects of the proposed comparison of standards in the older NSPS to the proposed presumptive standards in EG OOOOc. Specifically, the EPA is requesting comment relevant to the comparison of stringency for compressors (both centrifugal and reciprocating) to NSPS KKK and for fugitive emissions monitoring at small well sites.

E. How does the EPA consider costs in this supplemental proposal?

In the November 2021 proposal, the EPA described the various approaches for evaluating control costs in its BSER analyses. 86 FR 63154–63157 (November 15, 2021). As described in that document, in considering the costs of the control options evaluated in this action, the EPA estimated the control costs under various approaches, including annual average cost-effectiveness and incremental cost-effectiveness of a given control. In its cost-effectiveness analyses, the EPA recognized and took into account that these multi-pollutant controls reduce both VOC and methane emissions in equal proportions, as reflected in the single-pollutant and multipollutant cost effectiveness approaches for the proposed NSPS OOOOb. The EPA also considered cost saving from the natural gas recovered instead of vented due to the proposed controls. In both the November 2021 proposal¹⁴ and this supplemental proposal,¹⁵ the EPA proposes to find that cost-effectiveness values up to \$5,540/ton of VOC reduction are reasonable for controls that we have identified as BSER and within the range of what the EPA has historically considered to represent cost effective controls for the reduction of VOC emissions. Similarly, for methane, the EPA finds the cost-effectiveness values up to \$1,970/ton of methane reduction to be reasonable for controls that we have identified as BSER in both the November 2021 proposal and this supplemental proposal, well below the \$2,185/ton¹⁶ of methane reduction that EPA has previously found to be reasonable for the industry.

For this supplemental proposal, we also updated the two additional analyses that the EPA performed for the

November 2021 proposal to further inform our determination of whether the cost of control of the collection of proposed standards would be reasonable, similar to compliance cost analyses we have completed for other NSPS.¹⁷ The two additional analyses include: (1) A comparison of the capital costs incurred by compliance with the proposed rules to the industry's estimated new annual capital expenditures, and (2) a comparison of the annualized costs that would be incurred by compliance with the proposed standards to the industry's estimated annual revenues. In this section, the EPA provides updated information regarding these cost analyses based on the proposed standards described in this notice. See 86 FR 63156 (November 15, 2021) for additional discussion on these two analyses.

First, for the capital expenditures analysis, the EPA divided the nationwide capital expenditures projected to be spent to comply with the proposed standards by an estimate of the total sector-level new capital expenditures for a representative year to determine the percentage that the nationwide capital cost requirements under the proposal represent of the total capital expenditures by the sector. We combine the compliance-related capital costs under the proposed standards for the NSPS and for the presumptive standards in the proposed EG to analyze the potential aggregate impact of the proposal. The EAV of the projected compliance-related capital expenditures over the 2023 to 2035 period is projected to be about \$1.4 billion in 2019 dollars. We obtained new capital expenditure data for relevant NAICS codes for 2019 from the U.S. Census 2020 Annual Capital Expenditures Survey.¹⁸ While Census data on capital expenditures are available for 2020, these figures were heavily influenced by COVID-19-related impacts such that 2020 does is not an appropriate representative year to use in this analysis. According to these data, new capital expenditures for the sector in 2019 were about \$156 billion in 2019

¹⁷ For example, see our compliance cost analysis in “Regulatory Impact Analysis (RIA) for Residential Wood Heaters NSPS Revision. Final Report.” U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. EPA-452/R-15-001, February 2015.

¹⁸ U.S. Census Bureau, 2020 Annual Capital Expenditures Survey, Table 4b. Capital Expenditures for Structures and Equipment for Companies with Employees by Industry: 2019 Revised, <https://www.census.gov/data/tables/2020/econ/aces/2020-aces-summary.html>, accessed 7/12/2022.

¹⁴ 86 FR 63155 (November 15, 2021).

¹⁵ See November 2021 TSD at Document ID No. EPA-HQ-OAR-2021-0317-0166 and Supplemental TSD for this action located at Docket ID No. EPA-HQ-OAR-2021-0317.

¹⁶ 80 FR 56627 (June 6, 2016). See also, “Background Technical Support Document for the New Source Performance Standards 40 CFR part 60 subpart OOOOa (May 2016)”, at page 93, Table 6-7 located at Document ID No. EPA-HQ-OAR-2010-0505-7631.

dollars.¹⁹ Note that new capital expenditures for pipeline transportation of natural gas (NAICS 4862) includes only expenditures on structures as data on expenditures on equipment data are withheld to avoid disclosing data for individual enterprises. As a result, the capital expenditures used here represent an underestimate of the sector's expenditures. Comparing the EAV of the projected compliance-related capital expenditures under the proposal with the 2019 total sector-level new capital expenditures yields a percentage of about 0.9 percent, which is well below the percentage increase previously upheld by the courts.

Second, for the comparison of compliance costs to revenues, we use the EAV of the projected compliance costs without and with projected revenues from product recovery under the proposal for the 2023 to 2035 period then divided the nationwide annualized costs by the annual revenues for the appropriate NAICS code(s) for a representative year to determine the percentage that the nationwide annualized costs represent of annual revenues. Like we do for capital expenditures, we combine the costs projected to be expended to comply with the standards for NSPS and the presumptive standards in the proposed EG to analyze the potential aggregate impact of the proposal. The EAV of the associated increase in compliance cost over the 2023 to 2035 period is projected to be about \$1.7 billion without revenues from product recovery and about \$1.2 billion with revenues from product recovery (in 2019 dollars). Revenue data for relevant NAICS codes were obtained from the U.S. Census 2017 County Business Patterns and Economic Census, the most recent revenue figures available.²⁰ According to these data, 2017 receipts for the sector were about \$358 billion in 2019 dollars. Comparing the EAV of the projected compliance costs under the proposal with the sector-level receipts figure yields a percentage of about 0.5 percent without revenues from product recovery and about 0.4 percent with revenues from product recovery. More data and analysis supporting the comparison of capital expenditures and

annualized costs projected to be incurred under the rule and the sector-level capital expenditures and receipts is presented in the TSD for this action, which is in the public docket.

In considering the costs of the control options evaluated in this action, the EPA estimated the control costs under various approaches, including annual average cost-effectiveness and incremental cost-effectiveness of a given control. In its cost-effectiveness analyses, the EPA recognized and took into account that these multi-pollutant controls reduce both VOC and methane emissions in equal proportions, as reflected in the single-pollutant and multipollutant cost effectiveness approaches for the proposed NSPS OOOOb. The EPA also considered cost saving from the natural gas recovered instead of vented due to the proposed controls. Based on all of the considerations described, the EPA concludes that the costs of the controls that serve as the basis of the standards proposed in this action are reasonable. The EPA solicits comment on its approaches for considering control costs, as well as the resulting analyses and conclusions.

F. Legal Basis for Rulemaking Scope

In the November 2021 proposal, the EPA described the regulatory history of its authority to regulate methane emissions from the oil and gas source category under CAA section 111. The EPA explained that the 2016 Rule, 81 FR 35823 (June 3, 2016), established the agency's authority to regulate these methane emissions; the 2020 Policy Rule, 85 FR 57018 (September 14, 2020) had rescinded certain parts of the 2016 Rule, including its authorization to regulate methane; and a joint resolution under the Congressional Review Act (CRA), signed into law by President Biden on June 30, 2021, had rescinded the 2020 Policy Rule, and thereby reinstated the 2016 Rule's authorization to regulate methane. 86 FR 63135–36 (November 15, 2021).

In describing this history, the EPA noted that in the 2016 Rule, in response to comments, the EPA had explained that once it had listed a source category for regulation under section 111(b)(1)(A), it was not required to make, as a predicate to regulating GHG emissions from the source category, an additional pollutant-specific finding that those GHG emissions contribute significantly to dangerous air pollution (termed, a pollutant-specific significant contribution finding). However, in the alternative, the 2016 Rule did make such a finding, relying on information concerning the large amounts of

methane emissions from the source category. 86 FR 63135 (November 15, 2021) (citing 81 FR 35843; June 3, 2016). The November 2021 proposal further noted that in the legislative history of the CRA resolution, Congress made clear its intent that section 111 did not require or authorize a pollutant-specific significant contribution finding, and the EPA confirmed that it agreed with that interpretation. 86 FR 63148 (November 15, 2021).

Some commenters on the November 2021 proposal reiterated the argument that the EPA is required to make a pollutant-specific significant contribution finding for GHG emissions from the oil and gas source category and stated that in order to make such a finding, the EPA must identify a standard or criteria for when a contribution is significant.²¹ We may respond further to these comments in the final rule, but the November 2021 proposal notes that the legislative history of the CRA joint resolution rejected the position that a standard or criteria is necessary for determining significance, and explained, "It is fully appropriate for EPA to exercise its discretion to employ a facts-and-circumstances approach, particularly in light of the wide range of source categories and the air pollutants they emit that EPA must regulate under section 111." 86 FR 63151 (November 15, 2021) (quoting House Report at 11). That continues to be the EPA's view and is consistent with decades of practice under section 111. The EPA has listed dozens of source categories, beginning in 1971,²² in many cases on the basis of multiple pollutants emitted by the particular source category,²³ and has never identified a standard or criteria for determining significance.

If the EPA were required to develop a standard or criteria to determine significance, any reasonable set of criteria would necessarily focus on the amount of emissions from the source category and the harmfulness of the pollutant emitted. In the case of the oil and gas source category, the "massive quantities of methane emissions"

²¹ Comments of Permian Basin Petroleum Ass'n, Document ID No. EPA-HQ-OAR-2021-0317-0793 at 3–4 (citing 85 FR 57018, 57038 (September 14, 2020)).

²² List of Categories of Stationary Sources, 36 FR 5931 (March 31, 1971); see 40 CFR part 60.

²³ For example, when it listed "stationary gas turbines" as a source category, EPA considered emissions of particulates, nitrogen oxides, sulfur dioxide, carbon monoxide, and hydrocarbons. Addition to the List of Categories of Stationary Sources, 42 FR 53657 (October 3, 1977); Standards of Performance for New Stationary Sources: Proposed rule, 42 FR 53782, 53783 (October 3, 1977).

¹⁹ The total capital expenditures for the same NAICS codes during COVID 19-impacted 2020 were about \$90 billion.

²⁰ 2017 County Business Patterns and Economic Census. The Number of Firms and Establishments, Employment, Annual Payroll, and Receipts by Industry and Enterprise Receipts Size: 2017, <https://www.census.gov/programs-surveys/susb/data/tables.2017.html>, accessed September 4, 2021. Note receipts data are available only for Economic Census years (years ending in 2 and 7) so 2017 data remains the most recent data available.

contributed by the sector to the levels of well-mixed GHG in the atmosphere, as described in the November 2021 proposal, 86 FR 63148 (November 15, 2021), coupled with the potency of methane (with a global warming potential (GWP) of almost 30 or more than 80, depending on the time period of the impacts, 86 FR 63130; November 15, 2021), demonstrate that the source category's GHG emissions would be significant under any rational criteria-based approach. More specifically, as the EPA stated in the November 2021 proposal, as illustrated by the domestic and global GHGs comparison data summarized in that notice, the collective GHG emissions from the Crude Oil and Natural Gas source category are significant, whether the comparison is domestic (where this sector is the largest source of methane emissions, accounting for 28 percent of U.S. methane and 3 percent of total U.S. emissions of all GHGs), global (where this sector, accounting for 0.4 percent of all global GHG emissions, emits more than the total national emissions of over 160 countries, and combined emissions of over 60 countries), or when both the domestic and global GHG emissions comparisons are viewed in combination. See 86 FR 63131 (November 15, 2021).

The large quantity of methane emitted by the oil and gas source category is brought into sharp relief by the fact that, as the November 2021 proposal further stated, no single GHG source category dominates on the global scale. While the Crude Oil and Natural Gas source category, like many (if not all) individual GHG source categories, could appear small in comparison to total emissions, in fact, it is a very important contributor in terms of both absolute emissions, and in comparison, to other source categories globally or within the U.S. See 86 FR 63131 (November 15, 2021).

Importantly, the oil and gas source category is the largest emitter of methane of any source category in the United States. 86 FR 63129 (November 15, 2021). As described in the November 2021 proposal, methane is a potent greenhouse gas; over a 100-year timeframe, it is nearly 30 times more powerful at trapping climate warming heat than CO₂, and over a 20-year timeframe, it is 83 times more powerful. Because methane is a powerful greenhouse gas and is emitted in large quantities, reductions in methane emissions provide a significant benefit in reducing near-term warming. Indeed, one third of the warming due to GHGs that we are experiencing today is due to human emissions of methane. See 86 FR 63129 (November 15, 2021).

The large amounts of methane emissions from the oil and gas source category in relation to other domestic and global sources of methane, coupled with the harmfulness of methane, should be considered more than sufficient to satisfy any criterion or standard for evaluating significant contribution. In particular, in the context of a problem like climate change that is caused by the collective contribution of many different sources, the fact that the oil and gas source category has the largest amount of methane emissions in the United States confirms that those emissions would meet a criterion or standard for significance.²⁴

G. Inflation Reduction Act

The Inflation Reduction Act (IRA) was signed into law on August 16, 2022. Section 60113 of the IRA amended the CAA by adding section 136, "Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems." Under this new section of the CAA, subsection 136(c), "Waste Emission Charge," requires the Administrator to "impose and collect a charge on methane emissions that exceed an applicable waste emissions threshold under subsection (f) from an owner or operator of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year pursuant to subpart W of part 98 of title 40, Code of Federal Regulations (40 CFR part 98), regardless of the reporting threshold under that subpart." An "applicable facility" is defined under CAA section 136(d) by reference to specific industry segments as defined in

²⁴ The EPA acknowledges that the collective nature of the climate change problem means it will likely also be appropriate to regulate other source categories of methane emissions that are not necessarily as large as the oil and gas source category, *cf. EPA v. EME Homer City*, 572 U.S. 489, 514 (2014) (affirming framework to address "the collective and interwoven contributions of multiple upwind States" to ozone nonattainment), as indicated by the fact that EPA has long regulated landfill gas, which consists of methane in 50 percent part. "Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills; Final Rule," 81 FR 59276, 59281 (August 29, 2016). But this does not mean that it would be appropriate to regulate *all* other types of sources, even ones with few emissions. In the past, the EPA has declined to regulate air pollutants emitted from source categories in quantities too small to be worrisome and because regulation would have produced little environmental benefit. See *Nat'l Lime Ass'n. v. EPA*, 627 F.2d 416, 426 & n.27 (D.C. Cir. 1980) (small amounts of emissions of nitrogen oxides and carbon monoxide from lime kilns was a key factor in EPA decision not to promulgate new source performance standards for those pollutants; citing Standards of Performance for New Stationary Sources Lime Manufacturing Plants—Proposed Rule, 42 FR 22506, 22507 (May 3, 1977)).

the Greenhouse Gas Reporting Program (GHGRP) petroleum and natural gas systems source category (40 CFR part 98, subpart W, also referred to as "GHGRP subpart W"). Pursuant to CAA section 136(g), the charge is to be imposed and collected beginning with respect to emissions reported for calendar year 2024 and for each year thereafter.

CAA section 136(f) identifies several circumstances under which the charges shall not be imposed on an owner or operator of an affected facility. In particular, CAA section 136(f)(6)(A) states that "charges shall not be imposed pursuant to subsection (c) on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111 upon a determination by the Administrator that:

(i) Methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 have been approved and are in effect in all States with respect to the applicable facilities; and

(ii) compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by the proposed rule of the Administrator entitled 'Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review' (86 FR 63110 (November 15, 2021)), if such rule had been finalized and implemented."

Per section 136(c)(6)(B) "if the conditions in clause (i) or (ii) of subparagraph (A) cease to apply after the Administrator has made the determination in that subparagraph, the applicable facility will again be subject to the charge under subsection (c) beginning in the first calendar year in which the conditions in either clause (i) or (ii) of that subparagraph are no longer met."

The EPA intends to take one or more separate actions in the future to implement the Methane Emissions and Waste Reduction Incentive Program, including revisions to certain requirements of GHGRP subpart W, and will provide an opportunity for public comment on the implementation of the Methane Emissions and Waste Reduction Incentive Program in those actions. Accordingly, the EPA considers the implementation of the Methane Emissions and Waste Reduction Incentive Program to be outside the scope of this supplemental proposed rule. However, the EPA is requesting comments on the criteria and approaches that the Administrator

should consider in making the CAA section 136(f)(6)(A)(ii) determination (“IRA equivalence determination”) because the EPA expects that the public and regulated industry will be interested in how the scope of the final oil and gas standards and emission guidelines may influence the applicability of the statutory exemption.

With respect to CAA section 136(f)(6)(A)(ii), the Administrator must determine that the methane emission standards in effect pursuant to CAA sections 111(b) and (d) “will result in equivalent or greater emissions reductions as would be achieved” by the EPA’s November 2021 proposed rule. As a general matter, the EPA believes that the changes being proposed in today’s action do not reduce expected methane emission reductions relative to the November 2021 proposal. Instead, the EPA anticipates that most, if not all, of the proposed changes contained in this supplemental proposal would likely lead to greater methane emissions reductions when fully implemented. For this reason, the Agency further anticipates that promulgation of Federal and state standards consistent with this supplemental proposal would result in methane emissions reductions at least as great as the November 2021 proposal. However, at this point, the EPA’s analysis is purely qualitative. The EPA does not believe that it is appropriate to quantitatively compare the emission reductions from the November 2021 proposal and this supplemental proposal because, as is discussed in section 1.3 of the RIA, the analysis of this supplemental proposal includes key updates to assumptions and methodologies that impact both the baseline and policy scenarios. As such, the estimated impacts presented in the RIA of this supplemental proposal are not directly comparable to corresponding estimates presented in the RIA of the November 2021 proposal.

Moreover, the statutory language in CAA section 136(f)(6)(A)(ii) does not indicate how the EPA should conduct this equivalency evaluation and what factors should influence how the EPA conducts the comparison. Because of this ambiguity in the statutory language, the EPA is requesting comments on how to best conduct this evaluation and on factors and assumptions the EPA should consider in conducting such an evaluation.

First, the EPA seeks comments on temporal elements of the evaluation. The EPA believes that the appropriate temporal comparison should be based on when requirements are fully implemented by the sources (*i.e.*, if a

state phases in installation of zero-emitting pneumatic controllers over more than one year, the comparison should be made at the point that the emission guidelines require full use of zero-emitting controllers). The EPA seeks comment on this approach versus an alternative such as making a multi-year comparison beginning with the effective date of the rule. In either case, as discussed below, such a determination could be made prospectively based either on the rule finalized by the EPA or when state plans have been approved. As discussed in section V.D. of the supplemental proposal, the EPA is proposing to require the submission of state plans under EG OOOOc within 18 months after publication of the final EG. In addition, the EPA is proposing to require that state plans impose a compliance timeline on designated facilities to require final compliance with the standards of performance as expeditiously as practicable, but no later than 36 months following the state plan submittal deadline.

Second, the EPA seeks comments on geographical elements of the evaluation. Per the statutory language in CAA section 136(f)(6)(A)(i), the EPA’s evaluation is to be done with respect to all states. The EPA requests comments on whether we should consider making a national evaluation of equivalency or whether we should consider a state-by-state evaluation instead. Under a national evaluation, the EPA envisions conducting an assessment of the reductions achieved across all states and then evaluating those reductions collectively against the collective reductions anticipated from implementation of the November 2021 proposal. Under a state-by-state evaluation, the EPA envisions needing to analyze whether every state is achieving equivalent or greater reductions than that state would have achieved under the November 2021 proposal.

Third, the EPA requests comments on whether the EPA should make the evaluation and the IRA equivalency determination in advance of states having submitted fully approvable plans or instead make the evaluation and IRA equivalency determination at a later date once the standards of performance pursuant to CAA section 111(b) and 111(d) are fully promulgated (*e.g.*, the EPA has approved state plans and/or developed a Federal Plan). In particular, the EPA request comments on whether the EPA’s analysis should compare the November 2021 EG proposal and final EG OOOOc by assuming designated facilities would be subject to their

corresponding EG presumptive standards once state plans are implemented, or whether we should compare the November 2021 EG proposal to the actual state plans that are approved. As to the latter approach, the EPA seeks comments on how a state’s invocation of RULOF to apply a less stringent standard to a designated facility might affect the equivalency evaluation and IRA equivalency determination. In establishing standards of performance for individual sources, CAA section 111(d) and the EPA’s regulations provide that states may invoke RULOF for the application of less stringent standards provided they meet the certain requirements established in the EPA’s regulations and the EG (see section V.B.3 below). As a result, it is possible that those state plans (individually or collectively) may not result in equivalent or greater emissions reductions as would be achieved by full implementation of the presumptive standards in the November 2021 proposal, unless the state plans require other sources to overperform to compensate for the less stringent RULOF standards or the EPA’s geographical evaluation is national in scope and national emissions result in equivalent or greater emissions reductions, even taking into account RULOF. The EPA requests comments on whether and how to account for the potential application of RULOF in state plans in the IRA equivalency determination and whether it would be appropriate to conduct any evaluation without considering the application of RULOF.

The EPA notes that nothing in the new CAA section 136 supersedes the EPA’s statutory obligations under CAA section 111. The Methane Emission and Waste Reduction Incentive Program does not supersede the EPA’s statutory obligation, under CAA section 111, to regulate methane emissions from the Crude Oil and Natural Gas source category. The EPA first regulated GHG emissions from new, reconstructed, and modified sources through limitations on methane emissions in its 2016 NSPS OOOOa rulemaking. Therefore, the Agency is obligated to review those standards at least every 8 years pursuant to CAA section 111(b)(1)(B). Moreover, CAA section 111(d) requires the EPA to establish emission guidelines to regulate methane emissions from any existing sources in the sector to which a standard of performance would apply if it were a new source. Although CAA section 136(f)(6) provides that facilities may be exempted from the obligation to pay methane charges if they are

compliant with applicable CAA section 111(b) and (d) standards meeting certain criteria after the Administrator makes the IRA equivalency determination in CAA section 136(f)(6)(A), CAA section 136 does not provide that the Methane Emission and Waste Reduction Incentive Program may, in the alternative, serve as a compliance alternative for any applicable CAA section 111 standards for methane. Accordingly, affected facilities subject to the final NSPS OOOOb must continue to comply with the final standards of performance regardless of whether they are subject to or exempted from the waste emissions charge. Likewise, designated facilities subject to standards of performance pursuant to either an approved state plan or a federal plan according to the requirements in CAA section 111(d) and the final EG OOOOc must continue to comply with those standards regardless of whether they are subject to or exempted from the waste emissions charge. The EPA acknowledges the potential interplay between the provisions in this proposed rule and the Methane Emissions and Waste Reduction Incentive Program and invites comment on approaches for examining the economic impacts of these programs individually and collectively.

IV. Summary and Rationale for Changes to the Proposed NSPS OOOOb and EG OOOOc

A. Fugitive Emissions From Well Sites, Centralized Production Facilities, and Compressor Stations

As discussed in section XI.A of the November 2021 proposal preamble (86 FR 63169; November 15, 2021), fugitive emissions are unintended emissions that can occur from a range of components at any time. The magnitude of these emissions can also vary widely. The EPA has historically addressed fugitive emissions from the Crude Oil and Natural Gas source category through ground-based component level monitoring using OGI or Method 21 of appendix A–7 to 40 CFR part 60 (EPA Method 21).

This section presents a summary of the November 2021 proposal, the rationales for making certain changes to the proposed standards and requirements, and the resulting NSPS standards and EG presumptive standards the EPA is proposing via this supplemental proposal for fugitive emissions from well sites and compressor stations. For proposed standards and requirements that have not changed since the November 2021

proposal, their supporting rationales are not reiterated in this supplemental proposal. Rationale included in the November 2021 proposal for these standards and requirements can be found in that proposal preamble (86 FR 63110; November 15, 2021) and in the technical support document (TSD) for the November 2021 proposal located at (EPA–HQ–OAR–2017–0166).

1. Fugitive Emissions at Well Sites and Centralized Production Facilities

a. NSPS OOOOb

i. Summary of November 2021 Proposal

Affected Facility. The November 2021 proposal defined the affected facility as the collection of fugitive emissions components located at well sites and centralized production facilities. The November 2021 proposal excluded “wellhead only well sites” as affected facilities under NSPS OOOOb, which were defined as well sites with one or more wellheads and no major production and processing equipment. Major production and processing equipment was defined as reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels.

Definition of fugitive emissions component. The November 2021 proposal included an expanded definition of fugitive emissions component that was intended to capture the known sources of large emission events. Specifically, the proposed definition in the November 2021 proposal defined a fugitive emissions component as “any component that has the potential to emit fugitive emissions of methane and VOC at a well site or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, all covers and CVS, all thief hatches or other openings on a controlled storage vessel, compressors, instruments, meters, natural gas-driven pneumatic controllers, or natural gas-driven pneumatic pumps. However, natural gas discharged from natural gas-driven pneumatic controllers or natural gas-driven pumps are not considered fugitive emissions if the device is operating properly and in accordance with manufacturers specifications. Control devices, including flares, with emissions resulting from the device operating in a manner that is not in full compliance with any Federal rule, state rule, or permit, are also considered fugitive emissions components.” (86 FR 63170; November 15, 2021).

Summary of November 2021 Proposal BSER Analysis. The methodology used to determine BSER for the November

2021 proposal was presented in the section X.II.A of that proposal preamble (86 FR 63186; November 15, 2021). In the November 2021 proposal, the EPA proposed new work practice standards for the collection of fugitive emissions components located at well sites. The EPA proposed that well sites with total site-level baseline methane emissions less than 3 tpy would demonstrate, based on a one-time site-specific survey, that actual emissions are reflected in the baseline methane emissions calculation. For well sites with total site-level baseline methane emissions of 3 tpy or greater, the EPA proposed quarterly OGI or EPA Method 21 monitoring. The EPA also co-proposed an alternative set of work practice standards: for well sites with total site-level baseline methane emissions of 3 tpy or greater and less than 8 tpy semiannual OGI or EPA Method 21 monitoring would apply; and for well sites with total site-level baseline methane emissions of 8 tpy or greater, quarterly OGI or EPA Method 21 monitoring would apply. For sites using OGI to detect fugitive emissions under any of these proposed work practice standards, the EPA proposed that surveys would be conducted according to the procedures proposed as appendix K. See section VI of this preamble for more information regarding appendix K.

ii. Changes to Proposal and Rationale

The EPA is proposing certain changes to the November 2021 proposal standards for NSPS OOOOb. Specifically, the EPA is proposing: (1) To require OGI monitoring for well sites and centralized production facilities following the monitoring plan required in proposed 40 CFR 60.5397b instead of requiring the procedures being proposed in appendix K for these sites; (2) to expand the affected facility definition to include wellhead only well sites, which were previously exempt, and add a subcategory for small well sites; (3) to revise the definition of fugitive emissions component; (4) to require periodic AVO or other detection methods for all well sites and centralized production facilities (except those located on the Alaskan North Slope) at frequencies based on the subcategory of well site; (5) to require periodic OGI fugitive emissions monitoring based on the number and type of equipment located at the well site, in lieu of the baseline emissions calculations required in the November 2021 proposal; and (6) to include requirements for well closures that would indicate when fugitive emissions monitoring could stop.

Appendix K. The EPA is not including a requirement to conduct OGI

monitoring according to the proposed appendix K for well sites or centralized production facilities, as was proposed in the November 2021 proposal. Instead, the EPA is proposing to require OGI surveys following the procedures specified in the proposed regulatory text for NSPS OOOOb (at 40 CFR 60.5397b) or according to EPA Method 21. The EPA received extensive comments²⁵ from oil and gas operators and other groups on the numerous complexities associated with following the proposed appendix K, especially considering the remoteness and size of many of these sites. In addition, commenters pointed out that OGI has always been the BSER for fugitive monitoring at well sites and was never designed as a replacement for EPA Method 21, while appendix K was designed for use at more complex processing facilities that have historically been subject to monitoring following EPA Method 21. The EPA agrees with the commenters and is proposing requirements within NSPS OOOOb at 40 CFR 60.5397b in lieu of the procedures in appendix K for fugitive emissions monitoring at well sites or centralized production facilities. See section VI of this preamble for additional information on what the EPA is proposing for appendix K related to other sources (e.g., natural gas processing plants).

Affected facility and subcategorization of well sites. The EPA is proposing to expand the affected facility definition to include the collection of fugitive emissions components at all well sites, including the previously excluded wellhead only well sites. Various studies, including a recent U.S. Department of Energy funded study on quantifying methane emissions from marginal wells,²⁶ demonstrate that fugitive emissions do occur from wellheads, and in some cases can be significant. As discussed in detail later in this section, the EPA evaluated emissions reductions resulting from the implementation of a fugitive emissions monitoring and repair program for a range of well site and centralized production facility

configurations, ranging from the single wellhead only well site, to sites with specific major production and processing equipment present. While different types of monitoring techniques were found appropriate at the various site configurations evaluated, the EPA did not find support for an exemption of any site from the standards. Therefore, the EPA is proposing to define the affected facility as the collection of fugitive emissions components located at a well site or centralized production facility with no exemptions.

Further, the EPA is proposing monitoring and repair programs specific to four distinct subcategories of well sites: (1) Single wellhead only well sites,²⁷ (2) wellhead only well sites with two or more wellheads, (3) well sites and centralized production facilities²⁸ with major production and processing equipment, and (4) small well sites. The third subcategory includes well sites and centralized production facilities that have: (1) One or more controlled storage vessels, (2) one or more control devices, (3) one or more natural gas-driven pneumatic controllers or pumps, or (4) two or more other major production and processing equipment. The fourth subcategory, small well sites, are single wellhead well sites that do not contain any controlled storage vessels, control devices, pneumatic controller affected facilities, or pneumatic pump affected facilities, and include only one other piece of major production and processing equipment. Major production and processing equipment that would be allowed at a small well site would include a single separator, glycol dehydrator, centrifugal and reciprocating compressor,²⁹ heater/treater, and storage vessel that is not controlled. By this definition, a small well site could only potentially contain

a well affected facility (for well completion operations or gas well liquids unloading operations that do not utilize a CVS to route emissions to a control device) and a fugitive emissions components affected facility. No other affected facilities, including those utilizing CVS (such as pneumatic pumps routing to control) can be present for a well site to meet the definition of a small well site. The proposed monitoring requirements for each of these subcategories is described in more detail later in this section.

Definition of fugitive emissions component. The EPA is proposing specific revisions to the definition of fugitive emissions component that was included in the November 2021 proposal. First, the EPA is proposing to add yard piping as one of the specifically enumerated components in the definition of a fugitive emissions component. While not common, pipes can experience cracks or holes, which can lead to fugitive emissions. The EPA is proposing to include yard piping in the definition of fugitive emissions component to ensure that when fugitive emissions are found from the pipe itself the necessary repairs are completed accordingly.

Second, the EPA is correcting an error made in the November 2021 proposal. The EPA had proposed that all thief hatches and other openings on all controlled storage vessels would be considered fugitive emissions components. This definition inadvertently included storage vessels that would already be subject to control as storage vessel affected facilities/designated facilities, including regular inspections of thief hatches and other sources of fugitive emissions that are separately required as part of the proposed standards for storage vessel affected facilities/designated facilities (see section IV.I of this preamble). The EPA is correcting that error in this supplemental proposal to avoid establishing redundant or duplicative requirements. Instead, the EPA is defining fugitive emissions components to include all thief hatches and other openings on storage vessels that are constructed, reconstructed, or modified after November 15, 2021, and not also subject to control as storage vessel affected facilities. This would include thief hatches and other openings on both uncontrolled storage vessels and storage vessels that are controlled for other purposes but not subject to NSPS OOOOb control requirements because fugitive emissions can occur from these components.

Third, the EPA is not defining control devices as fugitive emissions

²⁵ See Document ID Nos. EPA-HQ-OAR-2021-0317-0579, EPA-HQ-OAR-2021-0317-0743, EPA-HQ-OAR-2021-0317-0764, EPA-HQ-OAR-2021-0317-0777, EPA-HQ-OAR-2021-0317-0782, EPA-HQ-OAR-2021-0317-0786, EPA-HQ-OAR-2021-0317-0793, EPA-HQ-OAR-2021-0317-0802, EPA-HQ-OAR-2021-0317-0807, EPA-HQ-OAR-2021-0317-0808, EPA-HQ-OAR-2021-0317-0810, EPA-HQ-OAR-2021-0317-0814, EPA-HQ-OAR-2021-0317-0817, EPA-HQ-OAR-2021-0317-0820, EPA-HQ-OAR-2021-0317-0831, EPA-HQ-OAR-2021-0317-0834, and EPA-HQ-OAR-2021-0317-0938.

²⁶ Bowers, Richard L. *Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells*. United States. <https://doi.org/10.2172/1865859>.

²⁷ The EPA defines a wellhead only well site as a well site that contains one or more wellheads and no major production and processing equipment.

²⁸ Centralized production facilities include 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.

²⁹ The EPA is proposing to exclude compressors that are located at well sites from the definition of a centrifugal affected facility and reciprocating affected facility, consistent with the November 2021 proposal. See 86 FR 63180 (November 15, 2021).

components. One commenter stated that emissions resulting from noncompliance with control device requirements should not also be defined as fugitive emissions.³⁰ This commenter opined that since control devices are inherently designed to have emissions, even when well operated, it should be expected that some amount of methane and VOC would be detected during an OGI survey for fugitive emissions. The EPA agrees that control devices should not be treated as fugitive emissions components and is therefore revising the definition in this proposal to not include those devices. Further, as discussed in more detail in section IV.H of this preamble, the EPA anticipates that control devices are used to meet at least one of the emissions standards in the proposed rules, and as such, they would be subject to the control device requirements in NSPS OOOOb or EG OOOOc. See section IV.H of this preamble for additional discussion on proposed requirements specific to control devices.

Finally, the EPA is not maintaining the inclusion of natural gas-driven pneumatic controllers or natural gas-driven pneumatic pumps as fugitive emissions components. These devices are both separate affected facilities with separate standards identified as BSER.³¹ See sections IV.D and IV.E of this preamble for information about the proposed BSER for natural gas-driven pneumatic controllers and natural gas-driven pneumatic pumps, respectively.

The EPA is proposing specific requirements throughout this supplemental proposal that will address emissions from controlled storage vessels and natural gas-driven pneumatic controllers and pumps, including requirements for quarterly OGI monitoring. These monitoring requirements provide compliance assurance that the proposed performance standards for these sources are being complied with and obviate any need to include these sources in the definition of a fugitive emissions component. For control devices, the EPA is proposing additional initial and continuous compliance measures to ensure the required emissions

reductions are being achieved. See sections IV.D for discussion on pneumatic controllers, IV.E for discussion on pneumatic pumps, IV.H for discussion on combustion control devices, IV.J for discussion on storage vessels, and IV.K for discussion on covers and CVS.³²

Comments received on monitoring requirements. As discussed in the November 2021 proposal, the EPA proposed to require fugitive emissions monitoring using OGI based on the site-level methane baseline emissions, as determined, in part, through equipment and component count emissions factors. Further, the EPA solicited comment on adding routine AVO monitoring in addition to periodic OGI monitoring to help identify potential large emission events. Several comments, mostly from small businesses, were received regarding the use of AVO inspections because these are low cost and simple inspections that would identify indications of leaks, such as open thief hatches on storage vessels. These comments ranged from requiring monthly to annual AVO inspections in lieu of OGI monitoring, to requests to minimize the complexity of any associated recordkeeping and reporting requirements should the EPA require this type of inspection.³³

The EPA received substantive comments from several commenters on the November 2021 proposal regarding OGI monitoring arguing that the proposed requirements for well sites were unreasonable and would be difficult to implement, especially for well sites with total site-level baseline methane emissions less than 3 tpy. Specifically, these commenters³⁴ asserted that there would be challenges around calculating the site-level baseline emissions and that this task would be burdensome, while other commenters³⁵ asserted the calculations would result in no regular monitoring at sites that have leak-prone equipment. Further, commenters noted that it would be difficult to verify the

emissions calculations, which could result in compliance and/or enforcement challenges. According to industry commenters,³⁶ the requirement to repeat the calculation when equipment is added or removed from the site would be especially burdensome. One of the commenters further stated this requirement would force owners and operators to constantly maintain an inventory of equipment, with some operators carrying this burden for hundreds to thousands of sites.³⁷ Moreover, the commenter indicated that the EPA has not explained the need for the proposed recalculation of site-level methane emissions based on equipment changes and how this would have an environmental benefit. Another commenter argued that the EPA did not properly explain the basis for the emissions thresholds and disagreed with the components and equipment included in the calculation, as well as the use of the GHGRP emissions factors.³⁸

In response to the proposed site-specific survey to demonstrate that actual emissions are reflected in the baseline emissions calculation, some commenters asserted that well sites with emissions less than 3 tpy should not be exempt from regular monitoring. According to commenters, even small sites can have leaks with significant emissions.³⁹ For this reason, the commenters made the case that regular monitoring should be required for all sites. Some commenters also expressed that the requirement to calculate site-level methane baseline emissions and conduct an initial survey was confusing. As explained by one commenter, “[the] EPA states well sites with site-level baseline methane emissions [less than] 3 tpy are not required to conduct OGI monitoring.”⁴⁰ See 86 FR 63171 (November 15, 2021); however, since the EPA also proposed that well sites would be required to perform a survey to confirm that the actual emissions are less than 3 tpy, the commenter viewed this as a contradiction within the rule, thus making it unclear what the EPA was proposing.

One commenter indicated that monitoring should also be required for

³⁰ See Document ID No. EPA-HQ-OAR-2021-0317-0808.

³¹ As explained in sections IV.D for pneumatic controllers and IV.E for pneumatic pumps, only natural gas-driven pneumatic controllers and pumps are defined as affected facilities. For a controller or pump to not be an affected facility, it would need to be electric or solar, which would not have the potential to emit methane or VOC emissions. Therefore, the EPA does not consider pneumatic controllers or pneumatic pumps part of the fugitive emissions components when they are not affected facilities as controllers or pumps.

³² The EPA notes quarterly OGI monitoring will also be performed to demonstrate compliance with specific standards for controlled storage vessels, natural gas-driven pneumatic controllers, natural gas-driven pneumatic pumps, and CVS associated with any affected facilities at well sites. This quarterly OGI monitoring would take place during the same quarterly OGI monitoring of the fugitive emissions components affected facility located at the same well site.

³³ See Document ID Nos. EPA-HQ-OAR-2021-0317-0585, EPA-HQ-OAR-2021-0317-0814, EPA-HQ-OAR-2021-0317-0822, EPA-HQ-OAR-2021-0317-0929, and EPA-HQ-OAR-2021-0317-0935.

³⁴ See Document ID Nos. EPA-HQ-OAR-2021-0317-0808 and EPA-HQ-OAR-2021-0317-0814.

³⁵ See Document ID No. EPA-HQ-OAR-2021-0317-0844.

³⁶ See Document ID Nos. EPA-HQ-OAR-2021-0317-0808 and EPA-HQ-OAR-2021-0317-0814.

³⁷ See Document ID No. EPA-HQ-OAR-2021-0317-0808.

³⁸ See Document ID No. EPA-HQ-OAR-2021-0317-0814.

³⁹ See Document ID Nos. EPA-HQ-OAR-2021-0317-0568, EPA-HQ-OAR-2021-0317-0769, EPA-HQ-OAR-2021-0317-0844, and EPA-HQ-OAR-2021-0317-1267.

⁴⁰ See Document ID No. EPA-HQ-OAR-2021-0317-0727.

wellhead only well sites because, even though less equipment (and so fewer components) is present at a wellhead only well site, the wellhead itself is a source of emissions, which should be inspected for fugitive emissions.⁴¹ Other commenters provided similar comments and urged the EPA to remove the exemption for wellhead only well sites because these well sites have other smaller equipment that leaks and malfunctions,⁴² with large emissions having been observed from these sites,⁴³ even though these sites do not have major production and processing equipment. Further, commenters noted that well sites with equipment with potentially significant emissions should not be considered a wellhead only well site or excluded from regular monitoring. The commenter urged the EPA that, if the wellhead only well site exemption is retained, it must only apply to single wellhead sites. Even if no associated equipment is located at a wellhead only well site, sites with multiple wellheads can have a number of components and subsequently potential sources of fugitive emissions.⁴⁴ This same commenter, who opposes the 3 tpy threshold, noted that “failure prone equipment” such as storage vessels, separators, flares, and natural gas-driven pneumatic controllers often operate incorrectly and can cause significant emissions.⁴⁵ This commenter argued that sites with this type of equipment should be required to monitor on a frequent basis.

Another commenter noted that the one-time survey for sites less than 3 tpy does not address the problem of future leaks or malfunctions.⁴⁶ The commenter indicated that malfunctions account for a large amount of methane emissions and the commenter, therefore, recommended at least annual monitoring. Comments urging the EPA to exempt small, low producing wells were also received.⁴⁷ Specifically, one commenter argued that low producing wells are not disproportionately large emitters.⁴⁸ This commenter asked that the EPA exempt these wells, asserting that these sources can least afford monitoring and have relatively small

emissions. The commenter further asked that the rule exempt wells defined by states as stripper wells.

As illustrated by the comments, which specifically highlight many potential challenges related to implementation, compliance assurance, and efficacy in reducing emissions, the EPA agrees that the fugitive emissions monitoring program that was proposed in the November 2021 proposal should be clarified and improved in order to address the issues identified by the various commenters. As explained below, after considering the comments, additional data, and a revised analysis, the EPA is proposing revised fugitive emissions applicability criteria, monitoring frequencies, and detection methods at well sites and centralized production facilities.

Fugitive emissions monitoring and repair modeling. In the November 2021 proposal, the EPA also solicited comment on other thresholds that could be used to set monitoring requirements for well sites, in lieu of using self-reported baseline emissions as a threshold. One of these options included an equipment-based approach, in which well sites with specific leak-prone equipment would have one set of requirements, while well sites with other equipment (or that lack leak-prone equipment) would have a different set of requirements. In comparison to a self-reported baseline emissions threshold, such an approach would ensure routine OGI monitoring takes place at sites that have equipment that is most likely to have fugitive emissions more frequently, while also being more straightforward for owners and operators to implement and for the EPA and state regulators to verify and enforce. The EPA received feedback and additional information in response to this solicitation and used that information to develop a new analysis based on this equipment-based concept.

To evaluate an equipment-based program, the EPA developed three distinct model plants. These model plants were designed to account for various equipment types located at sites and ranged from single wellhead only well sites to complex sites with various known sources of large emissions present. Specifically, these model plants include: (1) Single wellhead only well sites,⁴⁹ (2) wellhead only well sites with

two or more wellheads, and (3) well sites or centralized production facilities⁵⁰ with major production and processing equipment. For the reasons explained later in this section, the EPA finds that small well sites have component counts, and thus emissions distributions, that are more comparable to single wellhead only well sites and less than multi-wellhead only well sites. The EPA has not modeled this small well site subcategory. Fugitive emissions from small well sites would originate from the same types of components (e.g., valves, connectors, open-ended lines, or pressure relief devices) modeled with emissions for single wellhead only well sites, and the available data suggests that the single piece of equipment at the site would be of smaller size, and thus have fewer individual components, than those summarized for well sites and centralized production facilities with major production and processing equipment. However, for purposes of summarizing the component counts, the EPA is including small well sites in Table 7 along with the details of the number and type of equipment included in each of the model plants used for emissions modeling. The EPA finds that evaluating several types of model plants based on equipment and component counts is consistent with the empirical literature on fugitive emissions, including the conclusion from the U.S. Department of Energy’s (DOE) recent marginal well study that a strong correlation was observed between the major equipment count and the frequency of fugitive emissions.^{51 52} The

water. The EPA does not consider meters and yard piping as major production and processing equipment for purposes of determining if a well site is a wellhead only well site.

⁵⁰ Centralized production facilities include 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.

⁵¹ Bowers, Richard L. *Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells*. United States. <https://doi.org/10.2172/1865859>.

⁵² The U.S. DOE marginal well study did not collect information on individual component counts on major equipment but did find a strong correlation to emissions based on the size of the site (defined by the major equipment count). Thus, the proposed definition of a small well site is limited

Continued

⁴¹ See Document ID No. EPA-HQ-OAR-2021-0317-0769.

⁴² See Document ID No. EPA-HQ-OAR-2021-0317-0586.

⁴³ See Document ID No. EPA-HQ-OAR-2021-0317-0844.

⁴⁴ Id.

⁴⁵ Id.

⁴⁶ See Document ID No. EPA-HQ-OAR-2021-0317-1267.

⁴⁷ See Document ID Nos. EPA-HQ-OAR-2021-0317-0425 and EPA-HQ-OAR-2021-0317-0814.

⁴⁸ See Document ID No. EPA-HQ-OAR-2021-0317-0425.

⁴⁹ The EPA defines a wellhead only well site as a well site that contains one or more wellheads and no major production and processing equipment. Major production and processing equipment includes reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced

EPA is soliciting comment on the proposed model plants described in Table 7. The EPA is also seeking

information on how to refine its approach to modeling fugitive emissions

in the model plants developed for this analysis.

TABLE 7—WELL SITE MODEL PLANT COMPONENT COUNTS

Major equipment at well site	Count	Number of components at well site			
		Valves	Connectors	Open ended lines	Pressure relief valves
Single Wellhead Only Well Sites					
Gas Wellheads	1	10	38	1	0
Meter/Piping	1	13	48	1	1
Total # of Components:	112				
Small Well Sites					
Gas Wellheads	1	10	38	1	0
Meter/Piping	1	13	48	1	1
Other Equipment ^a	1	9	34	1	1
Total # of Components:	157				
Wellhead Only Well Sites with Two or More Wellheads					
Gas Wellheads	2	19	75	2	0
Meter/Piping	2	26	96	1	1
Total # of Components:	220				
Well Sites and Centralized Production Facilities with Major Production and Processing Equipment					
Gas Wellheads	2	19	75	2	0
Meter/Piping	2	26	96	1	1
Separators	2	44	137	8	3
In-Line Heaters	1	14	65	2	1
Dehydrators	1	24	90	2	2
Storage Vessel Thief Hatch	1	0	0	0	0
Total # of Components:	612				

^a Major production and processing equipment that could be at a small well site includes compressors, glycol dehydrators, heater/treaters, separators, and uncontrolled storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water. Small well sites cannot include one or more controlled storage vessels, control device, natural gas-driven pneumatic controllers, or natural gas-driven pneumatic pumps. The component counts provided in this table are based on the average number of valves identified in industry provided data for a small well site (34 valves) and assuming 3.8 connectors per valve, 1 open-ended line, and 1 pressure relief device consistent with component counts provided for other equipment.⁵³

In previous rulemakings, the EPA used component-level emissions factors that commenters on previous actions have stated are dated and not reflective of emissions detected through various recent measurement studies to determine baseline emissions and emissions reductions at various OGI monitoring frequencies.⁵⁴ In contrast, several comments on the November 2021 proposal identified various modeling simulation tools that can be utilized for this same purpose and that build in emissions data from various emissions measurement campaigns providing empirical emissions data.

One such modeling simulation tool is the Fugitive Emissions Abatement

Simulation Toolkit (FEAST). FEAST is an open-source modeling framework developed to evaluate the effectiveness of fugitive emissions programs at oil and gas facilities by simulating various scenarios of leaks (and subsequent repairs) occurring over time using an empirical leak dataset according to a randomized process. FEAST supports a variety of detection technologies, including OGI, aerial surveys, drone surveys, and continuous monitoring systems and can model hybrid programs (e.g., aerial surveys followed by ground-level OGI surveys). The effects of fugitive emissions monitoring and repair are simulated based on probability of detection (PoD) curves (or

surfaces) for each monitoring method, which indicate the probability that a leak of a given size will be detected within a given survey (or time period for continuous monitoring technologies), and survey times (frequencies) are accounted for as finite time periods. The emissions present at the site during the modeled period of time are quantified, accounting for leak generation, identification, and repair, and emissions reductions can be calculated by comparing the simulated fugitive emissions program against a baseline scenario where no program is implemented.

The EPA recognizes there are several options to identify fugitive emissions,

to inclusion of a single piece of specific major production and processing equipment.

⁵³ See Document ID No. EPA-HQ-OAR-2017-0483-1006.

⁵⁴ See *EPA Responses to Public Comments on Reconsideration of New Source Performance Standards (NSPS) Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and*

Modified Sources Reconsideration 40 CFR part 60, subpart OOOOa, located at Document ID No. EPA-HQ-OAR-2017-0483-2291.

ranging from simple sensory methods to advanced detection technologies. The EPA solicited comment on the inclusion of simple AVO checks that could be performed in conjunction with periodic OGI monitoring surveys to identify large emissions between OGI monitoring surveys in the November 2021 proposal. The EPA maintains that it is imperative to ensure that well sites and centralized production facilities are operated in a manner such that emissions are minimized. Further, OGI or other detection technologies are not necessary for identifying fugitive emissions from certain fugitive emissions components, such as open thief hatches. Therefore, the EPA examined the use of regular AVO inspections to provide for potential additional emissions reductions associated with fugitive emissions components, and to compel operators to address issues whenever they find indications of a potential leak during regular visits to sites.

One factor that can lead to fugitive emissions is a lack of maintenance, and it has been shown that when sites are not regularly visited, fugitive emissions can occur for long periods of time without any mitigation. For example, in comments provided on the October 15, 2018 proposed reconsideration for NSPS OOOOa, it was reported that some sites can be operating in a state of disrepair, including rusty well shafts, broken valves, or fallen trees on equipment.⁵⁵ While OGI and other monitoring technologies can be useful in identifying emissions from individual components, such as valves and connectors, these technologies require expensive equipment and specialized training of

operators for identifying indications of fugitive emissions resulting from broken equipment or open thief hatches. On the other hand, AVO inspections are a useful tool for identifying when there are indications of a potential leak without the need for expensive equipment or specialized training of operators. For example, at sites that lack extensive background noise, a person would be able to hear if a high-pressure leak is present, which could present as a hissing sound. Field gas produced at well sites contains a mixture of methane and various VOCs, which have the potential to be detected by smell. Where the field gas contains a lot of condensate or other produced liquids, any resulting leaks would present as indications of liquids dripping or potentially puddles forming on the ground. In cold climates, ice formation on components could also indicate a potential leak. Finally, an open thief hatch on a storage vessel is easily identified with visual inspection.

The EPA is proposing a revised approach to address fugitive emissions at well sites and centralized production facilities that establishes the monitoring frequency and detection method (AVO and/or OGI) based on results obtained from using FEAST⁵⁶ to model various programs at the three model plants presented in this preamble. First, the EPA determined baseline methane emissions from each of the model plants using two leak generation rates, 0.5 and 1.0 percent. These leak generation rates represent the percentage of components leaking at any particular time at the site. The EPA chose these leak generation rates as a starting point for modeling to compare against measured emissions

documented in credible empirical studies, such as the August 2021 paper by Rutherford, *et al.*⁵⁷ This proposed approach is responsive to feedback from commenters indicating that the emissions factors we relied upon in the November 2021 proposal undercount fugitive emissions, and recommending that we utilize models based on recent measured data that is more representative of fugitive emissions in the field. The results of the FEAST simulations for AVO and OGI monitoring are presented in the remainder of this section for each of the model plants. For ground based OGI, the EPA used a minimum detection limit of 60 g/hr consistent with the proposed camera specifications in 40 CFR 60.5397b(c)(7)(i)(B)⁵⁸ and assumed all leaks identified by OGI would be repaired within 30 days, consistent with the average repair time that would be required for fugitive emissions components.⁵⁹ The results of these models provide an estimate of the number of leaks identified during an inspection and the potential emissions reductions, which the EPA then applied to its cost-effectiveness analysis to determine the BSER for each well site model plant. The EPA is seeking information on its estimates of repair costs associated with identified leaks.

For purposes of evaluating the costs of the AVO inspections and OGI monitoring surveys, the EPA incorporated specific revisions into the cost analysis presented in the November 2021 proposal.⁶⁰ The capital and annual costs associated with each type of inspection or monitoring program are presented in Tables 8 and 9.

TABLE 8—WELL SITE MODEL PLANT COSTS ASSOCIATED WITH OGI MONITORING

Description of item	Costs (\$)
Capital Costs for OGI Inspections	
Read rule and instructions (per 22 well sites)	\$260.
Develop monitoring plan (per 22 well sites)	\$2,600.
Setup recordkeeping system (per well site)	\$900.
Costs for OGI Inspections (per well site)	
OGI surveys	\$142/hr.
Repairs	\$146 to \$330/yr.
Resurvey	\$3 to \$20/yr.
Annual licensing fees of recordkeeping system	\$870/yr.
Annual administrative costs for recordkeeping/data management	\$325/yr.

⁵⁵ See Document ID No. EPA-HQ-OAR-2017-0483-2240.

⁵⁶ The EPA used FEAST version 3.1 to model the various programs. While the EPA used FEAST in this modeling exercise, the EPA would expect other available modeling simulation tools to produce similar results.

⁵⁷ Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. *et al.* Closing the methane gap in US oil and natural gas production emissions inventories. *Nat Commun* 12, 4715 (2021). <https://doi.org/10.1038/s41467-021-25017-4>.

⁵⁸ The EPA is adopting the same OGI camera specifications for fugitive emissions components as those in NSPS OOOOa.

⁵⁹ The EPA is proposing to require a first attempt at repair within 30 days of identifying fugitive emissions, with final repair required within 30 days of the first attempt.

⁶⁰ See November 2021 TSD for additional information on costs of OGI monitoring at Document ID No. EPA-HQ-OAR-2021-0317-0166.

TABLE 8—WELL SITE MODEL PLANT COSTS ASSOCIATED WITH OGI MONITORING—Continued

Description of item	Costs (\$)
Prepare and submit information in annual report	\$195/yr.

TABLE 9—WELL SITE MODEL PLANT COSTS ASSOCIATED WITH AVO INSPECTIONS (ASSUMES NO OGI MONITORING)

Description of item	Costs (\$)
Capital Costs for AVO Inspections	
Read rule and instructions (per 22 well sites)	\$260.
Develop monitoring plan (per 22 well sites)	\$260.
Setup recordkeeping system (per well site)	\$65.
Costs for AVO Inspections (per well site)	
AVO inspection, including preparation and documentation	\$65/hr.
Repairs	\$89/yr to \$178/yr.
Resurvey	\$5/yr to \$11/yr.
Prepare and submit information in annual report	\$65/yr.

For OGI monitoring at well sites, the capital costs presented in Table 8 remain unchanged from the November 2021 proposal. The capital costs associated with the fugitive emissions program are expected to be the same for each model plant because these capital costs include the cost of developing a fugitive emission monitoring plan and purchasing or developing a recordkeeping data management system specific to fugitive emissions monitoring and repair. More discussion about the capital costs, which remain unchanged in this proposal, can be found in section XII.A.1.a of the November 2021 proposal (86 FR 63189; November 15, 2021).

When evaluating the annual costs of the fugitive emissions monitoring and repair requirements (*i.e.*, monitoring, repair, repair verification, data management licensing fees, recordkeeping, and reporting), the EPA considers costs at the individual site level. Estimates for these costs for OGI monitoring were mostly retained and consistent with the November 2021 proposal. However, the EPA incorporated the results of FEAST modeling for the newly developed model plants to include the modeled number of components identified as leaking, thus requiring repairs.⁶¹ Even though the leak generation rate used in the FEAST model was set to 0.5 and 1.0 percent for purposes of emissions reduction analyses, the empirical dataset used includes all leaks measured across numerous studies, many of which are below the expected mass

detection limit of OGI cameras. As such, only a portion of the leaks generated are identified and repaired via the OGI monitoring program (approximately 57 percent in this analysis). Specifically, the estimated annual number of components requiring repair resulting from an OGI survey, as modeled by FEAST, were 0.62 for single wellhead only and small well sites, 1.25 for multi-wellhead only well sites, and 3.7 for well sites and centralized production facilities with major production and processing equipment. The EPA utilized the same repair costs and resurvey costs as in the November 2021 proposal for OGI monitoring. All other inputs to the annual costs remain unchanged from the November 2021 proposal as well.

The estimated annual costs of the OGI-based fugitive emissions program at well sites and centralized production facilities range from \$2,100 for annual monitoring to \$6,000 for monthly monitoring for single wellhead only well sites. For multi-wellhead only well sites, the estimated annual costs of the fugitive emissions program range from \$2,000 for annual monitoring to \$5,900 for monthly monitoring. For well sites with major production and processing equipment, including those with controlled tanks, the estimated annual costs of the fugitive emissions program are estimated to range from \$2,300 for annual monitoring to \$7,000 for monthly monitoring. More detailed information on the capital and annual costs estimated for the fugitive emissions program can be found in the November 2021 TSD⁶² and in the

Supplemental TSD for this action located at Docket ID No. EPA-HQ-OAR-2021-0317.

For this supplemental proposal, the EPA separately evaluated the costs associated with AVO monitoring. The EPA assumed capital and annual costs for each individual well site and evaluated the costs in two ways: (1) Assuming an operator visits the site at least as frequently as the inspection (no additional travel costs), and (2) assuming additional travel costs because the site is not visited at the same frequency as the inspection. When accounting for the second scenario, the EPA assumed a travel time of 1.25 hours round trip and applied the same hourly rate for operators as is used for the development of a monitoring plan and other actions. Further, the EPA assumes an inspection time ranging from 15 minutes (single wellhead only well sites) to 1 hour (centralized production facilities) to account for the added complexity at larger sites. The EPA also assumed 1 repair per year for the single wellhead only, multi-wellhead only, and small well sites, and 2 repairs per year for larger well sites and centralized production facilities. While there is a lack of information on the emissions reductions achieved through an AVO inspection, the EPA is confident that specific indications of potential leaks (*e.g.*, open valves or thief hatches) would be obvious to any operator performing these inspections and discusses these in more detail below for each model plant.

The estimated annual costs of the AVO inspections at single wellhead only well sites and small well sites that are visited at least as frequently as the

⁶¹ Assumes an average of 0.62, 1.25, and 3.7 leaks found annually, for model plants 1–3, respectively.

⁶² See Document ID No. EPA-HQ-OAR-2021-0317–0166.

AVO inspection frequency range from \$214 for annual inspections to \$660 for monthly inspections. These estimates range from \$300 for annual inspections to \$1,630 for monthly inspections if additional travel costs are incorporated for these sites. For multi-wellhead only well sites, the estimated annual costs range from \$265 for annual inspections to \$1,150 for monthly inspections, and these costs range from \$350 for annual inspections to \$2,120 for monthly inspections when additional travel costs are added. For well sites with major production and processing equipment, the estimated annual costs range from \$480 for annual inspections to \$2,650 for monthly inspections, and this range increases to \$560 for annual inspections to \$3,620 for monthly inspections when additional travel costs are incorporated. More detailed information on the capital and annual costs estimated for the AVO inspections can be found in the Supplemental TSD for this action located at Docket ID No. EPA-HQ-OAR-2021-0317. The EPA is soliciting comment on all aspects of the estimated costs of the AVO inspection program, including labor rates and the costs of repair.

Single wellhead only well sites. The EPA has not previously defined single wellhead only well sites as fugitive emissions components affected facilities. For a single wellhead only well site, the most likely cause of emissions would be from an open valve allowing venting from the wellhead. In the U.S. DOE marginal well study, two of the top 10 largest leaks found were located at the wellhead and were the

result of an open valve on the well surface casing, which allowed venting to the atmosphere. These two sources resulted in emissions of 6.9 kg/hr methane (66 tpy) and 7.8 kg/hr methane (76 tpy).⁶³ A third leak, also located at the wellhead, was identified as a hole in the side of the surface casing, resulting in emissions of 2.9 kg/hr methane (28 tpy) from this source. The other top 10 leak sources identified in the U.S. DOE marginal well study were on equipment that is not present at a single wellhead only well site (e.g., separators or storage vessels). The types of emissions sources located at the wellhead, including these large emissions sources found in the U.S. DOE marginal well study, can be easily identified using AVO inspections and would not require the use of OGI for identification. Therefore, the EPA evaluated a periodic AVO inspection and repair program for addressing fugitive emissions from single wellhead only well sites.

First, the EPA modeled an AVO program at two leak generation rates (1.0 percent and 0.5 percent) to compare the resulting baseline methane emissions against empirical emissions data and identify which model results more closely reflect real-world emissions measurement campaign results. A comparison of the baseline methane emissions estimated at both of these leak generation rates to empirical data suggest that the 0.5 percent leak generation rate is more likely to be indicative of the actual average emissions from single wellhead only well sites. Various studies indicate that, while these sites can occasionally

experience large emissions events, such events are not as frequent as at more complex sites, and thus do not warrant application of a higher average emissions baseline for purposes of determining the BSER for these sites.⁶⁴ The U.S. DOE marginal well study⁶⁵ measured methane average population emissions ranging from 0.26 to 0.56 tpy from wellheads examined during the study, with negligible emissions reported from meters. Similarly, the 2021 Rutherford *et al.* study estimated an average emissions factor for a single wellhead of 3.4 kg/day (0.95 tpy) and a single meter of 2.7 kg/day (0.75 tpy) for a total of 1.70 tpy from a single wellhead only well site.⁶⁶ Using the average emissions between these 2 studies, the baseline methane emissions are 1.13 tpy, which is consistent with the 0.5 percent leak generation rate results for our single wellhead only well sites, for which the FEAST model estimated a methane emissions baseline of 1.27 tpy (see Table 8). By contrast, the 1.0 percent leak generation rate baseline (2.97 tpy) is more than five times higher than the high end of the U.S. DOE marginal well study and 50 percent higher than the estimates from the Rutherford, *et al.* study. Therefore, the EPA is evaluating the cost of control for AVO inspections based on the modeled results for a 0.5 percent leak generation rate at single wellhead only well sites. Additional details of the model results, including those for the 1.0 percent leak generation rate, are included in the Supplemental TSD for this action located at Docket ID No. EPA-HQ-OAR-2021-0317.

TABLE 10—SUMMARY OF EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS: AVO INSPECTIONS AT SINGLE WELLHEAD ONLY WELL SITES

Monitoring frequency	Annual cost (\$/yr/site)	Methane emission reduction (tpy/site)	VOC emission reduction (tpy/site)	Cost-effectiveness		Incremental cost-effectiveness	
				Methane (\$/ton)	VOC (\$/ton)	Methane (\$/ton)	VOC (\$/ton)
Single Wellhead Well Sites: Includes additional travel costs Single Pollutant Approach							
Annual	\$296	0.11	0.03	\$2,579	\$9,278		
Semiannual	417	0.40	0.11	1,048	3,769	\$429	\$1,543
Quarterly	660	0.56	0.16	1,181	4,249	1,511	5,436
Bimonthly	904	0.63	0.17	1,443	5,190	3,618	13,017
Monthly	1,633	0.69	0.19	2,367	8,515	11,455	41,208
Single Wellhead Well Sites: Includes additional travel costs Multipollutant Approach							
Annual	296	0.11	0.03	1,289	4,639		

⁶³ Bowers, Richard L. *Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells*. United States. <https://doi.org/10.2172/1865859>. See Table 2 of the study for details on the top 10 emissions sources identified.

⁶⁴ See <https://pubs.acs.org/doi/10.1021/acs.est.0c02927>, <https://data.permianmap.org/>

[pages/flaring](https://www.edf.org/sites/default/files/documents/PermianMapMethodology_1.pdf), and https://www.edf.org/sites/default/files/documents/PermianMapMethodology_1.pdf.

⁶⁵ Bowers, Richard L. *Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells*. United States. <https://doi.org/10.2172/1865859>. Marginal wells are defined in this study as producing less than 15

barrels of oil equivalent per day (boe/day) of combined oil and natural gas.

⁶⁶ Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. *et al.* Closing the methane gap in US oil and natural gas production emissions inventories. *Nat Commun* 12, 4715 (2021). <https://doi.org/10.1038/s41467-021-25017-4>.

TABLE 10—SUMMARY OF EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS: AVO INSPECTIONS AT SINGLE WELLHEAD ONLY WELL SITES—Continued

Monitoring frequency	Annual cost (\$/yr/site)	Methane emission reduction (tpy/site)	VOC emission reduction (tpy/site)	Cost-effectiveness		Incremental cost-effectiveness	
				Methane (\$/ton)	VOC (\$/ton)	Methane (\$/ton)	VOC (\$/ton)
Semiannual	417	0.40	0.11	524	1,885	214	771
Quarterly	660	0.56	0.16	591	2,124	756	2,718
Bimonthly	904	0.63	0.17	721	2,595	1,809	6,509
Monthly	1,633	0.69	0.19	1,183	4,257	5,727	20,604

It is the EPA's understanding that single wellhead only well sites are not regularly visited. Instead, these sites are expected to only be visited when specific operations are necessary that require the presence of an operator on the site (e.g., well workovers). Thus, the EPA finds it more appropriate to base decisions related to whether an AVO inspection frequency is reasonable on the analysis that includes additional travel costs to the site. Based on the information summarized in Table 10, which include additional travel costs, under the single pollutant approach where all costs are assigned to methane and zero cost to VOC, the semiannual, quarterly, and bimonthly (*i.e.*, every other month) frequencies are reasonable for methane emissions; similarly, where all costs are assigned to VOC and zero cost to methane, the semiannual, quarterly, and bimonthly frequencies are reasonable for VOC emissions. Under the multipollutant approach where the costs are divided equally between the two pollutants, all of the frequencies appear reasonable, including monthly monitoring.

The EPA next evaluated the incremental cost associated with advancing to each more frequent monitoring schedule to determine which frequencies would be reasonable for AVO inspections. As shown in Table 10 where additional travel costs are included, the incremental cost of going from semiannual to quarterly inspections is reasonable under both the single pollutant approach (for both methane and VOC individually) and the multipollutant approach. Under the single pollutant approach, the incremental cost of going from quarterly to bimonthly is not reasonable for either methane or VOC emissions. Under the multipollutant approach, the incremental cost of going from quarterly to bimonthly is not reasonable for VOC (\$6,500/ton VOC), which means it is not cost-effective under the multipollutant approach. Therefore, the EPA finds it is not reasonable to require bimonthly AVO inspections.

In summary, the EPA finds that the BSER for single wellhead only well sites is quarterly AVO inspections for indications of potential leaks, with specific attention given to ensuring surface casing valves are closed to prevent the venting of emissions. The EPA is soliciting comment and additional data related to the costs and other potential causes of emissions on a single wellhead that could easily be identified using AVO inspections.

Small well sites. As stated in the November 2021 proposal, the EPA remains mindful about how the fugitive emissions monitoring requirements will affect small businesses. The EPA solicited comment in the November 2021 proposal on regulatory alternatives and additional information that would warrant considering a subset of sites differently based on a potentially different emissions profile, production levels, equipment onsite, or other factors. (86 FR 63173; November 15, 2021). The EPA examined data provided through an information collection request (ICR) distributed in 2016, data provided on equipment/component counts in relation to the October 15, 2018, proposed reconsideration of NSPS OOOOa from independent producers (many of whom are small businesses), data provided through comments on the November 2021 proposal from independent producers, and data contained in the U.S. DOE marginal well study to determine if a subset of well sites with major production and processing equipment should be considered differently.

Consistent with comments received on previous rulemakings, the EPA received comments on the November 2021 proposal requesting consideration of production volumes as a factor when establishing the BSER for well sites.⁶⁷ One commenter stated that the EPA has emphasized component counts instead of considering the significantly more important role that production rates and operating pressure play on the amount

of fugitive emissions.⁶⁸ This commenter then referenced the U.S. DOE marginal well study as showing that most low production well sites (many of which are owned or operated by small businesses) emit less than 3 tpy of methane. However, that marginal well study concludes that the frequency and magnitude of emissions from well sites are more strongly correlated with equipment counts, not production rates.⁶⁹ Further, this study broke down emissions by site size and production levels and found that the smallest emissions rates were from the second production level bin (2 barrels of oil equivalent per day (boe/day) to 6 boe/day) and not the sites with production less than 2 boe/day. Another study issued in April 2022 by Omara, *et al.* concludes that approximately half of the methane emissions emitted from well sites in the U.S. comes from low production well sites (15 boe/day or less production rates).^{70 71} However, the EPA notes that this study is not limited to

⁶⁸ See Document ID No. EPA-HQ-OAR-2021-0317-0814.

⁶⁹ Section 5.2.1 of the study concludes, "The correlation between major equipment counts and site emission frequency (expressed as the number of detected emissions per piece of major equipment, *i.e.*, not absolute count of emissions), was strong with the categorical site 'size' variable and moderate (positive) with the numeric equipment count. Among evaluated numeric variables, site equipment counts also exhibited the strongest associations with both frequency and magnitude of sitewide emissions, exhibiting only a moderate positive correlation with detection frequency and weak associations with whole gas and methane emission rates. Weak correlations were also consistently detected among both the frequency and magnitude of emissions, total oil and gas production, and gas production rates." See Bowers, Richard L. *Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells*. United States. <https://doi.org/10.2172/1865859>. page 19.

⁷⁰ Omara, M., Zavala-Araiza, D., Lyon, D.R. *et al.* Methane emissions from US low production oil and natural gas well sites. *Nat Commun* 13, 2085 (2022). <https://doi.org/10.1038/s41467-022-29709-3>.

⁷¹ The EPA notes that Omara *et al.* analyzed data from offsite measurements of methane emissions from well sites. These measurements would include methane from any leak, venting, flaring, or other source onsite and, therefore, conclusions from this study cannot be directly applied to the specific fugitive sources covered by this action.

⁶⁷ See Document ID Nos. EPA-HQ-OAR-2021-0317-0425 and EPA-HQ-OAR-2021-0317-0814.

fugitive emissions, and the overall impacts on emissions reductions achieved if these rules are finalized as proposed, would target the emissions reported in that study as a whole. Therefore, the EPA does not have compelling information that suggests production levels should provide the basis for consideration of different fugitive emissions requirements for well sites.

While the EPA does not find that production rates correlate to the amount of fugitive emissions and therefore should not be used as a basis for establishing different fugitive emissions monitoring requirements among well sites, we do find that the empirical data described supports distinguishing among well sites based on equipment and component counts. As explained earlier in this section, the EPA utilized model plants, with different equipment and component counts to differentiate fugitive emissions monitoring programs using AVO and OGI through FEAST modeling simulations.

Based on comments received on the October 15, 2018, reconsideration proposal, the EPA has evaluated if certain well sites with major production and processing equipment are more comparable in total component counts to either of the wellhead only model plants. For example, one commenter in 2018 provided average equipment and/or component counts for sites in various states that are owned and operated by independent producers, many of whom are small businesses. These counts included the number of storage vessels, wellheads, and valves, specifically.⁷² That information suggests that there are well sites owned and operated by small businesses that are predominantly composed of single wellheads, with 1 to 2 storage vessels and 11 to 53 valves. These component counts are significantly lower than those estimated for the model plants developed for this supplemental proposal that include major production and processing equipment, which include 127 total valves. This suggests that certain well sites are smaller than our model facilities, and that as a result the model may overstate emissions reductions, and thus cost-effectiveness, for fugitive emissions programs at such small sites. In fact, the EPA anticipates that there are well sites with major production and processing equipment that are of similar component counts as the single wellhead only well site (total components equal to 112, with 23 total valves). Therefore, the EPA does find

that a separate BSER determination is warranted for certain small sites.

The EPA is proposing to define a small well site, for purposes of the fugitive emissions monitoring requirements, as 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. The major production and processing equipment could include a single separator, glycol dehydrator, heater/treater, compressor,⁷³ or uncontrolled storage vessel. It cannot include controlled storage vessels, control devices, or natural gas-driven pneumatic controllers, as those are known to be sources of large emissions events. Further, the equipment allowed at these small sites would not include any affected/designated facilities, nor would it include a CVS which is subject to quarterly OGI monitoring as explained in section IV.K. The EPA is proposing this narrow definition to ensure that sites with leak-prone equipment that requires OGI (or other advanced technology) monitoring are not present at the site. Based on the EPA's analysis of data collected from an ICR distributed in 2016 and applied to the universe of wells operating in 2019, it is estimated that approximately 95,000 well sites would meet this definition (nationwide), or approximately 12 percent of the total nationwide well site count.

Surface casing valves and thief hatches on an uncontrolled storage vessel are the most likely emissions sources for these small well sites. As discussed for single wellhead only well sites, the surface casing valve can easily be identified as open or closed during an AVO inspection and would not require the use of OGI to detect the leak. Similarly, the use of OGI is not necessary to be able to identify if a thief hatch is not closed. For example, the hatch may be fully open, left unlatched and "chattering" with fluctuations from the storage vessel pressures, or have visible indications of liquids such as staining around the hatch. Therefore, the EPA has evaluated AVO inspections to determine the BSER for small well sites.

The EPA utilized the same model results as those provided for single wellhead only well sites. For that model plant, the baseline methane emissions were estimated at 1.27 tpy. In the U.S.

DOE marginal well study, the average methane emissions rate for a thief hatch was 0.20 tpy. Likewise, the emissions factor for tank leaks identified in Rutherford, *et al.* was 0.195 tpy (0.7 kg/day). Therefore, the EPA finds it appropriate to utilize the same model results as those presented in Table 10 for single wellhead only sites to determine the BSER for small well sites. Based on the information presented in Table 10, and our conclusions on the cost-effectiveness of the options for single wellhead only well sites, the EPA proposes quarterly AVO inspections for monitoring fugitive emissions at small well sites.

Additionally, for thief hatches and other openings on storage vessels that are proposed as fugitive emissions components, the EPA is proposing to require an equipment standard as part of the fugitive emissions work practice that requires these thief hatches to remain closed and sealed at all times except during sampling, adding process material, or attended maintenance operations.⁷⁴ This type of equipment standard has been used in other leak detection work practices where open-ended lines and valves are required to be equipped with a closure device (*e.g.*, cap or plug) to seal the open-end of the line or valve, thus preventing leaks from going to the atmosphere. An open thief hatch, even on an uncontrolled storage vessel, would still contribute fugitive emissions and maintaining the thief hatch in a closed position will provide for reduction of emissions at no additional cost. Further, one commenter provided a recommendation that the EPA should propose requirements to maintain thief hatches closed and sealed until the potential emissions from a tank battery exceeds the applicability threshold requiring controls for storage vessels and that AVO monitoring should be used to verify compliance with this standard.⁷⁵ The EPA agrees with this recommendation that AVO inspections would be appropriate to verify compliance with the proposed "closed and sealed" requirement, and therefore, is proposing this requirement for thief hatches that are fugitive emissions components.

Given all of the factors described in this section (fewer equipment, less emissions, many are owned and operated by small businesses, do not contain leak-prone equipment that needs OGI to identify emissions), the

⁷² See Document ID No. EPA-HQ-OAR-2017-0483-1006.

⁷³ The EPA has proposed to exclude compressors located at well sites from being affected facilities because these are generally small compressors that do not have significant emissions. Compressors have been excluded from being affected facilities in NSPS OOOO and NSPS OOOOa as well.

⁷⁴ See section IV.J for solicitation for comment on mechanisms, such as alarms and automatically closing thief hatches that could also provide assurance that thief hatches meet this requirement.

⁷⁵ See Document ID No. EPA-HQ-OAR-2021-0317-0814.

EPA is proposing quarterly AVO surveys and the closed and sealed requirement for thief hatches as the BSE for reducing fugitive emissions at small well sites. The EPA is soliciting comment on this definition for small well sites, including whether additional metrics should be used beyond equipment counts, as well as the proposed standards and requirements for this subcategory of sites.

Multi-wellhead only well sites. For wellhead only well sites with two or more wellheads, the EPA anticipates that the same large emissions source (*i.e.*, surface casing valves) would be present. In addition to these valves on the wellheads, these sites have additional piping, and thus connection points and valves that also present a potential source of fugitive emissions. Emissions from these types of components are generally smaller, and not easily identifiable using AVO.

Further, the estimated component count for the multi-wellhead only well sites is at least double that of the single wellhead only well site (and in many cases much larger), thus, the EPA has determined that additional analysis including OGI monitoring is appropriate. As with the AVO inspection analysis for single wellhead only well sites, the EPA evaluated both a 0.5 percent leak generation rate and a 1.0 percent leak generation rate for this model plant to determine which model results were representative of the fugitive emissions measurement data provided in the same studies used for comparison for single wellhead only well sites analysis.

For multi-wellhead only well sites, the baseline emissions were estimated at 2.66 tpy methane and 4.68 tpy methane at the 0.5 percent and 1.0 percent leak generation rates, respectively. Applying the wellhead emissions range from the

U.S. DOE marginal well study to a site with two wellheads results in baseline methane emissions of 0.52 to 1.12 tpy.⁷⁶ Applying the wellhead emissions from the Rutherford, *et al.* study to a site with two wellheads and meters results in baseline methane emissions of 3.40 tpy. Using the average emissions between these 2 studies, the baseline methane emissions are 2.26 tpy, which is consistent with the 0.5 percent leak generation rate model plant results. Accordingly, the EPA is evaluating the OGI monitoring frequencies based on the modeled results for the 0.5 percent leak generation rate for purposes of this proposal. Additional details of the model results, including those for the 1.0 percent leak generation rate, are included in the Supplemental TSD for this action located at Docket ID No. EPA-HQ-OAR-2021-0317.

TABLE 11—SUMMARY OF EMISSION REDUCTIONS AND COST-EFFECTIVENESS: OGI MONITORING AT WELL SITES WITH TWO OR MORE WELLHEADS

Monitoring frequency	Annual cost (\$/yr/site)	Methane emission reduction (tpy/site)	VOC emission reduction (tpy/site)	Cost-effectiveness		Incremental cost-effectiveness	
				Methane (\$/ton)	VOC (\$/ton)	Methane (\$/ton)	VOC (\$/ton)
Well Sites with Two or More Wellheads: 0.5 Percent Leak Generation Rate Single Pollutant Approach							
Baseline	2.66	0.74
Annual	\$1,972	1.18	0.33	\$1,677	\$6,034
Semiannual	2,327	1.79	0.50	1,300	4,675	\$578	\$2,078
Quarterly	3,037	2.06	0.57	1,473	5,300	2,620	9,425
Bimonthly	3,747	2.15	0.60	1,741	6,263	7,799	28,055
Monthly	5,877	2.24	0.62	2,619	9,420	23,140	83,246
Well Sites with Two or More Wellheads: 0.5 Percent Leak Generation Rate Multipollutant Approach							
Baseline	2.66	0.74
Annual	1,972	1.18	0.33	839	3,017
Semiannual	2,327	1.79	0.50	650	2,338	289	1,039
Quarterly	3,037	2.06	0.57	737	2,650	1,310	4,713
Bimonthly	3,747	2.15	0.60	870	3,131	3,899	14,028
Monthly	5,877	2.24	0.62	1,309	4,710	11,570	41,623

Based on the information summarized in Table 11, under the single pollutant approach where all costs are assigned to methane and zero cost to VOC, all frequencies except monthly appear reasonable for methane emissions; where all costs are assigned to VOC and zero cost to methane, only annual, semiannual, and quarterly monitoring frequencies appear reasonable for VOC emissions. Under the multipollutant approach where the costs are divided equally between the two pollutants, all frequencies appear reasonable when

compared directly to a baseline of no OGI monitoring.

The EPA next evaluated the incremental cost associated with advancing to a more frequent monitoring schedule to determine if those additional costs are reasonable for achieving the additional emissions reductions. Under the single pollutant approach, the incremental cost of going from semiannual to quarterly monitoring for well sites with two or more wellheads is \$2,600/ton methane and \$9,400/ton of VOC. These incremental costs are not reasonable and

are outside the range of costs the EPA has found reasonable for this source category. Under the multipollutant approach, the incremental costs of going from semiannual to quarterly monitoring is \$1,310/ton methane and \$4,713/ton VOC, which is within the range the EPA has found reasonable for this source category.

Next the EPA evaluated whether AVO inspections should also be utilized, in combination with the OGI surveys to allow for faster identification of those larger emissions sources (*i.e.*, surface casing valves) between OGI surveys. As

⁷⁶ The emissions for meters in the U.S. DOE marginal well study were negligible and do not

impact the total average baseline emissions for this type of site.

explained above, fugitive emissions from these large emission sources can be detected through AVO inspections, which are less expensive than OGI. Therefore, the EPA evaluated a combination of semiannual OGI and various frequencies of AVO inspections to determine if this combined program would be as effective as, but less expensive than, quarterly OGI in light of the number and significance of fugitive emissions that can be identified via AVO at this type of well site. The EPA analyzed AVO inspections at quarterly,

bimonthly, and monthly frequencies only because annual or semiannual AVO inspection frequencies would occur at the same time as at least one of the OGI surveys if the EPA were to require OGI monitoring for multi-wellhead only well sites. Further, the EPA determined that some costs associated with the AVO inspections would be less than those provided in Table 9 because those costs are also included in the OGI monitoring costs in Table 8. For example, there would be no additional costs to read the rule, travel

for inspections that overlap with OGI monitoring surveys, or additional recordkeeping system costs. That is, in the evaluation of semiannual OGI with quarterly AVO inspections, only two AVO inspections would be required outside of the OGI surveys, thus the inspection costs would be half what is estimated for quarterly AVO inspections. Table 12 summarizes the results of this combined program for multi-wellhead only well sites.

TABLE 12—SUMMARY OF EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS: COMBINED OGI MONITORING AND AVO INSPECTIONS AT MULTI-WELLHEAD ONLY WELL SITES

Monitoring frequency	Annual cost (\$/yr/site)	Methane emission reduction (tpy/site)	VOC emission reduction (tpy/site)	Cost-effectiveness		Incremental cost-effectiveness	
				Methane (\$/ton)	VOC (\$/ton)	Methane (\$/ton)	VOC (\$/ton)
Multi-Wellhead Well Sites: Includes additional travel costs Single Pollutant Approach							
Semiannual OGI	\$2,327	1.79	0.50	\$1,300	\$4,653
Semiannual OGI + Quarterly AVO	2,651	1.99	0.55	1,331	4,788	\$1,606	\$6,038
Semiannual OGI + Bimonthly AVO	2,973	2.09	0.58	1,425	5,125	3,394	12,210
Semiannual OGI + Monthly AVO	3,671	2.16	0.60	1,822	6,554	12,728	45,787
Multi-Wellhead Well Sites: Includes additional travel costs Multipollutant Approach							
Semiannual OGI	2,327	1.79	0.50	650	2,327
Semiannual OGI + Quarterly AVO	2,651	1.99	0.55	665	2,394	803	3,019
Semiannual OGI + Bimonthly AVO	2,973	2.09	0.58	712	2,563	1,697	6,105
Semiannual OGI + Monthly AVO	3,671	2.16	0.60	911	3,277	6,364	22,893

Under the single pollutant approach, a combined program of semiannual OGI and quarterly or bimonthly AVO are reasonable for methane and VOC emissions individually. However, when incremental costs are considered, the costs of going from quarterly to bimonthly AVO inspections is not reasonable for either pollutant under the single pollutant approach. Under the multipollutant approach, all combinations appear reasonable when evaluated against a baseline of no monitoring. However, the multipollutant incremental costs are not reasonable for a combined program of semiannual OGI and bimonthly AVO because the multipollutant VOC costs exceed the range that the EPA considers reasonable for this source category at \$6,105/ton VOC. Therefore, the EPA finds it is reasonable to consider either quarterly OGI monitoring or a combination of semiannual OGI and quarterly AVO as cost-effective measures to reduce fugitive emissions from multi-wellhead only well sites.

Finally, the EPA compared the emissions reductions and costs associated with the quarterly OGI (most stringent and cost-effective OGI frequency) to the combined program of

semiannual OGI with quarterly AVO inspections. The emissions reductions for these two monitoring programs are comparable (2.06 tpy of methane and 0.57 tpy of VOC for quarterly OGI versus 1.99 tpy of methane and 0.55 tpy of VOC for semiannual OGI with quarterly AVO), but the costs are not. The annual cost of quarterly OGI monitoring is \$3,037, whereas the annual cost of the combined OGI and AVO program is \$2,489. For a combined semiannual OGI and quarterly AVO program the same number of surveys would be conducted at the site (with 2 surveys being OGI with AVO and 2 surveys being AVO only). The EPA is proposing the combined program of semiannual OGI with quarterly AVO as the BSER for multi-wellhead only well sites because of the comparable emissions reductions, same number of total surveys per year, and lower annual costs for the program overall. The EPA solicits comment on this proposed standard, including the basis for the decision to propose semiannual OGI with quarterly AVO inspections rather than quarterly OGI.

Well sites with major production and processing equipment and centralized production facilities. The EPA evaluated a third model plant, which contains

major production and processing equipment. The EPA performed the same analyses to evaluate the BSER for fugitive emissions components at well sites and centralized production facilities with major production and processing equipment as performed for multi-wellhead only well sites. Table 13 summarizes the cost-effectiveness information for each OGI monitoring frequency, and Table 14 summarizes the costs of a combined program using both OGI and AVO.

As discussed for the single wellhead only and multi-wellhead only well site analyses, the EPA modeled OGI monitoring programs for both a 1.0 percent and 0.5 percent leak generation rate and compared the resulting modeled emissions to the same empirical study data to determine which model was more representative of the emissions at this type of well site. The baseline emissions resulting from FEAST for this model plant were 15.40 tpy methane and 8.51 tpy methane at 1.0 percent and 0.5 percent leak generation rate, respectively. The highest average site emissions were calculated at 3.3 tpy methane for large natural gas sites and 4.0 tpy methane for large oil sites in the U.S. DOE marginal

well study, which the EPA anticipates is similar to the model plant with major production and processing equipment. The EPA next applied the emissions factors from the Rutherford, *et al.* study

to the equipment counts in our model plant, resulting in emissions of 7.1 tpy methane. These emissions suggest the 0.5 percent leak generation rate is more appropriate for consideration of the

costs of control and appropriate OGI monitoring frequency for well sites and centralized production facilities with major production and processing equipment.

TABLE 13—SUMMARY OF EMISSION REDUCTIONS AND COST-EFFECTIVENESS: OGI MONITORING AT WELL SITES WITH MAJOR PRODUCTION OR PROCESSING EQUIPMENT

Monitoring frequency	Annual cost (\$/yr/site)	Methane emission reduction (tpy/site)	VOC emission reduction (tpy/site)	Cost-effectiveness		Incremental cost-effectiveness	
				Methane (\$/ton)	VOC (\$/ton)	Methane (\$/ton)	VOC (\$/ton)
Well Sites and Centralized Production Facilities: 0.5 percent leak generation rate Single Pollutant Approach							
Baseline	8.51	2.37
Annual	\$2,162	3.99	1.11	\$542	\$1,951
Semiannual	2,588	5.73	1.59	452	1,624	\$244	\$879
Quarterly	3,440	6.61	1.84	520	1,872	969	3,487
Bimonthly	4,292	6.97	1.94	616	2,217	2,398	8,625
Monthly	6,848	7.26	2.02	943	3,393	8,676	31,212
Well Sites and Centralized Production Facilities: 0.5 percent leak generation rate Multipollutant Approach							
Baseline	8.51	2.37
Annual	2,162	3.99	1.11	271	975
Semiannual	2,588	5.73	1.59	226	812	122	439
Quarterly	3,440	6.61	1.84	260	936	485	1,744
Bimonthly	4,292	6.97	1.94	308	1,108	1,199	4,313
Monthly	6,848	7.26	2.02	472	1,697	4,338	15,606

Based on the information summarized in Table 13 for the 0.5 percent leak generation rate, under the single pollutant approach where all costs are assigned to methane and zero cost to VOC, all frequencies appear reasonable for methane emissions; where all costs are assigned to VOC and zero cost to methane, all frequencies appear reasonable for VOC emissions. Similarly, under the multipollutant approach where the costs are divided equally between the two pollutants, all frequencies appear reasonable when compared directly to a baseline of no OGI monitoring.

The EPA next evaluated the incremental cost associated with advancing to each more frequent monitoring schedule. As shown in Table 13 for the single pollutant approach, the incremental costs of going from quarterly to bimonthly monitoring for these larger well sites are \$2,398/ton methane and \$8,625/ton of VOC. These

incremental costs are outside the range of costs the EPA has found reasonable for this source category (*i.e.*, \$2,165/ton methane and \$5,540/ton VOC). Under the multipollutant approach, the incremental costs of going from quarterly to bimonthly monitoring are \$1,199/ton methane and \$4,313/ton VOC, which is within the range the EPA has found reasonable for this source category.

Next the EPA evaluated the costs of a combined program for well sites and centralized production facilities, using quarterly OGI as a baseline with AVO inspections added at bimonthly, and monthly frequencies to determine if this combined program would be as effective as, but less expensive than, bimonthly OGI. The EPA did not evaluate annual, semiannual, or quarterly AVO inspection frequencies because those would occur at the same time as at least one of the OGI surveys if the EPA were to require quarterly OGI monitoring for

well sites and centralized production facilities with major production and processing equipment. However, the EPA is soliciting comment on the costs and effectiveness of a combined program of quarterly OGI surveys in combination with quarterly AVO inspections that are offset by one month, such that eight total fugitive surveys would take place over the course of a year. Further, the EPA determined that some costs associated with the AVO inspections would be less than those provided in Table 9 because those costs are also included in the OGI monitoring costs in Table 8. For example, there would be no additional costs to read the rule, travel for inspections that overlap with OGI monitoring surveys, or additional recordkeeping system costs. Table 14 summarizes the results of this combined program for well sites and centralized production facilities with major production and processing equipment.

TABLE 14—SUMMARY OF EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS: COMBINED OGI MONITORING AND AVO INSPECTIONS AT WELL SITES AND CENTRALIZED PRODUCTION FACILITIES

Monitoring frequency	Annual cost (\$/yr/site)	Methane emission reduction (tpy/site)	VOC emission reduction (tpy/site)	Cost-effectiveness		Incremental cost-effectiveness	
				Methane (\$/ton)	VOC (\$/ton)	Methane (\$/ton)	VOC (\$/ton)
Well Sites and Centralized Production Facilities: Assumes no additional travel costs Single Pollutant Approach							
Quarterly OGI	\$3,440	6.61	1.84	\$520	\$1,872

TABLE 14—SUMMARY OF EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS: COMBINED OGI MONITORING AND AVO INSPECTIONS AT WELL SITES AND CENTRALIZED PRODUCTION FACILITIES—Continued

Monitoring frequency	Annual cost (\$/yr/site)	Methane emission reduction (tpy/site)	VOC emission reduction (tpy/site)	Cost-effectiveness		Incremental cost-effectiveness	
				Methane (\$/ton)	VOC (\$/ton)	Methane (\$/ton)	VOC (\$/ton)
OGI + Bimonthly AVO	4,232	6.93	1.93	611	2,198	2,497	8,981
OGI + Monthly AVO	5,021	7.10	1.97	707	2,545	4,616	16,608
Well Sites and Centralized Production Facilities: Assumes no additional travel costs Multipollutant Approach							
Quarterly OGI	3,440	6.61	1.84	260	936
OGI + Bimonthly AVO	4,232	6.93	1.93	305	1,099	1,248	4,491
OGI + Monthly AVO	5,021	7.10	1.97	354	1,272	2,308	8,304

Under the single pollutant approach, a combined program of quarterly OGI and bimonthly or monthly AVO are reasonable for methane and VOC emissions individually. When incremental costs are considered, the costs of going from bimonthly to monthly AVO inspections is not reasonable for either pollutant under the single pollutant approach. Under the multipollutant approach, all combinations appear reasonable when evaluated against a baseline of no monitoring. The multipollutant incremental costs are not reasonable for a combined program of quarterly OGI and monthly AVO. However, the EPA finds it is reasonable to consider either a bimonthly OGI monitoring program alone or a combination of quarterly OGI and bimonthly AVO as cost-effective measures to reduce fugitive emissions from well sites and centralized production facilities that include major production and processing equipment.

Finally, the EPA compared the emissions reductions achieved by the combined quarterly OGI and bimonthly AVO program to a bimonthly OGI program with no AVO inspections. While both programs appear cost-effective, the combined program achieves comparable emissions reductions to the bimonthly OGI program (6.93 tpy of methane and 1.93 tpy of VOC for the combined program, compared to 6.97 tpy of methane and 1.94 tpy of VOC for the bimonthly OGI program) at a comparable cost (\$4,232 for the combined program compared to \$4,292 for the bimonthly OGI program), and results in more total visits to the well site or centralized production facility. Specifically, a total of four OGI surveys and four AVO inspections would be completed, for a total of eight surveys at the site each year (two of the bimonthly AVO inspections would occur at the same time as two of the OGI surveys) whereas bimonthly OGI would result in six surveys of the site each

year. Additional visits to the site create more opportunities to find and fix fugitive emissions, including the large emissions that can be detected by AVO inspections. Therefore, the EPA finds that the BSER for well sites and centralized production facilities with major production and processing equipment is quarterly OGI surveys combined with bimonthly AVO inspections and therefore is proposing this combined program as the standard for reducing fugitive emissions at these sites. The EPA solicits comment on this proposed standard, including the basis for the decision to propose quarterly OGI monitoring with bimonthly AVO inspections rather than bimonthly OGI monitoring.

Because the EPA finds that the combination of quarterly OGI monitoring and bimonthly AVO inspections are reasonable, the EPA is proposing this combination of monitoring frequencies and methods as the BSER for well sites and centralized production facilities with major production and processing equipment. The EPA is specifically proposing to require this combination program for fugitive emissions components affected facilities located at well sites or centralized production facilities that contain the following major production and processing equipment:

- One or more controlled storage vessels or tank batteries,
- One or more control devices,
- One or more natural gas-driven pneumatic controllers or natural gas-driven pneumatic pumps, or
- Two or more pieces of major production and processing equipment not otherwise specified.⁷⁷

The EPA is proposing to define this subcategory as well sites with one or more controlled storage vessels, control

⁷⁷ Major production and processing equipment includes centrifugal and reciprocating compressors, separators, glycol dehydrators, heater/treaters, and storage vessels.

devices, or natural gas-driven pneumatic controllers because those sources individually are known sources of super-emitter emissions events (see section IV.C) and are subject to quarterly OGI for compliance assurance (storage vessels and pneumatic controllers) or are subject to other continuous monitoring requirements (control devices). Further, the EPA is defining this subcategory as well sites with two or more other major production and processing equipment because the model plant includes two separators, which are another source that can contribute to large emissions when combined with a storage tank. As explained previously related to small well sites, the EPA is proposing an additional subcategory of well sites to recognize that this model plant may overstate the fugitive emissions from well sites that have only one piece of major production and processing equipment that is not a controlled storage vessel, control device, pneumatic controller, or pneumatic pump. Consistent with comments received on the November 2021 proposal, the EPA understands that the industry is aware that this specific equipment (controlled storage vessels, control devices, and natural gas-driven pneumatic controllers) is more prone to emissions and that fugitive surveys using OGI present an opportunity to identify these emissions. However, the EPA is not expanding the definition of fugitive emissions component to include controlled tank batteries, control devices, or natural gas-driven pneumatic controllers as explained earlier in this section because those sources are subject to separate requirements that are intended to ensure proper operation (including regular inspections, in the case of controlled tank batteries and natural gas-driven pneumatic controllers).

In summary, the EPA is proposing that the BSER for well sites with major

production and processing equipment and centralized production facilities, is a combination program consisting of bimonthly AVO inspections and quarterly OGI monitoring and the closed and sealed requirement for thief hatches (as explained in the discussion on small well sites).

Well closure plans. The EPA is proposing that owners and operators of each well site or centralized production facility may stop the required fugitive emissions monitoring and repair for that site when the well site has been properly closed because in that event there should not be any equipment or other fugitive components onsite for monitoring. This would also help address concerns cited by many stakeholders regarding continuing emissions from orphaned wells and unplugged idled wells. In the November 2021 proposal, the EPA solicited comment and information on idled and unplugged wells due to the EPA's understanding and concern that these non-producing oil and natural gas wells are generally unmanned and many are in disrepair. 86 FR 63240 (November 15, 2021). The EPA notes that "some states and NGOs also have elevated concerns about the potential number of wells that could be abandoned in the near future as they reach the end of their productive lives." *Id.*

In addition, since promulgation of NSPS OOOOa, the EPA has received various questions from owners and operators related to when fugitive emissions monitoring applies if a well is shut-in, idled, or permanently closed. The Agency is therefore proposing specific requirements in NSPS OOOOb to ensure clarity for well sites and centralized production facilities subject to the rule. Studies have shown that idled wells can have fugitive emissions, and in some cases these emissions can be very large.^{78 79} The EPA finds that these data demonstrate the importance of continued fugitive emissions monitoring on a routine basis to ensure that fugitive emissions continue to be addressed throughout the life of the well site, even during periods when the wells at the site are shut-in or idled and could

be put back into production at a later date.

However, there is a point at the end of a well site's useful life where the EPA does anticipate the cessation of fugitive emissions monitoring is appropriate, when all wells at the well site have been permanently plugged and all equipment has been removed. To demonstrate that a well site has reached that point where it is appropriate to cease fugitive monitoring, the EPA is proposing to require owners and operators to develop and submit a well closure plan within 30 days of the cessation of production from all wells at the well site or centralized production facility. The plan would include: (1) The steps necessary to close all wells at the well site, including plugging of all wells; (2) the financial requirements and disclosure of financial assurance to complete closure; and (3) the schedule for completing all activities in the closure plan. The EPA is also proposing to require that owners and operators submit a notification to the Agency 60 days before beginning well closure activities. The EPA solicits comment on additional provisions that could be added, including, for example, automatic consequences for missed monitoring reports, as a means of assuring that companies remain engaged with the site, including conducting monitoring, until all the wells at the site are properly closed.

Finally, the EPA is proposing that when the well closure activities have been completed, prior to ceasing regular monitoring, the owner or operator would be required to conduct a survey of the well site using OGI. The purpose of this survey is to ensure there are no emissions identified with OGI. If any emissions are identified, the owner or operator would be required to take steps to eliminate those emissions and resurvey. The EPA is proposing that once the OGI survey indicates no emissions are present, the well site would be considered closed and no further fugitive emissions monitoring would be required.

The EPA finds that the requirements described above not only would allow owners and operators of well sites and centralized production facilities to stop fugitive emissions monitoring at a clearly defined point where fugitive emissions are no longer a concern at the site, these proposed requirements would also prevent well sites from becoming orphaned or left in an idled and unplugged state with no form of emissions monitoring and repair. The EPA assesses the continued monitoring of well sites will help identify emissions and maintain the well site such that it does not fall into disrepair. The EPA is

soliciting comment on these planning and monitoring requirements. Lastly, because a well site could have a long useful life, during which there may be different owners or operators, the EPA is proposing to require owners and operators to report, through the annual report, any changes in ownership at individual well sites so that it is clear who the responsible owners and operators are until the site is plugged and closed and fugitive emissions monitoring is no longer required. We propose this reporting requirement as an important step in maintaining transparency for the responsible owner or operator and will also prevent well sites from becoming orphaned in the future. The EPA solicits comment on this additional reporting requirement, including other mechanisms for obtaining this information.

iii. Summary of Proposed Standards

Definition of fugitive emissions component. Based on changes made and discussed under section IV.A.1.a.ii of this preamble, the EPA is proposing to define fugitive emissions component as any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and CVS not subject to 40 CFR 60.5411b, thief hatches or other openings on a storage vessel not subject to 40 CFR 60.5395b, compressors, instruments, meters, and yard piping.

Monitoring requirements. The EPA is proposing the following requirements for each subcategory of well sites not located on the Alaska North Slope.

- Single wellhead only well sites and small well sites: Quarterly AVO inspections.
- Multi-wellhead only well sites: Semiannual OGI (or EPA Method 21) monitoring and quarterly AVO inspections at wellhead only well sites with two or more wellheads.
- Well sites with major production and processing equipment and centralized production facilities: Quarterly OGI (or EPA Method 21) monitoring and bimonthly AVO inspections at well sites and centralized production facilities with: (1) One or more controlled storage vessels or tank batteries; (2) one or more control devices; (3) one or more natural gas-driven pneumatic controllers; or (4) two or more pieces of major production or processing equipment not listed in items (1) through (3).

Where semiannual monitoring is proposed, subsequent semiannual

⁷⁸ Amy Townsend-Small and Jacob Hoschouer. "Direct measurements from shut-in and other abandoned wells in the Permian Basin of Texas indicate some wells are a major source of methane emissions and produced water." 2021 *Environ. Res. Lett.* 16 054081. <https://iopscience.iop.org/article/10.1088/1748-9326/abf06f>.

⁷⁹ Eric D. Lebel, Harmony S. Lu, Lisa Vielstädte, Mary Kang, Peter Banner, Marc L. Fischer, and Robert B. Jackson. "Methane Emissions from Abandoned Oil and Gas Wells in California." *Environmental Science & Technology* 2020 54 (22), 14617–14626. DOI: 10.1021/acs.est.0c05279.

monitoring would occur at least 4 months apart and no more than 7 months apart. Where quarterly monitoring is proposed, subsequent quarterly monitoring would occur at least 60 days apart and quarterly monitoring may be waived when temperatures are below 0 degrees Fahrenheit (°F) for two of three consecutive calendar months of a quarterly monitoring period.

When fugitive emissions are identified through AVO inspections, the EPA is proposing to require that repairs be completed within 15 days after the first attempt. The EPA is proposing a 15-day repair timeframe so that the monthly AVO inspections do not overlap the repair schedule. When fugitive emissions are identified through OGI surveys, the EPA is proposing to require a first attempt at repair within 30 days of detecting the fugitive emissions, with final repair, including resurvey to verify repair, completed within 30 days after the first attempt, consistent with the November 2021 proposal. Finally, we are proposing to require owners and operators to develop a fugitive emissions monitoring plan that covers all the applicable requirements for the fugitive emissions components located at a well site or centralized production facility. This monitoring plan would also include specific procedures, defined by the owner or operator, to ensure consistency in surveys conducted with either OGI or EPA Method 21, and to ensure that these surveys are conducted appropriately for identifying fugitive emissions from components at the site.

Monitoring (AVO and OGI) surveys would be required to continue until the owner or operator permanently closes the well site. Closure includes completing well closure activities specified by the owner or operator in a well closure plan. A final OGI survey of the well site would be required to ensure there are no emissions following plugging all of the wells at the site and completing closure activities. If emissions are identified during this OGI survey, the rule would require eliminating those emissions within the same timeline as required for regular OGI surveys (first attempt within 30 days of identification, with final repair within 30 days of the first attempt) and a resurvey of the whole site to verify emissions have been addressed.

Recordkeeping and Reporting Requirements. Specific recordkeeping and reporting requirements would also apply for each fugitive emissions affected facility. Sources would be required to report the designation of the type of site (*i.e.*, well site, centralized

production facility, or compressor station) at which the fugitive emissions components affected facility is located. In addition, for each fugitive emissions components affected facility that becomes an affected facility during the reporting period, the date of the startup of production or the date of the first day of production after modification would be required for well sites or centralized production facility. Each fugitive emissions components affected facility at a well site would also be required to specify in the annual report what type of site it is (*i.e.*, a single wellhead only well site, small well site, a multi-wellhead only well site, or a well site with major production and processing equipment).

For fugitive emissions components affected facilities complying with the requirement to conduct surveys using AVO, the annual report would require the date of the survey, the total number and type of equipment for which leaks were identified, or, if no leaks were detected, a statement that there were no leaks on the day of inspection, the total number and type of equipment for which leaks identified were repaired within 15 calendar days, the total number and type of equipment for which no repair attempt was made within 15 days of the leaks being identified, and the total number and type of equipment placed on the delay of repair.

For fugitive emissions components affected facilities complying with the requirement to monitor for fugitive emissions using OGI on a semiannual or quarterly basis, the following information would be required to be included in the annual report:

- Date of the survey,
- Monitoring instrument used,
- Any deviations from key monitoring plan elements or a statement that there were no deviations from these elements of the monitoring plan,
- Number and type of components for which fugitive emissions were detected,
- Number and type of fugitive emissions components that were not repaired,
- Number and type of fugitive emission components (including designation as difficult-to-monitor or unsafe-to-monitor, if applicable) on delay of repair and explanation for each delay of repair, and
- Date of planned shutdown(s) that occurred during the reporting period if there are any components that have been placed on delay of repair.

b. EG OOOOc

In section XII.A.2 of the November 2021 proposal preamble (86 FR 63196;

November 15, 2021), the EPA proposed BSER for EG OOOOc for reducing methane emissions from existing well sites that was the same as that proposed for new well sites, with a site-wide emissions threshold used to determine OGI monitoring frequency. However, as explained for new, modified, and reconstructed well sites and centralized production facilities in the previous section, the EPA has changed approaches for evaluating the BSER for fugitive emissions components, which also affects the determinations for BSER for existing sources under EG OOOOc.

The EPA did not identify any factors specific to existing sources that would alter the analysis performed for new sources to make that analysis different for existing well sites. Therefore, the EPA has evaluated the presumptive standards in EG OOOOc using the same approach as that for the proposed standards in NSPS OOOOb, specifically evaluating both the total cost-effectiveness of each monitoring option against a baseline of no monitoring and the incremental costs of increasing stringency between monitoring options. The EPA has determined that the methods for identifying fugitive emissions (*i.e.*, AVO, OGI, and EPA Method 21), methane emissions reductions, costs, and cost effectiveness related to the single pollutant approach for methane emissions discussed above for the fugitive emissions components affected facility at new well sites are also applicable for the fugitive emissions components affected facility at existing well sites. Further, the fugitive emissions requirements do not require the installation of controls on existing equipment or the retrofit of equipment, which can generally be an additional factor for consideration when determining the BSER for existing sources. Therefore, the EPA is proposing that it is appropriate to use the analysis developed for the proposed NSPS OOOOb to also determine the BSER and proposed presumptive standards for the EG OOOOc. Additionally, the EPA is proposing the same requirement that thief hatches must be closed and sealed at all times, in addition to the requiring fugitive emissions monitoring continue until all of the wells at an existing well site or centralized production facility are permanently closed and the owner or operator has completed the same requirements for well closure and submitted a well closure report meeting the same requirements described for new sources.

Single wellhead only and small well sites. Table 15 summarizes the costs associated with AVO inspections at existing single wellhead only well sites

and existing small well sites. Based on the information summarized in Table 15, and the explanation provided for new single wellhead only well sites and new small well sites, the semiannual, quarterly, and bimonthly inspection frequencies are all reasonable. When

examining the incremental costs of going from quarterly to bimonthly AVO inspections, the costs are not reasonable at \$3,618/ton methane. Therefore, the EPA proposes that the BSER for existing single wellhead only well sites is quarterly AVO inspections, and the

BSER for existing small sites includes quarterly AVO inspections and the closed and sealed requirement for thief hatches (as explained in the discussion above on new, modified and reconstructed small well sites).

TABLE 15—SUMMARY OF METHANE EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS: AVO INSPECTIONS AT EXISTING SINGLE WELLHEAD ONLY WELL SITES AND SMALL WELL SITES

Monitoring frequency	Annual cost (\$/yr/site)	Methane emission reduction (tpy/site)	Total cost-effectiveness (\$/ton methane)	Incremental cost-effectiveness (\$/ton methane)
Annual	\$296	0.11	\$2,579
Semiannual	417	0.40	1,048	429
Quarterly	660	0.56	1,181	1,511
Bimonthly	904	0.63	1,443	3,618
Monthly	1,633	0.69	2,367	11,455

Multi-wellhead only well sites. Table 16 summarizes the costs associated with OGI monitoring at multi-wellhead only well sites and Table 17 summarizes the costs associated with combined OGI and AVO surveys at multi-wellhead only well sites. Based on the information summarized in Table 16, the costs of annual, semiannual, quarterly, and bimonthly OGI monitoring is reasonable when compared to a baseline of no monitoring. When examining the incremental costs of going from semiannual OGI to quarterly OGI, the

costs are not reasonable at \$2,620/ton methane reduced. The EPA next evaluated the costs associated with adding AVO inspections to semiannual OGI monitoring to determine if additional emission reductions could be achieved at a reasonable cost. Based on the information summarized in Table 17, all programs presented are cost-effective when compared to a baseline of no monitoring. When examining the incremental costs of going from a combined program of semiannual OGI with quarterly AVO inspections to one

with bimonthly AVO inspections, the costs are not reasonable at \$3,394/ton methane reduced. Because the combined program of semiannual OGI with quarterly AVO inspections is cost-effective and would result in more visits to the well site, and thus provide opportunity to address any emissions detected, the EPA is proposing that the BSER for existing multi-wellhead only well sites is a combined program of semiannual OGI with quarterly AVO inspections.

TABLE 16—SUMMARY OF EMISSION REDUCTIONS AND COST-EFFECTIVENESS: OGI MONITORING AT WELL SITES WITH TWO OR MORE WELLHEADS

Monitoring frequency	Annual cost (\$/yr/site)	Methane emission reduction (tpy/site)	Total cost-effectiveness methane (\$/ton)	Incremental cost-effectiveness methane (\$/ton)
Baseline	2.66
Annual	\$1,972	1.18	\$1,677
Semiannual	2,327	1.79	1,300	578
Quarterly	3,037	2.06	1,473	2,620
Bimonthly	3,747	2.15	1,741	7,799
Monthly	5,877	2.24	2,619	23,140

TABLE 17—SUMMARY OF METHANE EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS: COMBINED OGI MONITORING AND AVO INSPECTIONS AT EXISTING MULTI-WELLHEAD ONLY WELL SITES

Monitoring frequency	Annual cost (\$/yr/site)	Methane emission reduction (tpy/site)	Total cost-effectiveness methane (\$/ton)	Incremental cost-effectiveness methane (\$/ton)
Semiannual OGI	\$2,327	1.79	\$1,300
OGI + Quarterly AVO	2,651	1.99	1,331	\$1,606
OGI + Bimonthly AVO	2,973	2.09	1,425	3,394
OGI + Monthly AVO	3,671	2.16	1,822	12,728

Well sites with major production and processing equipment and centralized production facilities. Table 18 summarizes the costs associated with

OGI monitoring and Table 19 summarizes the costs of combined OGI and AVO surveys at existing well sites and centralized production facilities

with major production and processing equipment. The EPA is proposing the same definition for these well sites, including the specific equipment that

constitutes a well site in this subcategory (*e.g.*, leak-prone equipment, such as controlled storage vessels). Based on the information summarized in Table 18, all monitoring frequencies appear cost-effective when compared to a baseline of no monitoring. When incremental costs are considered, the costs of going from quarterly to bimonthly OGI monitoring is not reasonable. The EPA then evaluated if AVO inspections could be added to the

quarterly OGI monitoring at a reasonable cost. As shown in Table 19, all programs presented are cost-effective when compared to a baseline of no monitoring. When examining the incremental costs of going from a quarterly OGI program to a combined program of quarterly OGI with bimonthly AVO inspections, the costs are not reasonable at \$2,497/ton methane reduced. Therefore, the EPA is proposing quarterly OGI monitoring for

these sites. In sum, the EPA is proposing that the BSER for existing well sites with major production and processing equipment and centralized production facilities consists of quarterly OGI monitoring and the closed and sealed requirement for thief hatches (as explained above in the discussion on new, modified or reconstructed small well sites).

TABLE 18—SUMMARY OF EMISSION REDUCTIONS AND COST-EFFECTIVENESS: OGI MONITORING AT WELL SITES WITH MAJOR PRODUCTION OR PROCESSING EQUIPMENT

Monitoring frequency	Annual cost (\$/yr/site)	Methane emission reduction (tpy/site)	Total cost-effectiveness methane (\$/ton)	Incremental cost-effectiveness methane (\$/ton)
Baseline	8.51
Annual	\$2,162	3.99	\$542
Semiannual	2,588	5.73	452	\$244
Quarterly	3,440	6.61	520	969
Bimonthly	4,292	6.97	616	2,398
Monthly	6,848	7.26	943	8,676

TABLE 19—SUMMARY OF METHANE EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS: COMBINED OGI MONITORING AND AVO INSPECTIONS AT EXISTING WELL SITES WITH MAJOR PRODUCTION AND PROCESSING EQUIPMENT AND CENTRALIZED PRODUCTION FACILITIES

Monitoring frequency	Annual cost (\$/yr/site)	Methane emission reduction (tpy/site)	Total cost-effectiveness methane (\$/ton)	Incremental cost-effectiveness methane (\$/ton)
Quarterly OGI	\$3,440	6.61	\$520
OGI + Bimonthly AVO	4,232	6.93	611	\$2,497
OGI + Monthly AVO	5,021	7.10	707	4,616

2. OGI Monitoring at Compressor Stations

a. NSPS OOOOb

In the November 2021 proposal, the EPA proposed that compressor stations would be required to conduct quarterly OGI or EPA Method 21 monitoring. Where OGI monitoring was used to perform the quarterly monitoring surveys, the EPA proposed surveys would be conducted according to the procedures proposed in the November 2021 proposal as appendix K.

In this supplemental proposal, the EPA is retaining the proposed quarterly OGI (or EPA Method 21) monitoring requirement for fugitive emissions components affected facilities located at compressor stations (including the requirement that consecutive quarterly monitoring survey be conducted at least 60 days apart). Also, as in the November 2021 proposal, the supplemental proposal includes the provision in the 2016 NSPS OOOOa that the quarterly monitoring may be waived when temperatures are below 0 °F for two of

three consecutive calendar months of a quarterly monitoring period.

In addition, the EPA is proposing to add a requirement to conduct monthly AVO monitoring at compressor stations. As discussed above for well sites, the EPA finds these AVO monitoring requirements can be conducted by any personnel at the site as indications of emissions can be identified without the need for specialized training. Any indications of fugitive emissions identified via AVO would be subject to repair. The EPA specifically received comments on the November 2021 proposal that indicated that “even though small company compressor stations are not manned 24 hours a day, they are visited weekly, if not daily.”⁸⁰ Therefore, no additional costs are associated with the proposed monthly AVO inspection requirement for compressor stations.

While the EPA is maintaining (and strengthening in the case of the monthly

AVO requirement) the November 2021 proposal as it relates to the collection of fugitive emissions components located at compressor stations, the EPA is not including the requirement to conduct OGI monitoring surveys according to the procedures that would become appendix K. See discussion in section IV.A.1.a.ii on comments received opposing this requirement. Instead, the EPA is proposing that quarterly surveys be performed according to the OGI procedures specified in the proposed regulatory text in NSPS OOOOb or according to EPA Method 21.

b. EG OOOOc

Based on the analysis presented in section XII.A.2 of the 2021 November proposal preamble (86 FR 63196; November 15, 2021), the proposed BSER for EG OOOOc for reducing methane emissions from existing compressor stations was quarterly monitoring (using either OGI or EPA Method 21).

Based on the same public comment considerations and reasoning as explained above (see sections IV.A.2.a.ii

⁸⁰ See Document ID Nos. EPA-HQ-OAR-2021-0317-0585 and EPA-HQ-OAR-2021-0317-0814.

of this preamble) for changes to the proposed NSPS OOOOb for fugitive emissions at compressor stations, the EPA is proposing the same changes and requirements under EG OOOOc. The EPA did not identify any factors specific to existing sources that would alter the analysis performed for new sources to make that analysis different for existing compressor stations. The EPA determined that the methods for identifying fugitive emissions (*i.e.*, AVO, OGI, and EPA Method 21), methane emission reductions, costs, and cost effectiveness discussed above for the fugitive emissions components affected facility at new compressor stations are also applicable for the fugitive emissions components affected facility at existing compressor stations. The fugitive emissions requirements do not require the installation of controls on existing equipment or the retrofit of equipment, which can generally be an additional factor for consideration when determining the BSER for existing sources. Therefore, the EPA found it is appropriate to continue using the analysis developed for the proposed NSPS OOOOb to also determine the BSER and proposed presumptive standards for the EG OOOOc.

3. OGI Monitoring at Well Sites and Compressor Stations on the Alaska North Slope

a. NSPS OOOOb

In the November 2021 proposal, the EPA proposed an annual monitoring requirement for well sites and compressor stations located on the Alaska North Slope, which included a requirement to follow the procedures outlined in the proposed appendix K where monitoring was conducted using OGI.

In this supplemental proposal, the EPA is retaining the proposed annual monitoring requirement for well sites and compressor stations located on the Alaska North Slope. Consecutive annual monitoring surveys would be required at least 9 months apart and no more than 13 months apart. For the reasons discussed in section IV.A.1.a.ii, the EPA is not including the requirement to follow the proposed procedures in appendix K when conducting monitoring surveys with OGI. The EPA is proposing that annual surveys be performed according to the OGI procedures specified in the proposed regulatory text in NSPS OOOOb or according to EPA Method 21 of appendix A–7 of this part.

b. EG OOOOc

Based on the analysis presented in section XII.A.2 of the November 2021 proposal preamble (86 FR 63196; November 15, 2021), the proposed BSER for EG OOOOc for reducing methane emissions from existing well sites and compressor stations located on the Alaska North Slope was annual monitoring.

In this supplemental proposal, the EPA is retaining the annual monitoring requirement for existing well sites and compressor stations located on the Alaska North Slope. As discussed in the November 2021 proposal, the same technical infeasibility issues with weather conditions exist for existing well sites and compressor stations located on the Alaska North Slope as for new well sites and compressor stations. Further, the EPA did not identify any other factors specific to existing sources located on the Alaska North Slope that would alter the analysis performed for new sources to make that analysis different for existing well sites and compressor stations. Therefore, the EPA is proposing a presumptive standard for reducing methane emissions from the fugitive emissions components designated facilities located at existing well sites and compressor stations located on the Alaska North Slope that is the same as what we are proposing for NSPS OOOOb.

B. Advanced Methane Detection Technologies

As discussed in section XI.A.5 of the November 2021 proposal preamble (86 FR 63175; November 15, 2021), the EPA proposed an alternative screening option that would allow the use of advanced measurement technologies as an alternative to the use of ground based OGI surveys and AVO inspections to identify emissions from the collection of fugitive emissions components located at well sites, centralized production facilities, and compressor stations. In the November 2021 proposal, the EPA stated that we did not have enough information to determine how the proposed alternative standard (*i.e.*, bimonthly screening using advanced measurement technologies) compared to the proposed BSER of OGI monitoring in that notice. Further we stated that information provided through comments to the November 2021 proposal may be used to reevaluate BSER for fugitive emissions components at well sites and compressor stations through a supplemental proposal.⁸¹ As described below, commenters

overwhelmingly supported the concept of an alternative screening option that would allow owners and operators to take advantage of advanced measurement technologies to detect fugitive emissions. Commenters also provided helpful information and input on how the alternative screening option could be made more useful and effective, including flexibilities that could be incorporated into the program design to enable the use of a wider variety of advanced measurement technologies. While there was widespread support of the concept of an alternative screening option, the EPA still does not have enough information to conduct the requisite BSER analysis⁸² for any specific advanced measurement technology to determine whether it would qualify as the BSER for detecting fugitive emissions (either in lieu of or in addition to OGI). The EPA, however, does anticipate that through this alternative screening option, if finalized as proposed and utilized by the industry, the Agency would gain additional information that could be used to reevaluate the BSER in a future rulemaking.

In response to this feedback, the EPA is proposing a number of changes to the alternative screening option that are intended to support the deployment and utilization of a broader spectrum of advanced measurement technologies and, ultimately, enable more cost-effective reductions in emissions. These changes include a proposed “matrix” which would specify several different screening frequencies corresponding to a range of minimum detection levels, in contrast to the single screening frequency and detection level permitted under the November 2021 proposal. In addition, we are proposing to allow owners and operators the option of using continuous monitoring technologies as an alternative to periodic screening and are proposing long- and short-term emissions rate thresholds that would trigger corrective action as well as monitoring plan requirements for owners and operators that choose this approach.

Lastly, we are proposing to establish a clear and streamlined pathway for technology developers and other entities to seek the EPA’s approval for the use of advanced measurement technologies under this alternative screening option. Under this pathway, entities would seek approval for alternative test methods to demonstrate the performance of

⁸² Please see CAA section 111(a)(1) for a list of factors, including costs, that the EPA must take into account when determining whether an emission reduction system would qualify as the BSER.

⁸¹ 86 FR 63177 (November 15, 2021).

alternative technologies, which would replace the use of OGI and AVO for fugitive emissions monitoring and the use of OGI for no identifiable emissions monitoring of covers and CVS (see section IV.K of this preamble) in both the proposed NSPS OOOOb and EG OOOOc. Once an alternative test method is approved by the EPA according to the proposed process, which is described in more detail below in Section IV.B.3, owners and operators would be able to utilize the advanced methane detection technology/technique in accordance with the alternative test method without the need for additional approval. Section IV.B.1 of this preamble discusses the use of advanced measurement technology in an alternative periodic screening approach. Section IV.B.2 of this preamble discusses the use of advanced measurement technologies in a continuous monitoring approach as a second alternative approach to the fugitive emissions monitoring and repair program and no identifiable emissions monitoring of covers and CVS in NSPS OOOOb and EG OOOOc. Section IV.B.3 of this preamble discusses the requirements for applying for an alternative test method, including who can submit an application for an alternative test method. Once an alternative test method is approved by the EPA, owners and operators would be able to utilize the advanced methane detection technology/technique in accordance with the alternative test method without the need for additional approval.

1. Alternative Periodic Screening

a. Summary of November 2021 Proposal

The EPA proposed an alternative fugitive emissions monitoring and repair program for new, modified, or reconstructed fugitive emissions sources (*i.e.*, collection of fugitive emissions components located at well sites, centralized production facilities, and compressor stations) that included bimonthly screening for large emissions events using advanced measurement technologies coupled with ground based OGI monitoring at least annually at each site. Specifically, the EPA proposed to allow owners and operators to comply with this alternative fugitive emissions standard instead of the ground-based quarterly or (co-proposed) semiannual OGI surveys for regulated sources, so long as owners and operators chose this alternative for all affected well sites, centralized production facilities, and compressor stations within a company-defined area and the methane detection technology used for the bimonthly

screening surveys had a demonstrated minimum detection threshold of 10 kg/hr.

In the November 2021 proposal, the EPA sought comment on this minimum detection threshold for the advanced measurement technologies used in the alternative screening approach and solicited data on the current detection sensitivity of commercially available methane detection technologies as deployed, as well as other data that could be used to support consideration of a different minimum detection threshold. The EPA also solicited comment on development of a survey matrix for the alternative screening approach option, where instead of prescribing one detection threshold and screening frequency, the frequency of screening surveys would be based on the sensitivity of the technology (*i.e.*, screening surveys performed with technologies with the lower detection thresholds would need to be performed less frequently than screening surveys performed with technologies with higher detection thresholds).

The November 2021 proposal also included a requirement for owners and operators to include information specific to the alternative screening approach in their fugitive emissions monitoring plan. This would include information on which sites are utilizing this alternative screening option; a description of the measurement technology used for screenings; verification of the methane detection threshold, with supporting data to support the verification; procedures for daily verification of sensitivity under field conditions; standard operating procedures; and methodology for conducting the screening. The EPA solicited comment on when notifications would be required for sites where the alternative standard is applied and whether submission of the monitoring plan and/or Agency approval before utilizing the alternative standard was necessary to ensure consistency in screening survey procedures in the absence of finalized methods or procedures.

When fugitive emissions are detected through a periodic screening survey, the EPA proposed to require a ground based OGI survey of all fugitive emissions components at the site within 14 days of the screening survey. Due to the significance of the emissions events detected through screening, an expeditious timeframe was proposed, but the EPA requested additional information to fully evaluate the appropriateness of this proposed 14-day deadline for a follow-up OGI survey. Further, the EPA proposed to require

repair of all fugitive emissions identified during the follow-up OGI survey in accordance with the same repair deadlines as those for regular fugitive surveys (*i.e.*, a first attempt at repair within 30 days of the OGI survey and final repair completed within 30 days of the first attempt). However, because large emissions events, especially those identified during the screening surveys, contribute disproportionately to emissions, the EPA solicited comment on creating a tiered repair deadline requirement that would be based on the severity of the fugitive emissions identified. The EPA also noted that some equipment types with large emissions warrant a requirement for a root cause analysis rather than simply requiring the equipment to be repaired and solicited comment on how a root cause analysis with corrective action approach could be applied in the proposed alternative screening approach.

b. Changes to Proposal and Rationale

The EPA received overwhelming support for the inclusion of an option to use advanced technologies for periodic screenings as an alternative to the fugitive emissions monitoring and repair program proposed in NSPS OOOOb and EG OOOOc. However, commenters remarked that the Agency failed to provide sufficient supporting evidence for the proposed minimum detection threshold of 10 kg/hr. Commenters provided alternative minimum detection thresholds and/or monitoring frequencies; many of these commenters provided supporting evidence for equivalency to the proposed fugitive emission monitoring and repair program in NSPS OOOOb and EG OOOOc, including results from LDAR program effectiveness models, such as FEAST. However, the results of these models varied widely, and as such, it was difficult to compare the different thresholds and frequencies presented by commenters. Additionally, one commenter suggested the EPA should investigate the role of modeling in equivalency demonstrations because the modeling outputs are highly impacted by the model inputs and assumptions made in the models.⁸³ Commenters also encouraged the EPA to adopt a survey matrix for the alternative screening approach option that would allow owners and operators to vary the frequency of periodic screening surveys based on the detection sensitivity of the screening survey technology. Commenters stated that the EPA should

⁸³ See Document ID No. EPA-HQ-OAR-2021-0317-0747.

use existing publicly available LDAR program effectiveness models⁸⁴ to determine a matrix of survey frequencies and detection thresholds that would provide a demonstration of equivalency between the alternative screening and the standard fugitive emissions monitoring and repair program.

Based on these comments and subsequent discussions with commenters,⁸⁵ the EPA decided that the best course of action for determining equivalency between different fugitive emission programs would be to run one of the leak detection and repair program effectiveness models with a set of standardized model inputs. For this effort, the EPA chose to conduct the modeling using FEAST so we could directly compare alternatives to the results of the OGI fugitive emissions program proposed as the BSER described in section IV.A of this preamble.⁸⁶

Based on recent aerial and satellite studies,^{87 88} a primary advantage of more frequent screening with advanced technologies is to quickly identify large emission events (commonly referred to as “super-emitters”). These super-emitters may be the result of large leaks from fugitive emissions components, but may also result from other sources, such as unlit flares or process malfunctions. Therefore, for this equivalency assessment, the EPA included emissions from other sources beyond fugitive emissions components that contribute to these super-emitters. This emissions distribution was developed using aerial study data from

Cusworth, *et al.*,⁸⁹ and supplemented to include additional leaks between the lower limits of detection of the aerial surveys (about 15 to 20 kg/hr) and high-flow samplers commonly used in ground-level quantification studies (maximum quantification limit of about 9 kg/hr). The EPA assumed the small model plants (Model Plants 1 and 2) have one potential super-emitter source and that the larger model plant (Model Plant 4) has two potential super-emitter sources. The EPA evaluated the impact of different super-emitter frequencies but conducted the equivalency modeling using the 1.0 percent leak generation rate based on data from Zavala-Araiza, *et al.*⁹⁰ Additionally, the EPA performed a sensitivity analysis where we assumed a 1.0 percent leak generation rate for larger emissions sources commonly identified using aerial screening technologies (>26 kg/hr) and a 0.5 percent leak generation rate for fugitive emissions components consistent with the analysis for OGI and AVO programs described in section IV.A. More detail on the FEAST modeling assumptions and simulations is provided in the Supplemental TSD for this action located at Docket ID No. EPA-HQ-OAR-2021-0317. The EPA solicits comment on the use of LDAR effectiveness models in the development of the requirements for the alternative screening approach, specifically on the appropriateness of the inputs and assumptions used in the EPA’s FEAST modeling simulations.

In this action, the EPA is revising the proposal for the alternative screening approach to provide additional

flexibility to owners and operators to show that the advanced technology for which they are seeking approval would reduce fugitive emissions at least equivalent to the reduction under the proposed fugitive emission monitoring and repair program in NSPS OOOOb and EG OOOOc, as well as the proposed covers and CVS requirements in NSPS OOOOb and EG OOOOc. Instead of requiring a fixed screening survey frequency for all technologies, the EPA is proposing a survey matrix, where the minimum detection threshold of the screening technology determines the frequency of screening surveys and whether an annual OGI ground-based survey is needed as a supplement to the periodic screening surveys. Tables 20 and 21 present the details of the screening matrix for facilities required to conduct quarterly and semiannual OGI ground-based monitoring under the proposed fugitive emissions monitoring and repair program in NSPS OOOOb and EG OOOOc, respectively. Based on the FEAST modeling the EPA performed, technologies with a minimum detection threshold above 30 kg/hr could not be deemed equivalent to the proposed fugitive emissions monitoring and repair program in NSPS OOOOb and EG OOOOc at any screening survey frequency, even when coupled with an annual OGI ground-based survey. As such, the alternative periodic screening approach is limited to technologies with a minimum detection threshold less than or equal to 30 kg/hr.

TABLE 20—SURVEY MATRIX FOR ALTERNATIVE PERIODIC SCREENING APPROACH FOR AFFECTED FACILITIES SUBJECT TO QUARTERLY OGI MONITORING ^a

Minimum screening frequency	Minimum detection threshold of screening technology ^b
Quarterly + Annual OGI	≤1 kg/hr
Bimonthly	≤2 kg/hr
Monthly	≤4 kg/hr
Bimonthly + Annual OGI	≤10 kg/hr
Monthly + Annual OGI	≤30 kg/hr

^a Well sites with major production and processing equipment, controlled storage vessels, natural gas-driven pneumatic controllers, associated covers and closed vent systems, and control devices, centralized production facilities, and compressor stations.

^b Based on a probability of detection of 90 percent.

⁸⁴ Currently, the free publicly available simulation models are Fugitive Emissions Abatement Simulation Toolkit (FEAST) and Leak Detection and Repair Simulator (LDAR-Sim).

⁸⁵ See February 18, 2022, memorandum, *Summary of Meeting with American Petroleum Institute*, and February 28, 2022, memorandum, *Summary of Meeting with Environmental Defense*

Fund located at Docket ID No. EPA-HQ-OAR-2021-0317.

⁸⁶ The EPA used FEAST version 3.1 to model the various programs. While the EPA used FEAST in this modeling exercise, the EPA would expect other available modeling simulation tools to produce similar results.

⁸⁷ Chen, Yuanlei, *et al.* 23 Mar 2022, <https://doi.org/10.1021/acs.est.1c06458>.

⁸⁸ Irakulis-Loitxate, Itziar, *et al.* 30 June 2021, <https://doi.org/10.1126/sciadv.abf4507>.

⁸⁹ Cusworth, Daniel, *et al.* 2 June 2021, <https://pubs.acs.org/doi/10.1021/acs.estlett.1c00173>.

⁹⁰ Zavala-Araiza, Daniel, *et al.* 16 Jan 2017, <https://doi.org/10.1038/ncomms14012>.

TABLE 21—SURVEY MATRIX FOR ALTERNATIVE PERIODIC SCREENING APPROACH FOR SINGLE AND MULTI-WELLHEAD ONLY SITES AND SMALL WELL SITES

Minimum screening frequency	Minimum detection threshold of screening technology ^a
Semiannual	≤1 kg/hr
Triannual	≤2 kg/hr
Triannual + Annual OGI	≤5 kg/hr
Quarterly + Annual OGI	≤15 kg/hr
Monthly + Annual OGI	≤30 kg/hr

^a Based on a probability of detection of 90 percent.

These survey matrices will provide owners and operators who choose to implement the alternative periodic screening approach a wider selection of methane detection technologies from which to choose. The matrices also provide clear goals for vendors interested in the development of future technologies for methane detection. The EPA solicits comments on the survey matrices developed for the alternative periodic screening approach. Specifically, the EPA is interested in comments regarding the applicability of this matrix to both currently available technologies and those currently in development. Further, where specific technologies may not easily work within the context of the proposed matrix, we are soliciting detailed information on how those specific technologies work, including empirical data that would allow for additional evaluation of parameters in the proposed matrix; how emissions reduction equivalency can be demonstrated for those technologies compared with the standard OGI work practice; and changes that would be needed to the proposed matrix and the basis for those changes. Finally, we are soliciting feedback from owners and operators on ways to improve and further incentivize use of the proposed matrix approach to ensure they are comfortable utilizing any approved alternative technologies and test methods.

To reflect changes made to the proposed alternative periodic screening approach, the EPA is also modifying the proposed requirements for site-specific monitoring plans. The EPA is proposing to allow owners and operators to develop a site-specific monitoring plan or to develop a monitoring plan that covers multiples sites. At a minimum, the monitoring plan would need to contain the following information: (1) Identification of each site that will be monitored through periodic screening, including latitude and longitude coordinates; (2) identification of the test

method(s) used for the periodic screening; (3) identification and contact information for the entity performing the periodic screening; (4) frequency for conducting periodic screenings; (5) procedures for conducting ground-based monitoring surveys in response to confirmed emission detection events from periodic screening surveys; (6) procedures and timing for identifying and repairing fugitive emissions components, covers, and CVS; (7) procedures and timing for verifying repairs for fugitive emissions components, covers, and CVS, and (8) recordkeeping and retention requirements.

The EPA is also clarifying the timeframes for when owners and operators must conduct the initial periodic screening survey when complying with the alternative periodic screening standard. In the November 2021 proposal, the EPA did not include timeframes for initiating periodic monitoring. The EPA is proposing that, for the initial periodic screening survey must be conducted within 90 days of the startup of production for each fugitive emissions components affected facility and/or storage vessel affected facility located at a new, modified, or reconstructed well site or centralized production facility and have not begun any fugitive monitoring; within 90 days of startup for each fugitive emissions components affected facility and storage vessel affected facility located at a new compressor station; and within 90 days of modification for each fugitive emissions components affected facility and storage vessel affected facility located at a modified compressor station. This 90-day initial screening requirement is the same as that required for the OGI-based fugitive emissions surveys. Additionally, the EPA is proposing that the initial periodic screening survey must be conducted no later than the date of the next required OGI fugitive emissions survey for any affected facility that was previously

complying with the proposed fugitive emissions monitoring and repair program and proposed covers and CVS requirements in NSPS OOOOb and EG OOOOc. The EPA solicits comment on the proposed timing to perform the initial periodic screening survey, including information to support different timeframes.

When the periodic screening survey identifies emissions, the EPA is proposing to require a ground-based survey using OGI to identify the source of the emissions and any other fugitive emissions present. Any fugitive emissions identified during this ground-based survey would be subject to repair requirements. For fugitive emissions components, the EPA is proposing to require a completion of repairs within 30 days of the screening survey. The EPA is proposing that if the ground-based survey confirms that emissions were caused by a failure of a control device, the owner or operator must initiate a root cause analysis and determine appropriate corrective action within 24 hours of the ground-based survey. Because a failure of a control device would likely result in violations of the standards, the EPA is proposing appropriate corrective action should be taken as soon as possible to address these failures. Similarly, for covers and CVS, which are either fugitive components or are subject to the proposed cover and CVS requirements, the EPA is proposing to require repair within 30 days of the screening survey. The EPA is also proposing that if a leak or defect in a cover or CVS is identified, the owner or operator would be required to perform a root cause analysis to determine the cause of emissions from the cover or CVS within five days of completing the ground-based inspection, in addition to requiring repair within 30 days of the screening survey. The root cause analysis should include a determination as to whether the system was operated outside of the engineering design analyses and

whether updates are necessary for the system. Because covers and CVS are required to be designed and operated with no identifiable emissions, indications of emissions from these sources could result in violations of the CVS requirements where the CVS is not a fugitive emissions component. Therefore, the EPA is proposing that appropriate corrective actions should be taken to resolve the emissions and ensure that the no detectable emissions standard is continuously met. Examples of corrective actions might include replacement of gaskets with a material more suitable for the composition of materials in the storage vessel or redesign of the entire CVS to ensure pressure setpoints are appropriate for relief devices on storage vessels. The EPA understands that the length of time necessary to complete corrective actions will vary based on the specific action taken. Therefore, we are soliciting comment on an appropriate deadline by which all corrective actions should be completed that would account for variability in complexity for such actions.

2. Alternative Continuous Monitoring Systems

a. Summary of November 2021 Proposal

In the November 2021 proposal, the EPA recognized that the alternative screening approach as outlined above may not be well suited to continuous monitoring technologies, such as sensors or open-path technology, even though these technologies may meet the minimum methane detection threshold (86 FR 63176; November 15, 2021). To incentivize these continuous monitoring technologies, which could be valuable tools in quickly detecting large emissions events, as well as identifying when emissions at the site begin to rise, the EPA requested information that could be used in an equivalence demonstration and would allow for the development of a flexible framework that could cover multiple types of continuous monitoring technologies and be used as a second alternative approach to the fugitive emissions monitoring and repair program in NSPS OOOOb and EG OOOOc. Specifically, the EPA requested information on the number of continuous monitors needed on a site, placement criteria for these monitors, response factors, minimum detection levels, frequency of data readings, how to interpret the monitor data to determine the difference between detected emissions and baseline emissions, how to determine allowable emissions versus leaks, the meteorological data criteria,

measurement systems data quality indicators, calibration requirements and frequency of calibration checks, how downtime should be handled, and how to handle situations where the source of emissions cannot be identified even when the monitor registers a leak.

b. Changes to Proposal and Rationale

In response to the solicitation for comment on the development of a framework for continuous monitoring technologies in the November 2021 proposal, the EPA received comments from vendors, trade groups, industry, and environmental groups in support of developing a framework for these technologies. Many of these commenters discussed the benefits of continuous monitoring systems including the low detection sensitivities of the technologies, the potential savings involved in identifying the largest leaks in near real time, and the potential to repair leaks on a much quicker timeframe. The EPA is proposing a framework for continuous monitoring technologies that is akin to the fence-line monitoring work practice promulgated by the EPA in 2015 as part of the National Emissions Standards for Hazardous Air Pollutants (NESHAP) for the petroleum refinery sector (80 FR 75178; December 1, 2015). Under this proposed approach, an owner or operator utilizing continuous monitoring technologies would conduct a root cause analysis and corrective action whenever a methane emission rate action-level is exceeded at the boundary of a facility.

The EPA is proposing methane emissions rate (*i.e.*, kg/hr) based action levels instead of methane concentration (*e.g.*, ppmv) based action levels (as in the Refineries NESHAP) in order to: (1) Account for upwind contributions from other sites and meteorological effects and (2) allow the Agency to evaluate the methane emissions reductions achieved by this framework, thus providing for a metric to demonstrate equivalency with the proposed fugitive emissions monitoring and repair program and proposed covers and CVS requirements in NSPS OOOOb and EG OOOOc. Through the comments received and subsequent discussions with commenters,⁹¹ the EPA has gathered information on how these continuous monitoring systems have been applied and how owners and operators use the information from these systems to initiate a response to identify and repair

leaks. The application of these systems appears to vary widely across the industry, with no consistent standard currently employed. This is especially true for how sources initiate identification of the cause of a leak. To standardize the use of these systems across the industry, the EPA is proposing two action levels in this alternative continuous monitoring approach: (1) A long-term action level to limit emissions over time and (2) a short-term action level to identify large leaks and malfunctions. Both action levels would apply to all owners and operators choosing to use this alternative, and a root cause analysis and corrective action would be triggered when either action level is exceeded. The proposed long-term action levels are developed from the same FEAST Model used for the development of the proposed survey matrix for periodic screening and the action-levels are based on the annual emissions (including super-emitters) of our Model Plant 2 and Model Plant 3 discussed in section IV.A.2 of this preamble. Based on this data, the EPA is proposing an action-level of 1.2 kg/hr⁹² for sites consisting of only wellheads and 1.6 kg/hr⁹³ for all other well sites and compressor stations with equipment. This long-term action level would be based on a rolling 90-day average, where the 90-day average would be recalculated each day. The EPA is also proposing a short-term action-level of 15 kg/hr for sites consisting of only wellheads and 21 kg/hr for other well sites and compressor stations. These action levels are based on the same magnitude of emissions as the long-term action level; however, the rates are defined over the period of seven days. The short-term action level would be based on a rolling 7-day average, where the 7-day average would be recalculated each day. The EPA solicits comment on the proposed short-term and long-term action levels. The EPA is also aware of industry led efforts⁹⁴ to minimize methane emissions through the entirety of the value chain using the percentage of intensity or production as a metric. The EPA is soliciting comment on the potential use of intensity or production in the development of action levels, including appropriate thresholds for setting such action levels on both a short-term and long-term basis.

The EPA is aware of other continuous monitoring systems using technologies that are not designed to quantify a site-level methane emissions rate (*e.g.*,

⁹¹ See memorandum, *Summary of Meetings on Alternative Screening and Continuous Monitoring Systems* located at Docket ID No. EPA-HQ-OAR-2021-0317.

⁹² 11.6 tons per year methane.

⁹³ 15.5 tons per year methane.

⁹⁴ One Future Coalition.

camera based continuous systems). While the EPA believes these systems could be useful in a methane mitigation program, they are not suitable for the proposed alternative continuous monitoring approach because they are not capable of quantifying site-level methane emissions, which is the basis for the equivalency demonstration of the proposed alternative continuous monitoring approach. That said, the EPA solicits comment on how these types of systems could fit within the alternative continuous monitoring approach, what action levels should be applied to a non-emission rate based continuous monitoring system, and data to support those action levels in order to conduct an equivalency demonstration. The EPA also solicits comment on whether a different type of approach should be used for these other types of continuous monitoring systems, and if so, what that approach would look like and how equivalency could be demonstrated between the approach and the proposed fugitive emissions monitoring and repair program and proposed covers and CVS requirements in NSPS OOOOb and EG OOOOc.

The EPA is proposing that owners and operators must initiate a root cause analysis within 5 calendar days of an exceedance of either the short-term or long-term action level. Additionally, the EPA is proposing that the initial corrective action identified must be completed within five calendar days of an exceedance of the short-term action level and within 30 calendar days of an exceedance of the long-term action level. If, upon completion of the initial corrective actions, the continuous monitor readings remain above an action level, or if all identified corrective action measures require more than 30 days to complete, the owner or operator would be required to develop a corrective action plan and submit it to the Administrator within 60 calendar days of the initial action level exceedance. The EPA is soliciting comment on the proposed requirements for the root cause analysis and corrective action, the timeframes for conducting these activities, and the requirement for corrective action plan submittals.

In order to ensure that the continuous monitoring systems used in the alternative continuous monitoring approach are sensitive enough to trigger at the proposed action levels, the EPA is proposing that the continuous monitoring systems must have a detection level an order of magnitude less than the proposed action level and that the system must produce a valid mass emissions rate (*i.e.*, kg/hr) from the

site at least once every twelve hours. The EPA is also proposing requirements related to operability of the monitors within the continuous monitoring system. Specifically, the EPA is proposing that the operational downtime of the continuous monitoring system, or the time that any monitor fails to collect or transmit quality assured data, must be less than or equal to 10 percent on a 12-month rolling average, where the 12-month average is recalculated each month. We are soliciting comment on this approach to addressing downtime and other ways to address system downtime and the consequences of that downtime.

Similar to the alternative periodic screening approach, owners and operators who choose to implement the alternative continuous monitoring approach must develop a monitoring plan. The monitoring plan can either be a site-specific monitoring plan or cover multiples sites. At a minimum, the monitoring plan would need to contain the following information: (1) Identification of each site that will be monitored through periodic screening, including latitude and longitude coordinates; (2) identification of the test method(s) used for the continuous monitoring; (3) identification and contact information for the entity performing the continuous monitoring if the continuous monitoring system is administered through a third-party provider; (4) number and location of monitors; (5) system calibration procedures and schedules; (6) identification of critical components and procedures for their repairs; (7) procedures for out of control periods; (8) procedures for determining when a fugitive emissions event is detected by the continuous monitoring technology; (9) procedures and timing for identifying and repairing fugitive emissions components, covers, and CVS; (10) procedures and timing for verifying repairs for fugitive emissions components, covers, and CVS, and (11) recordkeeping and retention requirements.

The EPA is proposing that owners and operators who choose to comply with the alternative continuous monitoring approach must install and begin conducting monitoring with the continuous monitoring system within 120 days of the startup of production for each fugitive emissions components affected facility or storage vessel affected facility located at a new, modified, or reconstructed well site or centralized production facility; within 120 days of startup for each fugitive emissions components affected facility and storage vessel affected facility

located at a new compressor station; and within 120 days of modification for each fugitive emissions components affected facility and storage vessel affected facility located at a modified compressor station. Additionally, the EPA is proposing the continuous monitoring system must begin monitoring no later than the date of the next scheduled OGI monitoring survey for any affected facility that was previously complying with the proposed fugitive emissions monitoring and repair program and proposed covers and CVS requirements in NSPS OOOOb and EG OOOOc. The EPA solicits comment on the proposed timing to install and begin conducting monitoring with the continuous monitoring system, including information to support different timeframes.

The EPA is soliciting comment on this proposed alternative continuous monitoring approach, especially the use of site-level methane emissions as a surrogate for VOC emissions, the practicality of implementing the proposed framework, and any additional data on how continuous monitoring technologies have been deployed at well sites, centralized production facilities, and compressor stations. The EPA proposes to use the continuous monitoring system to confirm the effectiveness of the corrective action and has proposed additional repair and notification requirements for when corrective action is delayed or when the corrective action is ineffective.

3. Alternative Test Method Approval

a. Summary of November 2021 Proposal

The EPA solicited comment on whether owners and operators choosing to comply with the alternative periodic screening approach would need to submit their monitoring plan to the delegated authority and whether Agency approval was necessary before the owner or operator could implement the alternative. The EPA proposed that EPA approval may be necessary to ensure consistency in screening survey procedures in the absence of finalized methods and procedures.

b. Changes to Proposal and Rationale

The EPA received comments from industry, state agencies, and non-governmental organizations acknowledging that review and approval of individual monitoring plans increases the burden on industry. Additionally, the review of these monitoring plans increases the burden on delegated authorities to evaluate the alternative technologies and may result

in inconsistent application or variable approvals for the same technology between different states. The EPA also received direct comment⁹⁵ from one state that expressed that the EPA should serve as the clearinghouse for approving these advanced measurement techniques.

The EPA continues to find that, prior to implementation, approval of the technologies used in the alternative periodic screening approach and the alternative continuous monitoring approach is necessary due to the lack of standard methods and performance specifications for these types of systems. Approval of these systems will allow a wider range of methane detection techniques to be applied, but also allow the Agency to provide more specific guidance on the proper operation of these systems. Based on the comments received, the EPA is proposing to require these systems to be approved by the Administrator under the alternative test method provisions in 40 CFR 60.8(b)(3) instead of owners and operators seeking approval of these systems through site-specific monitoring plans. The use of the alternative test method provisions has typically been applied to the approval of alternative test methods used to conduct performance testing to demonstrate compliance with a numerical emission standard. While work practice standards are not numerical emission standards, there is precedent for approving alternative test methods within work practice standards, so long as the change in the testing or monitoring method or procedure will provide a determination of compliance status at the same or higher stringency as the method or procedure specified in the applicable regulation.⁹⁶⁹⁷ The EPA is soliciting comment on the use of this provision at 40 CFR 60.8(b)(3) for the approval of the alternative test method for an alternative technology for measurements within the proposed alternative periodic screening approach and the proposed alternative continuous monitoring approach.

Once an alternative test method for an alternative technology has been approved, if it is broadly applicable, the EPA will post it to the Emission Measurement Center website.⁹⁸ Any owner or operator who meets the specific applicability for the alternative test method, as outlined in the alternative test method, may use the alternative test method to comply with the alternative periodic screening approach or alternative continuous monitoring approach. The owner or operator would be required to notify the Administrator of adoption of the alternative periodic screening approach or alternative continuous monitoring approach in the first annual report following implementation of the alternative standard. The owner or operator's fugitive emissions monitoring plan would identify the approved alternative test method(s) the owner or operator is using the alternative periodic screening approach or alternative continuous monitoring approach.

In an effort to streamline the approval process and reduce the time needed for processing these request for alternative test methods, the EPA is proposing the following pre-qualifications for those requesting approval of their technology: (1) Requestors are limited to any individual or organization located in or that has representation in the U.S.; (2) requestor must have direct knowledge of the design, operation, and characteristics of the underlying technology; (3) the underlying technology must have been applied to methane measurements in the oil and gas production, processing, and/or transmission and storage sectors either domestically or internationally; (4) the technology must be a commercial product, meaning it has been sold, leased, or licensed, or offered for sale, lease, or license, to the general public. While the EPA has based these pre-qualifications on comments received from vendors or advanced methane detection technologies, the EPA solicits comments on how we have characterized the pre-qualifications in this proposal and whether any additional pre-qualifications may be appropriate.

In an effort to streamline the approval of these requests by ensuring adequate information is received in the request to allow a full evaluation of the alternative technology, the EPA is proposing that any application for an alternative test method contain the following information at a minimum: (1) The desired applicability of the technology

(i.e., site-specific, basin-specific or broadly applicable across the sector); (2) a description of the measurement systems; (3) supporting information verifying that the technology meets the desired detection threshold(s) as applied in the field; (4) a detailed description of the alternative testing procedure(s), including data quality objectives to ensure the detection threshold(s) are maintained and procedures for a daily verification check of the measurement sensitivity under field conditions, and; (5) standard operating procedures consistent with the EPA's guidance and including safety considerations, measurement limitations, personnel qualification/responsibilities, equipment and supplies, data and record management, and quality assurance/quality control. The EPA solicits comment on the proposed information required to be submitted with the application of an alternative test method and whether the EPA should consider requiring any additional information.

The EPA is proposing a defined timeframe for review and determination of alternative test method requests by the Agency. The EPA is proposing to issue either an approval or disapproval in writing to the requestor within 270 days of receipt of the request, with a number of milestones for acknowledgement of receipt and initial reviews. The EPA is also proposing a mechanism to allow a conditional approval of a submitted alternative test method in the event a determination is not made by the Agency within 270 days. Finally, the EPA is maintaining the authority to rescind any previous approval if we find it reasonable to dispute the results of any alternative test method used to demonstrate compliance with either the alternative periodic screening approach or the alternative continuous monitoring approach. The EPA proposes to make these approvals and the supporting information available to the public on an EPA supported website. The EPA solicits comments on the proposed timeframe to review and approve alternative test methods and whether alternative timelines should be considered.

C. Super-Emitter Response Program

Although results vary by basin, many studies have found that the top five percent of sources contribute over 50 percent of the total emissions.⁹⁹ There is

⁹⁵ See Document ID No. EPA-HQ-OAR-2021-0317-0763.

⁹⁶ In amendments to the approval of state programs and delegation of federal authorities, the EPA clarified that certain provisions within work practices, such as those related to compliance and enforcement provisions, are delegable provisions. In particular, the EPA stated that monitoring requirements are delegable. See 65 FR 55810 (September 14, 2000).

⁹⁷ The fenceline monitoring work practice in 40 CFR part 63 subpart CC allows owners and operators to seek an alternative test method for use of technologies other than the prescribed sorbent tube monitoring with Method 325 A and B of appendix A to 40 CFR part 63. See 40 CFR 63.658(k)(1).

⁹⁸ <https://www.epa.gov/emc/oil-and-gas-approved-alternative-test-methods>.

⁹⁹ Yuanlei Chen *et al.*, "Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey," *Environmental Science and Technology*, Vol. 56, No. 7 (March 2022), <https://doi.org/10.1021/acs.est.1c06458>.

wide agreement in the peer-reviewed research that a subset of sources comprising the very largest emission events, commonly referred to as super-emitters, is typically caused by abnormal operating conditions or malfunctions.¹⁰⁰

Many of the requirements of this rule, when implemented correctly, would result in reducing the number of super-emitter emissions events. For the reasons described below, the EPA is further proposing a super-emitter response program as a backstop to address the large contribution of super-emitters to the pollution from this sector. For purposes of this program, the EPA is proposing to define a super-emitter emissions event as quantified emissions of 100 kg/hr or greater of methane, a very high threshold that encompasses the largest emissions events.

Recognizing that super-emitter emissions events are a significant source of methane and VOC emissions, the November 2021 proposal and this supplemental proposal contain standards and requirements that, if implemented correctly, would prevent (e.g., via zero-emissions standards for pneumatic controllers and design and operation requirements for flares) or detect and mitigate (e.g., via regular monitoring for fugitive emissions using OGI or advanced detection technologies) most of these large emissions events.¹⁰¹ We note that the estimated emission reductions in both the November 2021 proposal and this supplemental proposal likely undercount the emission reductions that would be achieved by this rule because they might not fully account for the emissions resulting from all super-emitter emissions events that would be prevented or quickly corrected

as a result of this rule. Though we are not currently able to quantify the emissions reductions likely to result from preventing or more quickly mitigating super-emitter emissions events, we note that the information presented in appendix D to the RIA for this supplemental proposal includes model simulations suggesting that covering large emitters could “significantly impact[] the expected emissions from the fugitive emission program.”¹⁰²

It is clear from the estimates from the two proposals that these methods are expected to result in the prevention, detection, and repair of many current super-emitters. Sites that take advantage of opportunities for continuous emissions monitoring offered by the alternative monitoring strategies the EPA has proposed may be particularly able to quickly identify and timely address these events.

However, super-emitters’ significant impact on the communities where they are located, as well as their greatly disproportionate contribution to emissions in total, call for additional measures to backstop compliance and address the unique characteristics of these events. The abnormal process conditions that characterize these events can be persistent or episodic, meaning that while some sources are consistent super-emitters, many such large emissions events are intermittent and can occur at different sites over time.¹⁰³ A cost-effective inspection program can therefore miss some of these super-emitter events, even if implemented in accordance with the proposed standards. We further note that oil and gas facilities, in particular those in remote areas, may not have personnel present when super-emitter emissions events occur. Given the large number

and broad geographic distribution of affected sources and designated facilities to be regulated under this rule, the EPA also recognizes that the need for rigorous compliance assurance will be particularly important in this source category.

The same sophisticated research and constantly advancing new monitoring technologies that have contributed to our understanding of the serious problem of super-emitters can bolster the other standards and requirements included in this proposal and serve to help identify and mitigate any super-emitter emissions events. The super-emitter response program, which the EPA outlined conceptually in the November 2021 proposal for public comment and which we are now proposing here, would allow the use of reliable and demonstrated remote sensing technology deployed by experienced, certified entities or regulatory authorities to find these large emissions sources. As described in the November 2021 proposal, this proposed super-emitter response program builds on the growing use of these advanced technologies by a variety of entities to identify and mitigate super-emitting events.

This proposed program establishes a pathway by which an EPA-approved entity or regulatory authority may provide credible, well-documented identification of a super-emitter emissions event using one of several permitted technologies and approaches, and then notify the responsible owner or operator. Once notified of the event, owners and operators would be required to perform a root-cause analysis and take corrective actions to address the emissions source at their individual well sites, centralized production facilities, and compressor stations. Upon conducting the root-cause analysis, the owner or operator may determine that all necessary and appropriate actions have been taken and that no additional action is needed. However, if the owner or operator confirms the existence of a super-emitter emissions event that requires mitigation—either due to a failure to comply with one of the standards in this rule or due to an upset or malfunction at a source covered by this rule—then the owner or operator must take prompt steps to eliminate the super-emitter emissions event and report both its root-cause analysis and corrective actions to the EPA and the appropriate state or tribal authority. To ensure this program operates in a transparent manner, the EPA will make available in a document repository the notices to operators that the EPA receives, as well as the reports

¹⁰⁰ Daniel Zavala-Araiza *et al.*, “Super-emitters in Natural Gas Infrastructure are Caused by Abnormal Process Conditions,” *Nature Communications* Vol. 8 (January 2017), <https://doi.org/10.1038/ncomms14012>; Ramón A. Alvarez *et al.*, “Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain,” *Science*, Vol. 361 (July 2018), <https://doi.org/10.1126/science.aar7204>; Daniel H. Cusworth *et al.*, “Intermittency of Large Methane Emitters in the Permian Basin,” *Environmental Science and Technology Letters* Vol. 8, No. 7 (June 2021), <https://doi.org/10.1021/acs.estlett.1c00173>; Jeffrey S. Rutherford *et al.*, “Closing the Methane Gap in US Oil and Natural Gas Production Emissions Inventories,” *Nature Communications* Vol. 12 (August 2021), <https://doi.org/10.1038/s41467-021-25017-4>; Yuanlei Chen *et al.*, “Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey,” *Environmental Science and Technology*, Vol. 56, No. 7 (March 2022), <https://doi.org/10.1021/acs.est.1c06458>.

¹⁰¹ Super-emitter emissions events could also be from intentional venting as part of normal operations or maintenance. The proposed super-emitter response program discussed in this section is not intended to address these events.

¹⁰² As stated, some of the model simulations in appendix D to the RIA for this supplemental proposal suggest that large-emitters could significantly impact the estimated emissions reductions; however, those simulations are not directly related to the definition of “super-emitter” included in this proposal, thus the emissions and emission reductions cannot be used to directly assess the emissions or emission reductions related to the proposed super-emitter program. The model simulations relied on information of large emissions from a single basin (Permian), and available data suggest that the frequency of these events may vary significantly across different production basins, which could lead to significant uncertainty if the emission reductions were applied nationwide.

¹⁰³ Daniel Zavala-Araiza *et al.*, “Super-emitters in Natural Gas Infrastructure are Caused by Abnormal Process Conditions,” *Nature Communications* Vol. 8 (January 2017), <https://doi.org/10.1038/ncomms14012>; Daniel H. Cusworth *et al.*, “Intermittency of Large Methane Emitters in the Permian Basin,” *Environmental Science and Technology Letters* Vol. 8, No. 7 (June 2021), <https://doi.org/10.1021/acs.estlett.1c00173>.

sent to the EPA by owners and operators in response, so that notifiers, communities, and owners and operators have quick access to the information submitted to the EPA under the super-emitter provisions.

The EPA believes that the super-emitter response program proposed here will provide a cost-effective and efficient mechanism for comprehensively detecting and addressing super-emitter emission events, complementing and reinforcing the other requirements of this proposal and securing reductions in methane as well as emissions of VOCs and other health-harming air pollutants. In response to the November 2021 proposal, the EPA received comments from representatives of communities affected by air pollution from the oil and natural gas sector, including communities with environmental justice (EJ) concerns, voicing concern about the impacts of these emissions and support for enhanced monitoring efforts. The EPA anticipates that the proposed super-emitter response program will have important benefits for such communities and will create opportunities for communities to partner with entities engaged in remote sensing to monitor nearby sources of emissions. The EPA also anticipates that the proposed transparency requirements for notifications and for follow-up actions by owners and operators will provide valuable information for communities about neighboring sources of emissions and steps taken to mitigate them.

This section begins with a description of the November 2021 proposal and the comments received on that proposal, followed by a description of the specific criteria the EPA is proposing for notifications to sources of super-emitter events and subsequent corrective actions taken to eliminate the emissions. The EPA seeks comment on all aspects of this proposed program.

1. November 2021 Proposal

As described in the November 2021 proposal, “industry, researchers, and NGOs have utilized advanced methane detection systems to quickly identify large emission sources and target ground based OGI surveys. state and local governments, industry, researchers, and NGOs have been utilizing advanced technologies to better understand the detection of, sources of, and factors that lead to large emission events.” See 86 FR 63177 (November 15, 2021). In that proposal, the EPA solicited comment on a potential program for large emission events that would take advantage of data from the

use of advanced technologies that could identify super-emitter emissions events; under the program, if emissions were detected above a defined threshold “by a community, a Federal or state agency, or any other third party, the owner or operator would be required to investigate the event, do a root cause analysis, and take appropriate action to mitigate the emissions, and maintain records and report on such events.” See 86 FR 63177 (November 15, 2021).

2. Rationale for and Summary of Proposed Program

The EPA received numerous comments from industry, non-industry groups, states, tribes, and local communities articulating a range of views on the concept described in the November 2021 proposal. These comments provided valuable information and input on, among other issues, the potential benefits of the program and the importance of comprehensively addressing large emission events; implementation challenges and concerns that would arise in establishing a system by which researchers or other third parties could identify these events and notify owners and operators, including concerns related to ensuring the accuracy of such notifications and providing for safe and lawful monitoring of sources; and the EPA’s legal authority to promulgate such a program under CAA section 111.

The EPA has carefully considered these comments, in conjunction with various peer-reviewed studies, in designing this proposal for a super-emitter response program. As described below, the principal objective of this proposed program is to provide a comprehensive and effective remedy for large emission events that disproportionately contribute to methane emissions from the Crude Oil and Natural Gas source category and can be accompanied by health-harming pollution that affects nearby communities. However, as comments provided by a wide range of stakeholders emphasized, it is also imperative that any such program ensure the safety of entities engaged in monitoring as well as of owners and operators and their employees; utilize accurate, reliable, and rigorous methods for identifying large emission events; and be streamlined and efficient to administer, both for owners and operators of regulated sources as well as for the EPA and the states. The proposed program contains key features and safeguards that were designed with these principles in mind.

As noted above, the EPA assesses this *COM007* program is important both

because of the significant harm associated with super-emitter emissions events and the well-documented challenges in identifying these events. The most widely known sources of unintentional releases resulting in super-emitter emissions events are from controlled tank batteries, flares, natural gas-driven pneumatic controllers, and fugitive emissions components. The standards and requirements included in the November 2021 proposed rule and this supplemental proposal are expected to identify and eliminate many super-emitters when implemented as required. However, a cost-effective inspection program requiring periodic fugitive emissions surveys cannot immediately detect every instance of a super-emitter emissions event or quickly identify when equipment malfunctions occur and therefore may not capture some intermittent or episodic super-emitter emissions events. Further, it is not cost-effective to impose additional inspection costs on every source in hopes of detecting the small percentage of sources that become super-emitters. The proposed super-emitter response program would provide a cost-effective backstop to the rest of the regulatory program by directing operator attention to problems urgently requiring a remedy and providing useful feedback about the effectiveness of the other regulatory requirements.

The EPA faced a similar situation when establishing standards for petroleum refineries, where cost-effective controls and inspections of equipment and operations would not have addressed potentially significant levels of emissions that could occur between regular inspections.¹⁰⁴ In that instance, the EPA required additional monitoring and corrective action to address such high emissions; specifically, the EPA required fenceline monitoring to “identify a significant increase in emissions in a timely manner (e.g., a large equipment leak or a significant tear in a storage vessel seal), which would allow corrective action measures to occur more rapidly than it would if a source relied solely on the traditional infrequent monitoring and inspection methods.” 79 FR at 36920.¹⁰⁵ The EPA is taking a similar approach in this supplemental proposal to address super-emitter emissions events in a timely manner. This program

¹⁰⁴ *Proposed Rule: Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards*, 79 FR 36880, 36920 (June 30, 2014).

¹⁰⁵ This fenceline monitoring requirement is codified at 40 CFR 63.658 of the National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, 40 CFR part 63, subpart CC.

is likewise motivated by the same types of considerations that led the EPA to establish a hotline for reporting oil spills and other environmental releases (e.g., <https://www.epa.gov/emergency-response/national-response-center>). However, unlike most oil spills, large releases of methane are not visible to the human eye; identifying them requires people with specialized equipment and expertise.

The following sections first describe the details of the proposed super-emitter response program, including the definition of a super-emitter emissions event under the program, the requirements for any party that seeks to report a super-emitter emissions event under the program; and the requirements for owners and operators responding to such report. It then describes the statutory structure for the program under CAA section 111.

a. Super-Emitter Response Program Design

Threshold for a super-emitter emissions event. To clearly define what emissions events would be subject to the requirements of this program, the EPA is proposing to define a super-emitter emissions event as any emissions detected using remote detection methods with a quantified emission rate of 100 kg/hr of methane or greater. While the term “super-emitter” has been widely used to describe large emissions events in literature and various other discussions, no specific mass-based or production-based rates have been formally or consistently applied to the term. The EPA is proposing to apply a definition, for purposes of this response program, that focuses on very large emissions events at an individual well site, centralized production facility, compressor station, or natural gas processing plant which warrant immediate investigation.

This threshold definition of 100 kg/hr of methane takes into account several factors. First, this proposed super-emitter response program is intended to provide a mechanism to utilize high quality remote sensing detection of only the largest, most harmful emissions events, and not address all the standards and requirements of NSPS OOOOb and EG OOOOc that are applicable to individual affected facilities and associated controls. The goal of this program is to ensure that if, notwithstanding the other requirements in this proposal, a very large emissions event occurs and is detected by a regulatory authority or qualified third parties using particular technologies, that super-emitting event is quickly addressed. Therefore, the threshold

definition of a super-emitter emissions event needs to be sufficiently high that it does not duplicate other actions (e.g., leak detection and repair) facilities are undertaking to comply with the applicable standards in the rule. Second, where compliance is achieved with the applicable standards, the EPA does not expect unintentional releases at these very high levels to occur in normal operations. Thus, the occurrence of an unintentional release at this emissions rate should be unusual and would clearly warrant immediate investigation and mitigation. Defining a super-emitter event to encompass these unusually large events is therefore consistent with the EPA’s objective of establishing a backstop to the other requirements proposed in this rule. Third, by setting such a high threshold to capture the largest and most concerning emissions events, the program would be more feasible to implement and would properly focus resources on the most significant and potentially harmful sources of emissions. Such high rates of emissions also mean that it is cost effective to quickly address these super-emitters, which release more methane in a single week than the total methane cost-effectively prevented over the course of an entire year at sources covered by the fugitive emissions program. Fourth, as discussed immediately below, this threshold allows the use of remote sensing technologies that are already in use by the EPA, states, and third parties, which could allow the program to be readily implemented upon finalizing NSPS OOOOb and the subsequent state plans required by EG OOOOc.

Technologies that may be used to detect a super-emitter emissions event. Various technologies are available for remote methane detection that would provide a quantified mass emissions rate, including several that would meet the performance criteria proposed for the alternative periodic screening or continuous monitoring for fugitive emissions as described in sections IV.B.1 and IV.B.2 of this preamble. Some commenters stated that thresholds should be defined that could allow the use of a range of technologies, without limiting to one specific class of technologies.¹⁰⁶ Among these, as discussed in the November 2021 proposal, the EPA described its understanding that “some satellite systems are generally capable of identifying emissions above 100 kg/hr

with a spatial resolution which could allow identification of emission events from an individual site.” See 86 FR 63177 (November 15, 2021). Several commenters agreed that the use of satellites for detecting super-emitters was appropriate, while noting that this technology is continuing to advance.¹⁰⁷ Further, several commenters raised concerns regarding potential safety or trespassing on sites with a program using more ground based or close-range detection methods.¹⁰⁸

The EPA agrees with the commenters that some flexibility is appropriate in the type of technology that could be utilized for the detection of super-emitters, provided that the technology can be safely deployed and will reliably identify super-emitter emissions events as defined in this proposal. Considering concerns for the safety of individuals engaged in third-party monitoring and of facility operator personnel, the purposes of this program as described above, and feedback from commenters on the performance and characteristics of various monitoring technologies, the EPA assesses that allowing only remote-sensing technologies is appropriate. Therefore, we are proposing to allow the use of remote-sensing aircraft, mobile monitoring platforms, or satellites to identify super-emitter emissions events. The EPA is soliciting comment on this list of technology types that could be applied for the identification of super-emitter emissions events and the threshold of 100 kg/hr of methane.

Qualifications and requirements for notification of super-emitter emissions events. Next, the EPA is proposing specific requirements related to the notification of a super-emitter emissions event by regulatory authorities and qualified third-party notifiers. Several commenters emphasized the importance of assuring the quality and reliability of the data and suggested that the EPA should have a role in verifying the information to provide that assurance.¹⁰⁹ In order to address concerns about the expertise of the third party identifying the super-emitter event, the EPA is proposing that any

¹⁰⁷ See Document ID Nos. EPA-HQ-OAR-2021-0317-0738, EPA-HQ-OAR-2021-0317-0753, EPA-HQ-OAR-2021-0317-0769, and EPA-HQ-OAR-2021-0317-1391.

¹⁰⁸ See Document ID Nos. EPA-HQ-OAR-2021-0317-0727, EPA-HQ-OAR-2021-0317-0730, EPA-HQ-OAR-2021-0317-0749, EPA-HQ-OAR-2021-0317-0750, EPA-HQ-OAR-2021-0317-0763, EPA-HQ-OAR-2021-0317-0797, EPA-HQ-OAR-2021-0317-0810, EPA-HQ-OAR-2021-0317-0814, EPA-HQ-OAR-2021-0317-0817, EPA-HQ-OAR-2021-0317-0924, and EPA-HQ-OAR-2021-0317-0955.

¹⁰⁹ See Document ID Nos. EPA-HQ-OAR-2021-0317-0738, EPA-HQ-OAR-2021-0317-0938, and EPA-HQ-OAR-2021-0317-0844.

¹⁰⁶ See Document ID Nos. EPA-HQ-OAR-2021-0317-0605, EPA-HQ-OAR-2021-0317-0769, EPA-HQ-OAR-2021-0317-0811, and EPA-HQ-OAR-2021-0317-0844.

third party interested in identifying and notifying owners and operators of super-emitter emissions events must be pre-approved by the Agency for the notification to be valid. This approval process would follow submission of a request for approval as a qualified third-party notifier to the EPA that demonstrates the potential notifier's technical expertise in the specific technologies and detection methodologies proposed for the identification of super-emitter emissions events (*i.e.*, remote-sensing aircraft, mobile monitoring platforms, or satellite). This demonstration would include technical expertise in the use of the detection technology and interpretation, or analysis, of the data collected by the technology. The EPA would maintain a public list of approved qualified third-party notifiers so owners and operators can verify approval before being required to act on a notification. These approved notifiers could be any third party, including but not limited to technology vendors, industry, researchers, non-profit organizations, or other parties demonstrating technical expertise as described. The EPA is soliciting comment on this approval criteria, including whether additional criteria would be appropriate.

Once approved, a qualified notifier would be required to submit specific information in the notification. Providing actionable data of known quality to the owner or operator is essential to ensure resources are focused on swiftly eliminating the super-emitter emissions event. Therefore, the EPA is proposing that each notification must contain specific information to help owners and operators verify that the emissions are correctly linked to their site and aid in a focused investigation to swiftly identify the source of emissions. Specific information that would be required in each notification includes: (1) The location of emissions in latitude and longitude coordinates, (2) description of the detection technology and sampling protocols used to identify the emissions, (3) documentation depicting the emissions and the site (*e.g.*, aerial imaging with emissions plume depicted), (4) quantified emissions rate, (5) date(s) and time(s) of detection and confirmation after data analysis that a super-emitter emissions event was present, and (6) a signed certification that the notifier is an EPA-approved entity for providing the notification, and the information was collected and interpreted as described in the notification. The EPA believes this level of specificity is

necessary to provide owners and operators with credible information, and address the concerns raised by commenters that owners and operators could experience undue burden investigating emissions from monitoring data that are not collected in a rigorous manner. We are soliciting comment on the specific required elements of the notification, including whether additional requirements should be added to aid in verifying the credibility of this information.

The EPA further proposes that the entity making the report shall provide a complete copy to the EPA and to any delegated state authority (including states implementing a state plan) at an address those agencies shall specify. The EPA would then promptly make such reports available to the public online. Third parties may also make such reports available to the public on other public websites. The EPA would generally not verify or authenticate the information in third party reports prior to posting.

The EPA is seeking comment on whether it should establish a procedure for owners and operators to suggest that EPA reconsider the approval granted to a third-party notifier. One type of procedure the EPA has considered would be based on information provided by the owner or operator that demonstrates they had received more than three notices at the same site and from the same third party for super-emitter emissions events which the owner or operator demonstrates, after opportunity for response by the third party, that the notifications contain meaningful, demonstrable errors, including, for example, that the third party did not use the appropriate methane detection technology, or that the emissions event did not exceed the threshold. Where such demonstrable error is identified, the owner and operator would not be obligated to conduct the root-cause analysis and corrective action discussed later in this section and could, instead, submit a report indicating the error. The EPA would not allow use of this type of mechanism to dispute the accuracy of technologies that have been approved by the EPA. Given the intermittency of super-emitter emissions events, the failure of the operator to find the source of the super-emitter emissions event upon subsequent inspection would not be proof, by itself, of demonstrable error on the part of the third-party notifier. The EPA, in its discretion, may remove that third party from the pre-approved list of third-party notifiers upon demonstration by the owner or operator and/or a finding by the EPA that more

than three notifications to that same owner or operator were made in error.

The design of the super-emitter response program ensures that the EPA will make all of the critical policy decisions and fully oversee the program. The proposed framework for the super-emitter response program further includes a robust series of safeguards to ensure that these notifications represent validly collected data and evidence of a super-emitter emissions event. First, the qualified third party permitted to submit notifications must be certified by the EPA as having appropriate experience and expertise. Second, the qualified third party may only use certain remote detection technology approved by the EPA for use in the super-emitter response program. Third, the EPA would establish the threshold defining what emissions events detected by the qualified third parties would trigger any obligation on the part of the owner and operator under the program. Fourth, the EPA has prescribed the specific factual information that must be included in any appropriate notification provided to an owner or operator. And fifth, the EPA has proposed a mechanism for owners and operators to seek a revocation of a notifier's certification from the EPA should they establish that more than one notification contained demonstrable errors. Accordingly, under this framework the qualified third party would essentially only be permitted to engage in certain fact-finding activities and issue fact-based notifications within the limited confines that the EPA has authorized. Such fact-based notifications originating from third parties would not represent the initiation of an enforcement action by the EPA or a delegated authority.

In addition, and as discussed in more detail later in this section, owners and operators would have the opportunity to rebut any information in a notification provided by the qualified third parties in their written report to the EPA, by explaining, where appropriate, that (a) there was a demonstrable error in the third party notification; (b) the emissions event did not occur at a regulated facility; or (c) the emissions event was not the result of malfunctions or abnormal operation that could be mitigated. And, as just discussed, the EPA proposes to retain the authority to revoke a third-party certification upon evidence that the notifier has made repeated, demonstrable errors in notifications provided to owners and operators.

Thus, the EPA believes that the proposed program appropriately limits third party notifiers' discretion and retains oversight by the EPA over all key

decision-making elements of the program. In light of these considerations, the EPA also believes that a greater role for the Agency in reviewing third-party notifications would be an unnecessary task and duplicative of the predicate approval processes and subsequent revocation procedure. Indeed, were the EPA to review third-party notifications, such review could potentially be limited to ensuring that the third party is properly EPA-certified, has used an EPA-approved remote monitoring technology, and has found emissions above the super emitter threshold—all of which are elements that the proposed program structure adequately ensures. The EPA believes other facts necessary to rebut the information in a notification regarding a particular emissions event are likely to only be known by the owner and operator and are best presented in their written report to the EPA. Moreover, given the urgency with which the EPA believes such large emissions events should be addressed, any additional role for the EPA in the notification process would unnecessarily delay mitigation of ongoing harms. The EPA solicits comments on these conclusions, and whether there would be a meaningful benefit to a greater role for the EPA in reviewing and/or approving third-party notifications before the obligation of the owner or operator to respond is triggered. And if so, the EPA further solicits comment on what kind of role would be appropriate without meaningfully delaying the mitigation of the large emissions events this program is intended to target.

Addressing a super-emitter emissions event. In the November 2021 proposal, the EPA solicited comment on what specific actions an owner or operator would be required to take when they are notified of the detection of a super-emitter emissions event. Examples of those specific actions were provided for comment, including verifying the location of the emissions, conducting ground investigations to identify the specific emissions source, conducting a root cause analysis, performing corrective action within a specific timeframe to mitigate emissions, and preventing ongoing and future chronic or intermittent events from that source. See 86 FR 63177 (November 15, 2021). One commenter stated that not all sources of super-emitter emissions events would require a root cause analysis with corrective actions because the emissions may not be the result of malfunctions or abnormal operation (e.g., an emergency blowdown of

equipment).¹¹⁰ Other commenters stated that a root cause analysis and immediate corrective actions should be required for any event identified through this program.¹¹¹

The EPA agrees with commenters that swift action must be taken when an owner or operator is notified about the detection of a super-emitter emissions event to correct any malfunction or abnormal operation that is identified as the cause of the event. First, the owner or operator should confirm that the reported emissions event is traceable to a source located on the notified owner or operator's site and investigate to confirm if a super-emitter emissions event is still ongoing. Further, the EPA agrees that a root cause analysis is necessary to identify the causes of the super-emitter emissions event. Therefore, we are proposing to require owners and operators to initiate a root cause analysis to determine the cause of the super-emitter emissions event and to take corrective actions to mitigate the emissions. Examples of a root cause analysis and corrective action could range from a survey using OGI or other technologies combined with repairs of any leaks identified, to visual inspections of thief hatches and closing any found open or unlatched. As explained in more detail later in this section, such corrective actions are tasks that owners and operators already would undertake to maintain normal operations. One commenter¹¹² noted that the investigation may find the emissions are attributed to something other than a malfunction or abnormal emission; in those cases, the responsive action may only need to include specific documentation of the emissions source, such as maintenance activities, which should be described in the report.

The EPA is proposing to require initiation of the root cause analysis and corrective actions within five calendar days of an owner or operator receiving the notification of the super-emitter emissions event, and completion of corrective actions within 10 days of the notification. Because super-emitter emissions events are such large mass emissions rates (100 kg/hr or greater), it is imperative that mitigation is achieved in a timely manner. One commenter¹¹³ suggested a program where the investigation would start within 14 days

of notification, with repairs completed within 30 days of discovery of the event. However, the EPA believes that identification of the emissions source and remedial action in a much shorter timeframe is both warranted and necessary.

Notwithstanding the necessary urgency of mitigating super-emitter emissions events, the EPA does recognize that in some cases, significant efforts may be required to fully complete required mitigation. It is possible that some corrective actions would take longer than the proposed 10 days to complete. Therefore, the EPA is proposing a requirement for owners and operators to develop and submit a corrective action plan that describes the corrective action(s) completed to date, additional measures that they propose to employ to reduce or eliminate the emissions, and a schedule for completion of those measures. This corrective action plan would be due within 30 days of receipt of the notification of the super-emitter emissions event. This timeframe allows for an additional 20 days beyond the repair deadline to draft the corrective action plan and submit it to the Agency or delegated state authority.

Finally, the EPA is proposing to require the submission of a written report within 15 days of completing the root cause and corrective action to the Agency and delegated state authority. In the case of a designated facility covered by a state plan, the EPA solicits comment on whether such written report should be sent to the state in addition to the EPA. The EPA would promptly post online all reports received from the owner-operator in response to a notice of super-emitter event. This written report would include information such as the data included in the notification, the source of the emissions, corrective actions taken to mitigate the emissions, and the compliance status of the affected facilities. To the extent a deviation or potential violation is identified as the root cause of the emissions, the owner or operator would report that information. If the operator finds that emissions above the super-emitter threshold are not occurring, and there is no evidence that they may have occurred as reported, then the method for making that determination and the evidence in support should be included in the required report to the EPA. To the extent an owner or operator determines that the notification contains a demonstrable error (e.g., that the notifier was not a qualified third party, that the third party did not use the appropriate methane detection technology, or that

¹¹⁰ See Document ID No. EPA-HQ-OAR-2021-0317-1391.

¹¹¹ See Document ID Nos. EPA-HQ-OAR-2021-0317-0586, EPA-HQ-OAR-2021-0317-0605, and EPA-HQ-OAR-2021-0317-0832.

¹¹² See Document ID No. EPA-HQ-OAR-2021-0317-1391.

¹¹³ See Document ID No. EPA-HQ-OAR-2021-0317-0832.

the reported emissions event did not exceed the threshold), the report would need only include a description of the error and an explanation as to why, under these circumstances, a root cause analysis was not conducted. The EPA solicits comment on what other elements should be included in the owner-operator reports to the state and the EPA.

The EPA solicits comment on these proposed deadlines for initiating the analysis and completion of corrective actions. For comments requesting shorter or longer timeframes, we are requesting specific examples that would support any changes to this proposal.

b. Statutory Basis of Super-Emitter Program

There are several ways in which the proposed super-emitter response program described above fits within the EPA's authority under section 111 of the CAA, and two legal frameworks are outlined below.

First, the EPA could treat a super-emitter emissions event as a separate and distinct source of emissions. Under this regulatory framework, sources of super-emitter emissions events from unintended venting would be an affected facility/designated facility, and the super-emitter response program would serve as the standard reflecting the BSER for these facilities.

Specifically, the EPA is proposing a new "super-emitter" affected facility under NSPS OOOOb (and designated facility under EG OOOOc), which the EPA would define as any equipment or control devices, or parts thereof, at a well site, centralized production facility, compressor station, or natural gas processing plant, that causes a super-emitter emissions event (*i.e.*, any emissions detected using remote detection methods with a quantified emission rate of 100 kg/hr of methane or greater). While the other requirements proposed as part of this rulemaking are intended to reduce or eliminate unintentional releases, the super-emitter response program is intended as a backstop to those provisions, to identify any super-emitter emissions events not prevented as a result of other requirements of the proposed rule.

As discussed above, the EPA believes that super-emitter emissions events from unintentional releases tend to occur as a result of equipment malfunctions and/or poor operations; therefore, the BSER for super-emitter emissions events would be to correct the malfunction or operational issues and resume normal operations consistent with the standards or requirements applicable to the source(s) of the super-

emitter emissions event in this proposed rule. The November 2021 proposal and this supplemental proposal contain standards and requirements that, if implemented correctly, would prevent or mitigate these super-emitter emissions events. For example, if a root cause analysis identifies a control device as a source of a super-emitter emissions event, then complying with the requirements for that control device in this proposed rule would bring such device back to normal operation. If the source of a super-emitter emissions event is a leaking fugitive emissions component or an open thief hatch, repairing the component or ensuring that the thief hatch is closed in accordance with the fugitive emissions standards in this proposal would resume these components to normal operation. The super-emitter response program would require that, where approved, qualified third parties or state or Federal governments provide actionable data of known quality about a super-emitter event to owners and operators of a super-emitter affected facility, and owners and operators would conduct a root-cause analysis to identify the sources of the super-emitter emissions and take corrective actions to mitigate the problems in order to resume normal operation. Because specific corrective actions required to resume normal operations would depend on the equipment causing the super-emitter emissions event, and because normal operations could differ from site to site, the proposed program would allow owners and operators to determine the appropriate corrective actions so long as the event is mitigated.

The EPA proposes to determine that these requirements are justified as BSER for this proposed super-emitter affected/designated facility for several reasons. First, we expect that, as part of normal operations, owners and operators should already be correcting equipment malfunctions and/or poor operations as such issues arise; therefore, costs associated with maintaining normal operations should already be accounted for in their operational costs. As mentioned above, the most widely known sources of unintended super-emitter emissions events are from equipment or control devices that would be subject to emission limitations (*e.g.*, 95 percent reduction) or associated compliance assurance requirements in the proposed NSPS OOOOb/EG OOOOc. For these sources, where a super-emitter emissions event suggests a violation of one or more of these standards or requirements, owners and operators would already be required to

investigate the source of the super-emitter emissions event to ensure that it is complying with all applicable standards and requirements. The proposed super-emitter response program would simply require the owner and operator to take these same steps upon receiving notice of a super-emitter emissions event, provided by a regulatory authority or an EPA approved qualified third party, as determined under the proposed program. As explained in more detail above, the proposed super-emitter response program would include a certification process and other criteria to assure the quality and reliability of third-party data regarding a super-emitter emissions event. Having established the reliability and quality of the third-party data regarding a super-emitter emissions event, it is reasonable to require prompt investigation and remediation of the emissions. Super-emitter emissions events could also be caused by fugitive emissions components that, if persistent, would be detected and repaired during the next fugitive monitoring survey; the super-emitter program would simply make the same repair earlier. There would be no associated monitoring cost for owners and operators, as monitoring under this program would be conducted by EPA-approved qualified third parties. Accordingly, the EPA anticipates that there should be no additional cost associated with this work practice standard for the super-emitter emissions event affected facility. The EPA seeks comment on this issue.

To the extent there are additional costs associated with the investigation or mitigation of these events, the EPA anticipates that the costs would be minor in relation to the benefits of stopping such a huge emissions event, making them obviously cost-effective, as explained below. The EPA proposes that it is reasonable to conclude that these actions would be cost effective in light of the large mass emissions rate (100 kg/hr of methane or greater) that would be reduced and the value of the high volume and value of gas saved by mitigation of the event. The EPA finds in the November 2021 proposal and this supplemental proposal that some proposed standards are cost effective when they result in an expected reduction of about 10 tons of methane at a facility over the course of a year. The super-emitters that can be identified through the super-emitter response program produce that amount of methane in five days or less and the

remedies are the same or similar.¹¹⁴ For example, if the source of a super-emitter emissions event is an open thief hatch on a controlled tank battery, the first corrective action would be to close the thief hatch, which would incur negligible costs. In other words, it is highly unlikely that in general these actions would exceed the \$2,185/ton of methane reduced, which is the highest value we have determined to be cost effective for reducing methane in rulemakings addressing methane under section 111 of the CAA. The cost effectiveness for responses to super-emitter emissions events will usually be substantially below this threshold, given that, by definition, super-emitter emissions events emit at least one ton of methane every nine hours, and over 18 tons in a week. For the reasons stated above, the EPA anticipates that requiring immediate corrective actions to resume normal operations to eliminate the super-emitter emission event could be achieved at a reasonable cost for this proposed affected/designated facility. The EPA seeks comment on this conclusion.

The EPA finds that the above regulatory framework of treating super-emitter emissions events from unintended venting as an affected facility that would be subject to the super-emitter response program is a clear, simple, and straight forward approach for addressing such large emission events.

Second, the super-emitter response program can be justified as part of the standards and requirements that apply to individual affected/designated facilities under this rule, a number of which are known to be frequent causes of super-emitter emission events which, as explained earlier, may not necessarily be identified and addressed through more frequent monitoring that we have determined is not cost-effective. As mentioned above, the most widely known sources of unintentional releases resulting in super-emitter emissions events are from controlled tank batteries, flares, natural gas-driven pneumatic controllers, and fugitive emissions, all of which would be either affected facilities or designated facilities under the NSPS OOOOb and EG OOOOc, respectively, or are control devices used on affected facilities/designated facilities for which the proposed rules include specific requirements. The EPA proposes to incorporate the super-emitter program

into these standards by considering the super-emitter program as: (1) An additional compliance assurance measure, in the case of sources that are subject to numerical standards of performance and associated control device requirements, and (2) an additional work practice standard, in the case of sources for which the EPA is proposing work practice standards under this rule. However, despite the proposed incorporation, the super-emitter response program is nevertheless severable from the standards of performance and work practice standards that are being separately established for each of the sources addressed in this rule. Each of these other proposed standards in this rule reflects the use of a specific emission reduction or detection technology or measure that the EPA has determined to be BSER for a given emission source after evaluating its performance, cost and other factors associated with its use, as required by CAA section 111(a) (under the definition of a “standard of performance”). Because whether such technology or measure qualifies as the BSER under CAA section 111(a) does not depend on the presence of the super-emitter response program, the resulting standards of performance and work practice standards proposed in this rulemaking would continue to reflect the use of that technology or measure, and in turn the BSER, even without the super-emitter response program.

Compliance assurance. For super-emitter emissions events from affected facilities/designated facilities subject to numerical standards, the super-emitter response program would serve as an added compliance assurance mechanism, aimed at ensuring compliance with the numerical emissions standards and associated control device or other compliance assurance requirements. Where one of these facilities is determined to be the cause of a super-emitter emissions event, it is reasonable to assume that the emissions source is out of compliance and to require corrective action to bring the facility back into compliance with the applicable standard or requirement.

There are two known sources of unintended venting that could result in super-emitter emissions events that would be subject to numerical performance standards as affected facilities or designated facilities: tank batteries with potential emissions above six tpy of VOC or 20 tpy of methane and natural gas-driven pneumatic controllers. Specifically, for storage vessel affected facilities/designated

facilities, the EPA is proposing a numerical standard of performance that would require reducing VOC and methane emissions by 95 percent. Where a control device is used to meet this standard, the EPA is proposing specific compliance assurance measures, such as a requirement that thief hatches and other openings remain closed (“closed cover requirements”). As discussed in section IV.I of this preamble, the EPA is proposing to require quarterly OGI inspections of thief hatches and other openings to ensure the closed cover requirement, and in turn the 95 percent emission reduction standard, are met. If these standards and requirements are rigorously followed, the EPA anticipates that they should prevent super-emitter emissions events from controlled storage tanks. However, these thief hatches are a commonly known source of super-emitter emissions events when they are not closed and properly latched. The proposed super-emitter response program would therefore serve as a backstop—an additional compliance assurance measure for the storage vessels standards—by requiring corrective action where it is determined that a super-emitter emissions event was caused (in whole or in part) by noncompliant storage vessels. Similarly, with respect to natural gas-driven pneumatic controllers, for which the EPA is proposing a zero-emissions standard, the EPA is proposing to require quarterly OGI inspections of self-contained natural gas-driven pneumatic controllers to ensure there are no identifiable emissions from the controller as a compliance assurance measure. The super-emitter response program would serve as an additional compliance assurance measure by requiring immediate corrective action where it is determined that a super-emitter emissions event was caused (in whole or in part) by a natural gas-driven pneumatic controller affected facility.

As mentioned above, flares are also a widely known cause of super-emitter emissions events. To our knowledge, all flares located at well sites, centralized production facilities, compressor stations, or natural gas processing plants are (or would be) used to meet a performance standard in NSPS OOOOb or EG OOOOc. As such, they would be required to meet the design and operation requirements for flares in this proposal, such as operation and monitoring for a continuous pilot. Flares designed and operated according to the proposed requirements for control devices should not cause a super-emitter emissions event. The super-

¹¹⁴ See Table 11, Summary of Emission Reductions and Cost-Effectiveness: Well Sites with Major Production or Processing Equipment, Quarterly Monitoring.

emitter response program would help assure compliance with these flare requirements (and in turn the relevant performance standards) by requiring owners and operators to take immediate corrective actions to bring that flare into compliance where it is determined that a super-emitter emissions event is caused by a flare. For these sources, where a super-emitter emissions event suggests a violation of one or more of these standards or requirements, owners and operators would already be required to investigate the source of the super-emitter emissions event to ensure that it is complying with all applicable standards and requirements. Since the proposed super-emitter response program would require these same measures, we do not anticipate additional costs associated with the program.

To the extent there are additional costs associated with the investigation or mitigation of these events, the EPA expects that the costs would be minor in relation to the benefits of stopping such a huge emissions event, making them obviously cost-effective. As explained previously in this section, it is reasonable to conclude that these actions would be cost effective in light of the large mass emissions rate (100 kg/hr of methane or greater) that would be reduced and the value of the high volume of gas saved by mitigation of the event.

Work practice standards for detecting and repairing fugitive emissions. As discussed above, super-emitter emissions events may also occur from fugitive emissions components, which are not subject to numerical standards, but rather to a work practice standard that requires periodic monitoring (using OGI, AVO, or an advanced technology) and repair of emissions that are identified from fugitive emissions components. A super-emitter emissions event could occur between the required periodic monitoring and thus not be detected and repaired until the next periodic monitoring event. In addition, if required periodic monitoring is missed, or is not performed well, super-emitter emissions events could be occurring that the periodic monitoring program fails to identify. For affected facilities and designated facilities (*i.e.*, collection of fugitive emissions components) subject to the periodic monitoring and repair requirements, the super-emitter response program would serve as an additional work practice standard that would require corrective action whenever the owner or operator is notified of a super-emitter emissions event by an EPA, a state, or an approved third party under the super-emitter

response program, and it is determined that fugitive emissions components are (in whole or in part) the source of the event.

While, as discussed in section IV.A.1, the EPA does not believe it is cost-effective to require operators to conduct periodic OGI monitoring more frequently than the intervals set out in Section IV.A.1, if a super-emitter emissions event is detected by a regulatory authority or approved qualified third party in between monitoring requirements, the EPA proposes that the BSER include responding to that event and addressing the root cause of the super emission.

The more targeted super-emitter response program would thus be a more effective solution for addressing sporadic, large emission events that may occur outside the periodic OGI monitoring. The conclusion that the super-emitter response program is appropriate for addressing these particularly large emissions events does not undermine the EPA's determination about the frequency of periodic monitoring otherwise required under the fugitive emissions work practice standard. While super-emitter emissions events are important to address as a significant source of potential emission reductions, these events do not occur regularly across all well sites and are not predictable. Accordingly, while the periodic monitoring is appropriate to address more routine leak detection and repair, and to help prevent the occurrence of super-emitter emissions events, the super-emitter response program will help ensure that the unpredictable but potentially significant super-emitter emissions events are expeditiously addressed.

Further, the corrective action to mitigate a super-emitter emissions event from this source has the potential to result in significant emissions reductions earlier than would have been achieved by the periodic monitoring requirements. The EPA therefore believes that the super-emitter response program is a reasonable addition as part of the BSER for fugitive components because the program would only target particularly large emission events (measuring over 100 kg/hr) from these affected or designated facilities and would not require any action for smaller emissions events that would be addressed by the periodic monitoring.

We have considered the costs of adding the super-emitter response program as an additional work practice standard to the periodic monitoring and repair requirements for addressing fugitive emissions and concluded that the cost is reasonable. First, owners and

operators do not bear the cost of monitoring and detecting super-emitter emissions events, which would be conducted by EPA-approved qualified third parties. Instead, as discussed in more detail below, the first step of the program would be for owners and operators to investigate and identify the source(s) of a super-emitter emissions event upon receiving reliable information. Since owners and operators would already have to perform this task for purposes of the compliance assurance measure for other affected facilities and associated control devices under the super-emitter response program, described above, there would be little additional cost in including this same root-cause analysis as part of the fugitive emissions work practice standards. Second, to the extent a root-cause analysis reveals that the super-emitter emissions event is caused by a fugitive emissions component, there may be no additional cost associated with their repair, since these fugitive emissions might be detected and repaired during the next scheduled periodic monitoring; the super-emitter response program would simply require such repair to occur sooner. In other words, for super-emitter emissions events identified as resulting from fugitive emissions components between scheduled monitoring surveys, the proposed super-emitter response program would provide an opportunity for repairs sooner than the next scheduled survey, thus resulting in fewer emissions overall from the event.

Moreover, even if there are costs associated with the investigation and mitigation, the threshold for identifying a super-emitter emissions event is so high that it ensures that the emissions reductions achieved by the mitigation are cost-effective. In other words, it is reasonable to conclude that these actions would be cost-effective in light of the large mass rate of emissions (100 kg/hr of methane or greater) that would be reduced, and the high volume of gas saved. It is highly unlikely that these actions would exceed the \$2,185/ton of methane reduced, which is the highest value we have determined to be cost effective for reducing methane from sources within this source category.

In summary, the EPA finds the data demonstrate that the super-emitter response program is cost-effective, even though the EPA recognizes that the total emissions reductions that will result from the program are difficult to quantify. By definition, a super-emitter emissions event emits more than 100 kg of methane/hour, which means that an on-going super-emitter emissions event that lasts an extended period may emit

more than 2.5 tons of methane in a day, and potentially almost 80 tons if it continued undetected for a month. Applying the same social cost of methane values used to develop the estimates in Table 5 above, such an event could generate over \$100,000 in avoidable climate damages.¹¹⁵ The proposed fugitive emissions monitoring and repair requirements for facilities with major production and processing equipment, discussed in section IV.A, are cost-effective when they are projected to reduce 10.85 tpy of methane. A super-emitter emissions event may emit almost twice that, or in some cases substantially more, in a single week. In addition, the cost of most of the repairs that would be necessary to respond to a super-emitter emissions event may be achieved at very low additional cost because the need for repair would be discovered at the next required inspection, indicating that most repairs in response to super-emitter emissions events may be simply moving the repairs earlier in time. Furthermore, halting super-emitter emissions events recovers natural gas for sale that would otherwise be emitted to the atmosphere, so it is possible that for many super-emitter emissions events identified, the revenues from recovered natural gas may offset a significant portion of the costs of repair incurred by the owner or operator. For all these reasons, the EPA finds the super-emitter response program cost-effective. Because the costs of this program incurred by owners and operators, the length of time over which these events occur, and the emissions reductions that may be achieved have uncertainties associated with them, the EPA solicits comments on the various factors related to the cost-effectiveness of the super-emitter response program, including any information further detailing the costs and emissions reductions of this program. Specifically, the EPA solicits comments on any relevant data, appropriate methodologies, or reliable estimates to help quantify the costs, emissions reductions, benefits, and potential distributional effects of this program (including, for example, benefits for communities with EJ concerns). We also take comment on how to improve the accuracy of our estimates of baseline emissions levels, emissions reduction opportunities, and the frequency and intensity of super-emitter events, and how to incorporate

any recent, reliable estimates of methane emissions.

c. Additional Solicitations for Comment

While the EPA is proposing a general framework for the super-emitter response program, there are several additional aspects of the program for which we are soliciting additional information and comment. These solicitations are described in the following paragraphs.

First, the EPA is soliciting comment on the mechanism for identifying the owners and operators to receive the super-emitter emissions event notifications. Entities approved to make such notifications need a way to identify to whom they should be sent and how to assure they are received. The EPA specifically seeks comment on what mechanisms exist to make such identifications now, the reliability, accuracy, and timeliness of those mechanisms, and the difficulty or cost of accessing those mechanisms.

The EPA is also soliciting comment on the amount of time allowed for notifications following detection of a super-emitter emissions event. Clearly, timely notification of the event is essential to maximize the emission reduction potential from the event, but it is the EPA's understanding that each technology or remote measurement method experiences a lag between when a survey is conducted and when the data has been analyzed to demonstrate emissions were present. The EPA is soliciting comment on what deadline for notifications following detection survey is most advantageous and feasible given current data analysis requirements for remote measurement technologies and methods. Further, time will be required to properly identify the relevant owner or operator of the site. One factor is that ownership of sites can change frequently, or specific contacts may move into other roles or leave the company. Therefore, the EPA is soliciting comment on the amount of additional time that should be factored into the notification process to account for this identification step.

D. Pneumatic Controllers

Pneumatic controllers are devices used to regulate a variety of physical parameters, or process variables, often using air or gas pressure to control the operation of mechanical devices, such as valves. The valves, in turn, control process conditions such as levels, temperatures and pressures. When a pneumatic controller identifies the need to alter a process condition, it will open or close a control valve. In many situations across all segments of the Oil

and Natural Gas Industry, pneumatic controllers make use of the available high-pressure natural gas to operate or control the valve. In these "natural gas-driven" pneumatic controllers, natural gas may be released with every valve movement (intermittent) and/or continuously from the valve control. Detailed information on pneumatic controllers, including their functions, operations, and emissions, is provided in the preamble for the November 2021 proposal (86 FR 63202–63203; November 15, 2021).

1. NSPS OOOOb

a. November 2021 Proposal

In the November 2021 proposal, a pneumatic controller affected facility was defined as each single natural gas-driven pneumatic controller, whether the controller was a continuous bleed controller or an intermittent vent controller. This affected facility definition would have applied at sites in all segments of the oil and natural gas source category. We proposed the requirement that all controllers (continuous bleed and intermittent vent) have a VOC and methane emission rate of zero. The proposed rule did not specify how this emission rate of zero was to be achieved, but a variety of viable options were discussed. These options included the use of pneumatic controllers that are not driven by natural gas such as instrument air-driven pneumatic controllers and electric controllers, as well as natural gas-driven controllers that are designed so that there are no emissions, such as self-contained pneumatic controllers. Because we proposed to define an affected facility as each pneumatic controller that is driven by natural gas and that emits to the atmosphere, pneumatic controllers not driven by natural gas would not have been affected facilities. Controllers that are driven by natural gas but that do not emit to the atmosphere would not have been affected facilities either, according to the November 2021 proposed definition.

The November 2021 proposed rule included an exemption from this zero-emission standard for pneumatic controllers at sites in Alaska that do not have access to electrical power. For these sites, the proposed rule would have required the use of low-bleed, continuous bleed controllers. It would also have required that intermittent vent controllers not vent during idle periods and that periodic inspections be performed on these controllers to ensure that such venting does not occur.

¹¹⁵ This damage estimate assumes a social cost of methane estimate of at least \$1,400 per metric ton of methane, which is less than the interim estimate that EPA uses in the RIA for a 3% discount rate for the first year that the proposed NSPS OOOOb is assumed to go into effect (2023).

b. Changes to Proposal and Rationale

The proposed NSPS OOOOb requirements in this supplemental proposal differ from the November 2021 proposal in several ways, starting with the affected facility definition. As noted above, the pneumatic controller affected facility definition proposed in November 2021 was each individual natural gas-driven pneumatic controller. In this supplemental proposal, a pneumatic controller affected facility is defined as the collection of all the natural gas-driven pneumatic controllers at a site.

Another change from the November 2021 proposal is that two specific types of natural gas-driven controllers that were proposed to be excluded from the affected facility definition are now proposed to be included. These are: (1) Controllers where the emissions are collected and routed to a gas-gathering flow line or collection system to a sales line, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve (*i.e.*, generally characterized as “routing to a process”); and (2) self-contained natural gas pneumatic controllers.

There is no change to the fundamental proposed standard for pneumatic controllers, which is that all pneumatic controllers would be required to have a methane and VOC emission rate of zero. The proposed standard does include requirements for the two specific types of natural gas-driven controllers identified above. These controllers do not emit methane or VOC from routine operations. However, since they are powered by natural gas, the potential for emissions exists if they are not maintained and operated properly. For instance, a self-contained controller could malfunction or develop leaks, or a CVS that is routing the controller emissions to a process could develop leaks. Therefore, the proposed rule includes requirements to avoid such situations so that the controllers have zero direct emissions. Since routing to a process includes the option of using the natural gas captured for use as a fuel source, emissions would occur downstream at the engine, generator, or process heater resulting from the combustion of the natural gas from the controllers. However, these emissions are replacing those that would have resulted from the combustion of fuel gas, meaning that the net result is still zero direct emissions.

While the BSER conclusion did not change from the November 2021 analysis, the EPA did update the analysis based on information received

in the public comments, including an analysis of potential alternative standards for small sites with few pneumatic controllers.

Details on the proposed pneumatic controller requirements in this supplemental proposal are provided below in section IV.D.1.c. The following sections provide the rationale for the changes discussed above, a discussion of other related issues raised by commenters, and the updated BSER analysis.

i. Affected Facility, Modification, and Reconstruction

As noted above, the pneumatic controller affected facility definition changed from being based on a single continuous bleed or intermittent vent controller in the November 2021 proposal to the collection of natural gas-driven continuous bleed and intermittent vent controllers at a site in this supplemental proposal.¹¹⁶ The EPA is proposing this change based on the consistent recommendation of numerous commenters, particularly commenters from the oil and natural gas industry. Several comments on the November 2021 proposal noted the disconnect between the pneumatic controller affected facility definition (*i.e.*, an individual controller) and the cost analysis, which was based on the replacement of all pneumatic controllers with zero-emitting devices at a site.¹¹⁷ One commenter pointed out the complexities of tracking and managing the universe of pneumatic controllers at a site when some are affected facilities and others are not, and recommended that the EPA propose a simpler and more robust system.¹¹⁸ Another commenter indicated that defining the affected facility on a site-wide basis aligns with how emissions from pneumatic controllers will likely be handled by owners and operators of oil and natural gas facilities. This commenter opined that defining the pneumatic controller affected facility on a single controller basis, as opposed to as the collection of all controllers at a site, would be unnecessarily

burdensome.¹¹⁹ A separate commenter discusses the fact that converting a single pneumatic controller to a zero-emitting device typically requires a conversion of all controllers at the facility to zero-emitting devices.¹²⁰

We agree with the commenters that defining the pneumatic controller affected facility as the collection of all controllers at a site is the most practical approach. Significantly, most of the zero-emissions measures for pneumatic controllers are site-wide solutions. For instance, a compressed air system installed at a site would be used to power all of the pneumatic controllers at the site, rather than a separate system for each controller. Similarly, a solution based on solar energy would likely utilize a single array of solar panels to provide power to all the controllers at the site. In fact, as pointed out by the commenters, the analysis for the November 2021 proposed rule was conducted on a “model plant” site-wide basis. As noted above, the comments that the EPA received on the pneumatic controller affected facility definition in the November 2021 proposal all advocated for a change in the definition from a single controller to the collection of all onsite pneumatic controllers. However, the EPA did not specifically solicit comment on the particular question of how to define the affected facility in November. Now that the EPA is proposing in this supplemental proposal to define the affected facility as the collection of natural gas-driven continuous bleed and intermittent vent controllers at a site, the EPA solicits comment on the proposed changed definition.

Under the previous approach of treating each controller on an individual basis, the installation or replacement of a pneumatic controller would have resulted in that singular controller being a new source and an affected facility subject to NSPS OOOOb. Under this supplemental proposal approach to treat the collection of all controllers at a site as the affected facility, clear descriptions of modification and reconstruction are needed in order to indicate when an existing collection of controllers would become subject to NSPS OOOOb. In 40 CFR 60.14(a), a “modification” is defined as “any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant.” To clarify what constitutes a modification for the

¹¹⁶ The EPA notes that there are other sources of emissions in this supplemental proposed rule that the EPA proposes to regulate as a collection of emissions sources, rather than as individual emission units. Namely, the EPA proposes to define tank batteries as the group of all storage vessels that are manifolded together for liquid transfer and proposes to define fugitive emissions components as the collection of fugitive emissions components at all well sites.

¹¹⁷ See Document ID Nos. EPA-HQ-OAR-2021-0317-0599, EPA-HQ-OAR-2021-0317-0808, EPA-HQ-OAR-2021-0317-0831, and EPA-HQ-OAR-2021-0317-0777.

¹¹⁸ See Document ID No. EPA-HQ-OAR-2021-0317-0742.

¹¹⁹ See Document ID No. EPA-HQ-OAR-2021-0317-0817.

¹²⁰ See Document ID Nos. EPA-HQ-OAR-2021-0317-0808.

collection of all controllers at a site, the supplemental proposed rule specifies that if one or more pneumatic controllers is added to the site, such addition constitutes a modification and the collection of pneumatic controllers at the site becomes a pneumatic controller affected facility. This is because the addition of a controller represents a physical change to the site and would result in an increase in emissions from the collection of controllers. Based on information provided by industry commenters, the EPA believes that owners and operators will implement zero-emissions controllers across a site when a modification occurs because converting a single pneumatic controller to a zero-emitting device typically requires converting all controllers at the facility to zero-emitting devices. The EPA solicits comment on the ways in which a modification to a pneumatic controller affected facility would occur in light of the affected facility definition proposed herein, which includes the collection of all natural gas-driven continuous bleed and intermittent vent controllers at a site.

In 40 CFR 60.15(b), “reconstruction” is defined as the replacement of components of an existing facility “to such an extent that the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility,” and “it is technologically and economically feasible to meet the applicable standards.” The proposed pneumatic controller affected facility definition for this supplemental proposal is the collection of all natural gas driven controllers at a site; therefore, the cost that would be required to construct a “comparable entirely new facility” would be the cost of replacing all existing controllers with new controllers. Because individual controllers are likely to have comparable replacement costs, it is reasonable to assume that there would be a one-to-one correlation between the percentage of controllers being replaced at a site and the percentage of the fixed capital cost that would be required to construct a comparable entirely new facility. Accordingly, we are proposing to include a second, simplified method of determining whether a controller replacement project constitutes reconstruction under 40 CFR 60.15(b)(1) whereby reconstruction may be considered to occur whenever greater than 50 percent of the number of existing onsite controllers are

replaced.¹²¹ The EPA believes that allowing owners or operators to determine reconstruction by counting the number of controllers replaced is a more straightforward option than requiring owners and operators to provide cost estimate information. By providing this option, the EPA intends to reduce the administrative burden on owners and operators, as well as on the implementing agency reviewing the information. Owners and operators would be able to choose whether to use the cost-based criterion or the proposed number-of-controllers criterion. No matter which option an owner or operator chooses to use, the remaining provisions of 40 CFR 60.15 apply—namely, 40 CFR 60.15(a), the technological and economical provision of 40 CFR 60.15(b)(2), and the requirements for notification to the Administrator and a determination by the Administrator in 40 CFR 60.15(d), (e) and (f). The EPA is proposing that the standard in 40 CFR 60.15(b)(1) specifying that the “fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility” can be met through a showing that more than 50 percent of the number of existing onsite controllers are replaced. Therefore, upon such a showing, an owner or operator may demonstrate compliance with the remaining provisions of 40 CFR 60.15 that reference the “fixed capital cost” criterion. The EPA solicits comment on its proposal to add an option for owners or operators to use in determining whether reconstruction occurs by showing the number of components replaced. The EPA reiterates that this proposed option would supplement the existing option of determining replacements by fixed capital cost, as set forth in 40 CFR 60.15.

A second factor for consideration in the reconstruction of an existing pneumatic controller affected facility is during what time period the number of controllers replaced or the fixed capital cost of the new components should be aggregated. Consider the following scenario: an owner first seeks to replace 30 percent of the pneumatic controllers of an existing facility and then, shortly after commencing or completing those replacements, the owner seeks to replace an additional 30 percent. The owner would have replaced 60 percent

of its controllers in total, and presumably, the fixed capital cost of those two replacement programs would be approximately 60 percent of the fixed capital cost that would be required to construct a comparable entirely new facility. It is unclear under the language of 40 CFR 60.15(d) whether this owner should be deemed to have proposed two distinct replacement programs or instead a single replacement program. The EPA believes that such a stepwise controller replacement program should not be used by facilities undergoing numerous replacement programs close in time to avoid compliance with the NSPS. Failure to regulate these sources would undermine Congress’ intent that air quality be enhanced over the long term with the turnover of polluting equipment, and with the intent of the EPA’s reconstruction provisions, which are triggered where an existing facility replaces its components “to such an extent that it is technologically and economically feasible for the reconstructed facility to comply with the applicable standard of performance.”¹²² Where a number of controllers are replaced relatively close in time such that the aggregate costs or number of controllers is greater than 50 percent, the EPA proposes to conclude that it is reasonable to treat those replacements as part of a continuous program of controller replacement for purpose of determining reconstruction.

In order to clarify how the regulatory language in 40 CFR 60.15 would apply to the replacement of pneumatic controllers, we are proposing that where an owner or operator applies the definition of reconstruction in § 60.15(b)(1), reconstruction occurs when the fixed capital cost of the new pneumatic controllers exceeds 50 percent of the fixed capital cost that would be required to replace all the pneumatic controllers at the site. The “fixed capital cost of the new pneumatic controllers” includes the fixed capital cost of all pneumatic controllers which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year rolling period.¹²³

¹²² See Modification, Notification, and Reconstruction, 40 FR 58,417 (December 16, 1975) (also stating that “the purpose of the reconstruction provision is to recognize that replacement of many of the components of a facility can be substantially equivalent to totally replacing it at the end of its useful life with a newly constructed affected facility.”).

¹²³ As noted above, incorporating a set period of time within which numerous component replacements amount to “reconstruction” is in accordance with 40 CFR 60.15(g), which provides that “[i]ndividual subparts of this part

¹²¹ Adding this method of determining “reconstruction” for pneumatic controllers is in accordance with 40 CFR 60.15(g), which states that “[i]ndividual subparts of this part [“Reconstruction”] may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.”

Thus, the EPA will count toward the greater than 50 percent reconstruction threshold all controllers replaced pursuant to all continuous programs of controller replacement which commence within any 2-year rolling period following proposal of these standards. If the owner or operator applies the definition of reconstruction based on the percentage of pneumatic controllers replaced, reconstruction occurs when greater than 50 percent of the pneumatic controllers at a site are replaced. The percentage includes all pneumatic controllers which are or will be replaced pursuant to all continuous programs of pneumatic controller replacement which are commenced within any 2-year rolling period.

In the Administrator's judgment, the 2-year rolling period provides a reasonable method of determining whether an owner of an oil and natural gas site with pneumatic controllers is actually proposing extensive controller replacement, within the EPA's original intent in promulgating 40 CFR 60.15. The EPA solicits comment on this proposed 2-year rolling aggregation period for all continuous programs of pneumatic controller and pneumatic pump replacement (see section IV.E.b.i. for a discussion of proposing the same approach for determining reconstruction for pneumatic pumps). The EPA is particularly interested in comments regarding whether this approach will make it easier for owners and operators to determine reconstruction at their sites, whether using a set time frame is reasonable and feasible to put into practice, whether two years is an appropriate timeframe, and whether a rolling basis for the two-year time frame is a reasonable calculation (for example, see Scenario 5 below). The EPA is also interested in understanding how frequently controllers and pumps are typically replaced.

["Reconstruction"] may include specific provisions which refine and delimit the concept of reconstruction set forth in this section." In addition, the EPA notes that numerous NSPS and EG regulatory provisions incorporate a 2-year time period into the definition of reconstruction. *See, e.g.,* Standards of Performance for New Stationary Sources; Bulk Gasoline Terminals, 48 FR 37582–83 (August 18, 1983) (explaining need for a fixed period within which to determine reconstruction when component replacement occurs over time and determining that two years is reasonable); 40 CFR 60.506(b) (codifying reconstruction definition to include such a time period for bulk gasoline terminals (40 CFR part 60, subpart XX)). *See also* 40 CFR 60.383(b) (metallic mineral processing plants (subpart LL)); 40 CFR 60.100(f), 60.100a(d) (petroleum refineries (40 CFR part 60, subparts J and Ja)); 40 CFR 60.706(a) (volatile organic compound emissions from synthetic organic chemical manufacturing industry reactor processes (40 CFR part 60, subpart RRR)).

The following are example scenarios of the application of these proposed requirements for a site with 15 natural gas-driven pneumatic controllers. Scenario 1: One of the controllers is to be replaced (at any given time). The collection of controllers at the site would not become a pneumatic controller affected facility because the emissions from the collection of controllers would not be increased (so such action does not constitute a modification). Also, such action would not constitute reconstruction because the fixed capital cost of the replacement of this single controller would not equal 50 percent or greater of the fixed capital cost that would be required to replace all the controllers in the affected facility. Scenario 2: Eight of the controllers are to be replaced at the same time. This would represent reconstruction (because more than 50 percent of the total are being replaced which means that the fixed capital cost of the replacement would exceed 50 percent of the fixed capital cost that would be required to replace all the controllers in the affected facility), so the 15 controllers (*i.e.*, the "collection" of controllers at the site) would become a pneumatic controller affected facility. This affected facility would then be subject to the zero-emissions standard, meaning that all controllers at the site, including the eight new controllers and the seven existing controllers, must comply with a methane and VOC emission rate of zero. Scenario 3—six of the pneumatic controllers are replaced in January and seven more controllers are replaced the following April (15 months later). This would represent reconstruction because more than 50 percent of the total number of controllers are being replaced over a 2-year period, so the 15 controllers (*i.e.*, the "collection" of controllers at the site) would become a pneumatic controller affected facility at the time the seven controllers were replaced in April. This affected facility would then be subject to the zero-emissions standard, meaning that all controllers at the site must comply with a methane and VOC emission rate of zero. Scenario 4: An additional pneumatic controller is added at any given time. This would represent a modification since it would constitute a physical change and would result in an increase in emissions. The 16 controllers would represent a pneumatic controller affected facility and all would need to comply with a methane and VOC emission rate of zero. Scenario 5: replacement of four of the pneumatic controllers is commenced in January in year 1; replacement of two

more controllers is commenced the following April in year 2 (15 months later); replacement of two more is commenced the following March in year 3 (26 months after the initiating replacement in January); and replacement of four more is commenced that August of year 3 (31 months after initiating replacement in January). Only six controllers of the 15 controllers were replaced in the discrete two-year time period that began in January of year 1, and therefore would not meet the proposed reconstruction definition. However, when considered on a rolling 2-year basis, eight of the 15 controllers were replaced over years 2 and 3, which would meet the proposed reconstruction definition. EPA specifically solicits comment on whether the two-year time frame should be implemented on a rolling basis or as a discrete time period.

The EPA also solicits comment on whether it would be appropriate to apply either of the two elements of reconstruction that the EPA is proposing for pneumatic controllers (and pneumatic pumps, as described in section IV.E.) to any other affected facility in NSPS OOOOb and EG OOOOc. Specifically, the EPA is interested in comments regarding whether any other source category would benefit from either: 1) adding an option to determine reconstruction based on the number of components replaced (in addition to the existing option of determining replacements by fixed capital cost, as set forth in 40 CFR 60.15), and/or 2) setting a specific time period within which replaced components will be aggregated toward the greater than 50 percent replacement threshold (assessed either by number or cost), *e.g.*, any two-year period beginning when a continuous program of component replacement commences.

Commenters stated that the EPA should allow like-kind replacement of existing individual controllers without causing the controller to become an affected facility under NSPS OOOOb.¹²⁴ The commenters indicated that if the EPA were to not allow this, operators who are voluntarily replacing high-bleed natural gas-driven controllers with low-bleed controllers would likely stop doing so. The EPA's proposed change to a site-wide pneumatic controller affected facility definition would allow the replacement of existing high-bleed controllers with low-bleed controllers without becoming an affected facility, provided that 50

¹²⁴ See Document ID Nos. EPA–HQ–OAR–2021–0317–0817 and EPA–HQ–OAR–2021–0317–0831.

percent or less of the controllers are replaced at the same time.

Commenters also encouraged the EPA to provide an exemption for “temporary sources.” One commenter provided the example where an operation may require use of temporary or portable equipment for a short period of time (*i.e.*, less than 180 days) where it may not be possible to connect to the grid or route to an onsite control device.¹²⁵ Another commenter indicated that non-emitting¹²⁶ requirements are not justified for short term controller usage related to a non-stationary source, and exemption of controllers on temporary equipment is consistent with state regulations proposed in New Mexico and finalized in Colorado. The commenter indicated that the EPA should also make it clear that the requirements for pneumatic controllers are not applicable during drilling or completion.¹²⁷

The EPA acknowledges that the focus of the BSER analysis has been on stationary sources and pneumatic controllers that are part of the routine operation of oil and natural gas facilities. Although some type of alternative approach may be warranted for pneumatic controllers associated with temporary operations, we lack sufficient information to include an exemption, or perhaps alternative standards, for pneumatic controllers associated with temporary equipment. Therefore, the EPA is requesting more information on these situations. The EPA would like specific examples of when temporary equipment is utilized, the function of the controllers during this time, how they are powered, and

the typical duration of their usage. The EPA also requests information explaining in detail why the zero-emission solutions that are used for the permanent equipment at the site cannot be also utilized for this temporary equipment.

Another change to the affected facility definition in this supplemental proposal is that natural gas-driven controllers from which all emissions are collected and routed to a process, as well as self-contained natural gas-driven pneumatic controllers, are not excluded from the pneumatic controller affected facility definition. The EPA is proposing to include these types of natural gas driven controllers because they are driven by natural gas. While the EPA understands that these controllers have zero routine emissions from the operation of the device and are therefore compliant with the proposed standard when they are properly operated and maintained, they do have the potential to emit methane and VOC if they are not operated and maintained properly. Therefore, we are proposing that natural gas-driven controllers from which all emissions are collected and routed to a process, as well as self-contained natural gas-driven pneumatic controllers (which release gas into the downstream piping and not to the atmosphere), are part of a pneumatic controller affected facility, and therefore subject to the zero methane and VOC emissions standards. Specifically, the proposed rule would require that owners and operators ensure proper maintenance and operation of the controllers. For natural gas-driven controllers from which all emissions are collected and routed to a process, the CVS collecting and routing the emissions to the process must comply with the CVS no identifiable emissions requirements in proposed 40 CFR 60.5411b, paragraphs (a) and (c). Self-contained controllers would be required to be designed and operated with no identifiable emissions, as demonstrated by initial and quarterly inspections using optical gas imaging and any necessary corrective actions.

NSPS OOOOa exempts controllers from the standards for functional needs, “including but not limited to response time, safety, and positive actuation.” 40 CFR 60.6390a(a). The November 2021 proposed rule did not include these functional needs exemptions, except for locations in Alaska that did not have access to electrical power. The NSPS OOOOa exemptions were based on the use of a low-bleed natural gas driven pneumatic controller. Because the November 2021 proposed standard would not have allowed the use of natural-gas driven controllers, the EPA

did not believe that this exemption was needed.

Several commenters requested that the NSPS OOOOa functional needs exemptions be included in NSPS OOOOb in their entirety, while other commenters indicated that they should only be allowed in very limited instances and only when justification is provided in an annual report. Commenters consistently raised the need to utilize natural gas-driven pneumatic controllers associated with emergency shutdown devices (ESDs). One commenter explained that an ESD is designed to minimize consequences of emergency situations and will only emit in certain isolated circumstances, such as if a well must be shut in. A large change in pressure is required to actuate an ESD, which may not be deliverable in a sufficient time by a compressed air or electric controller. Furthermore, if power is lost, these devices must still be able to function. It is rare that ESDs are activated, and their emissions impact is minimal, but their functional need is necessary and critical to safe operations. The commenter noted that both the current version of the proposed rule in New Mexico and finalized regulations in Colorado offer similar exemptions for ESDs.¹²⁸

The EPA still believes that the overall functional needs exemption is not necessary, as the limitations inherent in low-bleed natural gas-driven controllers are not present in many of the zero emissions options, particularly compressed air. The EPA also notes that any natural gas-driven controller is allowed, whether low or high-bleed, if the emissions are collected and routed to process in a manner that achieves zero methane emissions.

The EPA recognizes the important function of natural gas-driven controllers for ESDs. Rather than including such devices in the affected facility, the EPA is proposing to specifically exclude them from the affected facility definition.

Relatedly, one commenter requested that the EPA allow companies the option to continue to use, or install, a dual natural gas system as a backup for key controller functions. Such a natural gas backup system would be used in the case of electrically actuated controller failure, loss of power, or other contingencies.¹²⁹ Another commenter added that if the zero-emissions system (*i.e.*, instrument air) goes down, there is no provision within the proposed rule

¹²⁵ See Document ID No. EPA-HQ-OAR-2021-0317-0831.

¹²⁶ The terms “zero emissions” and “non-emitting” are used to describe pneumatic controllers. In Colorado, 5 Code of Colorado Regulations (CCR) Regulation 7, Part D, Section III, defines a “non-emitting” controller as “a device that monitors a process parameter such as liquid level, pressure or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to: no-bleed pneumatic controllers, electric controllers, mechanical controllers and routed pneumatic controllers.” A routed pneumatic controller is defined as “a pneumatic controller that releases natural gas to a process, sales line or to a combustion device instead of directly to the atmosphere.” The EPA is proposing that pneumatic controllers must be “zero emission” controllers. The difference in non-emitting, as defined by Colorado and as used by the commenter, and zero emissions, as proposed in this action, is that pneumatic controllers for which emissions are captured and routed to a combustion device are not considered to be “zero emission” controllers. Therefore, routing to a combustion device is not an option for compliance with the proposed NSPS OOOOb.

¹²⁷ See Document ID No. EPA-HQ-OAR-2021-0317-0808.

¹²⁸ See Document ID No. EPA-HQ-OAR-2021-0317-0808.

¹²⁹ See Document ID No. EPA-HQ-OAR-2021-0317-0817.

to allow for the temporary use of natural gas. The commenter urged the EPA to evaluate the reliability and availability of such systems that would be deployed at such breadth.¹³⁰ The EPA is interested in understanding these backup systems more fully. In particular, the EPA is requesting information on these systems regarding how frequently and for how long these systems are used or would be expected to be used. The EPA is concerned that allowing these backup systems would result in a potential loophole that would enable owners or operators to continue to use natural gas-driven controllers in routine situations. Therefore, the EPA is interested in how the use of these systems could be narrowly defined and how a clear distinction could be drawn between the allowed use of these backup systems and violations of the zero emissions standard.

ii. BSER Analysis

Based on comments received on the November 2021 BSER analysis and updated information provided, the EPA

revised the BSER analyses for this supplemental proposal for pneumatic controllers for the production and transmission and storage segments of the industry. The following paragraphs describe the updated information, the changes to the BSER analyses, and the updated results. The analysis for natural gas processing plants, which can be found in the TSD for the November 2021 proposal, was not updated.

Several commenters objected to the emission factors that were used for the analysis. One commenter stated that the emission factors used in the GHGRP petroleum and natural gas source category (40 CFR part 98, subpart W, also referred to as “GHGRP subpart W”) for pneumatic controllers were developed in the 1990’s and that they may no longer be applicable considering technological improvements.¹³¹ Another commenter indicated that the factors used underestimated emissions and that recent research indicates that actual average emissions from pneumatic controllers may be higher than estimated.¹³²

The emissions factors used for the November 2021 BSER analysis for the production segment were from a recent study conducted by the American Petroleum Institute (API).¹³³ The factors for the transmission and storage segment were from Table W–3B of GHGRP subpart W (2021). Since the November 2021 proposal, the EPA has conducted a comprehensive review of available information related to emissions from natural gas-driven pneumatic controllers and has proposed to update the emission factors in GHGRP subpart W to reflect this research (87 FR 36920; June 21, 2022). The EPA concluded that these results are the most appropriate for use in this BSER analysis. The information evaluated for the June 2022 proposed revisions to GHGRP subpart W included the API study. Table 22 provides the emission factors used for the November 2021 analysis and those used for the updated analysis in this supplemental proposal.

TABLE 22—NATURAL GAS-DRIVEN PNEUMATIC CONTROLLER EMISSION FACTORS FOR THE PRODUCTION AND TRANSMISSION AND STORAGE SEGMENTS

Segment/type of controller	Emissions (scf whole gas/hr)	
	2022 Updated analysis	November 2021 analysis
Production:		
Low bleed	6.8	2.6
High bleed	21.2	16.4
Intermittent vent	8.8	9.2
Transmission and Storage:		
Low bleed	6.8	1.37
High bleed	32.4	18.2
Intermittent vent	2.3	2.35

As can be seen in Table 22, the emissions factors for low-bleed and high-bleed increased from those used for the November 2021 analysis, while the intermittent vent factors decreased slightly.

One commenter indicated that while they appreciated that the EPA utilized emission factors from the API’s Field Measurement Study, they believed that the use of the average intermittent pneumatic device vent rate was incorrect in this application.¹³⁴ They stated that under this proposal, any intermittent device would be monitored routinely and repaired or replaced if malfunctioning, so the more appropriate emission factor is 0.28 scf whole gas/

controller-hour, not the average emission factor of 9.2 scf whole gas/controller-hour that the EPA used in the November 2021 proposal. The commenter noted that the average emission factor should only be used for controllers that are not routinely monitored as part of a proactive monitoring and repair program or where the monitoring status is unknown. The commenter stated that the normal operation emission factor should be applied to controllers that are found to be operating normally as part of a proactive monitoring and repair program and contended that this approach achieves a nearly similar level

of emission reduction for much less investment by operators.

The EPA agrees with the commenter that the lower emission factor is appropriate to represent the emissions level for intermittent vent controllers that are routinely monitored as part of a proactive monitoring and repair program. While the EPA recognizes that some companies have voluntarily implemented such programs, we do not have information to suggest that the majority of the intermittent vent controllers in operation are part of such a program. The average emission factor that the EPA used considers those low-emitting properly operating controllers, as well as those that are not operating

¹³⁰ See Document ID No. EPA–HQ–OAR–2021–0317–0599.

¹³¹ See Document ID No. EPA–HQ–OAR–2021–0317–0749.

¹³² See Document ID No. EPA–HQ–OAR–2021–0317–0918.

¹³³ “API Field Measurement Study: Pneumatic Controllers EPA Stakeholder Workshop on Oil and

Gas.” November 7, 2019—Pittsburg PA. Paul Tupper.

¹³⁴ See Document ID No. EPA–HQ–OAR–2021–0317–0808.

properly and that are venting during idle. The EPA finds that this average factor is the correct factor to represent the “uncontrolled” emissions from the universe of intermittent vent controllers.

One commenter noted that all three sizes of model plants (small, medium, large) contained one high-bleed natural gas-driven controller. The commenter indicated that some state regulations do

not allow for the use of high-bleed controllers and concluded that the EPA’s baseline emissions analysis was likely skewed high.¹³⁵

The EPA agrees with this commenter. In addition to state regulations that do not allow the use of high-bleed controllers, in the absence of NSPS OOOOb, NSPS OOOOa would not allow the installation of high-bleed controllers

at new sites. Therefore, in the updated analysis for new sources, the EPA did not include any high-bleed controllers in any of the model plants. Table 23 provides a summary of the pneumatic controller model plants and emissions. The emissions shown consider the changes in the emission factors provided above in Table 22.

TABLE 23—SUMMARY OF PNEUMATIC CONTROLLER MODEL PLANTS FOR NEW SOURCES

Segment/model plant	November 2021 analysis					2022 updated analysis				
	Number of controllers			Emissions (tpy)		Number of controllers			Emissions (tpy)	
	HB ^a	LB ^a	INT ^a	CH ₄	VOC	HB ^a	LB ^a	INT ^a	CH ₄	VOC
Production:										
Small	1	1	2	5.7	1.6	0	2	2	4.7	1.3
Medium	1	1	6	11.2	3.1	0	2	6	10.0	2.8
High	1	4	15	24.9	6.9	0	5	15	25.1	7.0
Trans/Storage:										
Small	1	1	2	4.1	0.1	0	2	2	3.1	0.09
Medium	1	1	6	5.7	0.2	0	2	6	4.6	0.1
High	1	4	15	10.0	0.3	0	5	15	11.6	0.3

^aHB—continuous high bleed, LB—continuous low bleed, INT—intermittent vent.

Some commenters also disagreed with the costs used for the BSER analysis. One commenter said that the EPA’s cost estimates were taken directly from the 2016 White Paper¹³⁶ and that the EPA did not update the cost numbers for zero-emission electronic controllers, solar panels, or batteries.¹³⁷ The EPA notes that the primary basis for the costs used for the November 2021 analysis was not the White Paper, but rather a 2016 report by Carbon Limits, a consulting company with longstanding experience in supporting efficiency measures in the petroleum industry.¹³⁸ One commenter¹³⁹ pointed out that Carbon Limits updated their report in early 2022,¹⁴⁰ and recommended that the EPA utilize the more recent information in that report since it included more up-to-date research on zero emissions options for pneumatic controllers. We reviewed the updated 2022 Carbon Limits report and we agree with the commenter that the information presented is well researched and representative of the costs of zero-emission pneumatic controller technologies.

In addition to updating the analysis to reflect the information in the 2022 Carbon Limits report, we also increased

the estimate of installation costs and considered operation and maintenance costs for all types of pneumatic controller systems not driven by natural gas.

One commenter mentioned that for zero emission, electrical controller setups, skilled electrical labor is required for wiring, programming, and tuning, which cannot be conducted by lease operators that would otherwise manage this equipment. According to the commenter, one available estimate is as high as \$20,000 in labor costs per multi-well pad.¹⁴¹ In the November 2021 BSER analysis, we assumed that the installation and engineering costs were 20 percent of the total cost of the equipment. For the updated analysis, we increased those costs to 50 percent. The results were installation and engineering costs ranging from \$8,500 for a small electrical controller system to almost \$52,000 for a large instrument air system.

Another change to the capital cost estimate that the EPA made was to adjust the capital cost to represent the difference in the capital cost between the pneumatic controller system not driven by natural gas and the natural gas-driven controllers that would be

used in the absence of a zero emissions requirement. These costs, which were calculated based on \$2,227 equipment costs and the \$387 installation cost per pneumatic controller, were subtracted from the total capital investment of the pneumatic controller systems not driven by natural gas.

For the November 2021 analysis, the annual costs were estimated as the capital recovery of the original capital investment. This assumed that the operating and maintenance costs for a pneumatic controller system not driven by natural gas was the same as for natural gas-driven controllers. For this analysis, we took into account differences in operating costs. In general, the operating and maintenance costs for pneumatic controller systems not driven by natural gas is less than that of natural gas driven controllers, particularly if the gas is wet gas. To estimate the operating costs for natural gas-driven controllers, we used the average between the wet gas and dry gas cost from the 2022 Carbon Limits report. This resulted in a net savings in the annual operations and maintenance costs for electric and solar-powered controller systems. There are additional operating and maintenance costs

¹³⁵ See Document ID No. EPA-HQ-OAR-2021-0317-0749.

¹³⁶ U.S. EPA OAQPS. Oil and Natural Gas Sector Pneumatic Devices. Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel. April 2014.

¹³⁷ See Document ID No. EPA-HQ-OAR-2021-0317-0924.

¹³⁸ Carbon Limits. (2016) Zero emission technologies for pneumatic controllers in the USA—Applicability and cost effectiveness.

¹³⁹ See Document ID No. EPA-HQ-OAR-2021-0317-0844.

¹⁴⁰ Carbon Limits. (2022) Zero emission technologies for pneumatic controllers in the USA. Updated applicability and cost effectiveness.

Available at <https://cdn.catf.us/wp-content/uploads/2022/01/31114844/Zero-Emissions-Technologies-for-Pneumatic-Controllers-2022.pdf>.

¹⁴¹ See Document ID No. EPA-HQ-OAR-2021-0317-0749.

associated with instrument air systems, which resulted in an overall increase in these costs as compared to natural gas-driven controllers.

The costs for electric controllers and instrument air systems assume access to electrical power (that is, access to the grid). Solar-powered controllers can be utilized at remote sites that do not have access to electrical power. Instrument air systems can also be utilized at sites without access to the electricity grid, but these would require the installation and operation of a generator. These

generators could be powered by engines fueled by natural gas, diesel, or by solar energy. One commenter provided estimated costs ranging from \$60,000 to over \$200,000 for an instrument air system driven by a natural gas generator.¹⁴² Using the information provided by the commenter, the EPA estimated costs for the three model plants. Note that the largest model plant contained 20 controllers and the highest cost provided by the commenter was for a site with more than 200 controllers. Therefore, this cost was not utilized.

The EPA is specifically requesting more detailed information on the use of generators at sites without access to the grid to power pneumatic controllers, primarily to power instrument air systems. The EPA is also interested in receiving more information on the costs associated with this equipment. Table 24 provides the updated pneumatic controller systems not driven by natural gas costs. This table also provides the costs from the November 2021 analysis for comparison.

TABLE 24—TOTAL CAPITAL AND ANNUAL COSTS FOR PNEUMATIC CONTROLLER SYSTEMS NOT DRIVEN BY NATURAL GAS

Model plant	November 2021 analysis		2022 Updated analysis		
	TCI ^a	TAC ^b	TCI ^a	Adjusted TCI ^b	TAC ^c
Electric:					
Small System	\$25,494	\$2,799	\$25,742	\$15,287	\$762
Medium System	45,889	5,038	46,335	25,426	959
Solar:					
Small System	28,171	3,093	27,286	16,831	1,112
Medium System	51,242	5,626	49,424	28,515	1,679
Instrument Air System—Grid:					
Small System	not estimated	not estimated	57,966	47,512	9,285
Medium System	not estimated	not estimated	92,335	71,426	10,658
Large System	95,602	10,497	165,550	113,277	14,891
Instrument Air System—Natural Gas Generator:					
Small System	not estimated	not estimated	105,570	95,115	12,604
Medium System	not estimated	not estimated	121,240	100,231	11,914
Large System	not estimated	not estimated	242,850	190,577	19,565

^a TCI = Total capital investment includes capital cost of equipment plus engineering and installation costs.

^b Adjusted TCI = Total capital investment minus the cost that would have been incurred if natural gas-driven controllers had been installed.

^c TAC = Total annual costs including capital recovery (at 7 percent interest and 15-year equipment life) and operation and maintenance costs.

The controllers not driven by natural gas do not emit methane or VOC. Therefore, the emission reductions associated with these systems equal the total emissions shown above in Table 23. The estimated cost effectiveness values for the controllers not driven by natural gas are provided in Table 25. In

addition to the cost effectiveness values, Table 25 provides a conclusion regarding whether the estimated cost effectiveness value is within the range that the EPA has typically considered to be reasonable. The “overall” reasonableness determination is classified as “Y” if the cost effectiveness

of either methane or VOC is within the range that the EPA considers reasonable for that pollutant, or “N” if both the methane and VOC cost effectiveness values are beyond the range the EPA considers reasonable on a multipollutant basis.

TABLE 25—SUMMARY OF PNEUMATIC CONTROLLER SYSTEMS NOT DRIVEN BY NATURAL GAS COST EFFECTIVENESS FOR NEW SOURCES

Segment/model plant	Cost effectiveness (\$/ton) ^a —reasonable?				
	Single pollutant		Multipollutant		Overall ^a
	Methane	VOC	Methane	VOC	
Production:					
Small—Electric controllers—grid	\$162–Y	\$581–Y	\$81–Y	\$291–Y	Y
Small—Electric controllers—solar	238–Y	856–Y	119–Y	428–Y	Y
Small—Compressed air—grid	1,969–Y	7,082–N	984–Y	3,541–Y	Y
Small—Compressed air—generator	2,673–N	9,615–N	1,336–Y	4,807–Y	Y
Medium—Electric controllers—grid	96–Y	344–Y	48–Y	172–Y	Y
Medium—Electric controllers—solar	167–Y	602–Y	84–Y	301–Y	Y
Medium—Compressed air—grid	1,062–Y	3,820–Y	531–Y	1,910–Y	Y
Medium—Compressed air—generator	1,187–Y	4,270–Y	594–Y	2,135–Y	Y
Large—Electric controllers—grid	62–Y	222–Y	31–Y	111–Y	Y
Large—Electric controllers—solar	130–Y	467–Y	65–Y	234–Y	Y

¹⁴² See Document ID No. EPA-HQ-OAR-2021-0317-0808.

TABLE 25—SUMMARY OF PNEUMATIC CONTROLLER SYSTEMS NOT DRIVEN BY NATURAL GAS COST EFFECTIVENESS FOR NEW SOURCES—Continued

Segment/model plant	Cost effectiveness (\$/ton) ^a —reasonable?				Overall ^a
	Single pollutant		Multipollutant		
	Methane	VOC	Methane	VOC	
Large—Compressed air—grid	593–Y	2,135–Y	297–Y	1,067–Y	Y
Large—Compressed air—generator	780–Y	2,805–Y	390–Y	1,402–Y	Y
Transmission and Storage:					
Small—Electric controllers—grid	247–Y	8,942–N	124–Y	4,471–Y	Y
Small—Electric controllers—solar	364–Y	13,164–N	182–Y	6,582–N	Y
Small—Compressed air—grid	3,015–N	108,939–N	1,507–Y	54,469–N	N
Small—Compressed air—generator	4,093–N	147,891–N	2,046–N	73,946–N	N
Medium—Electric controllers—grid	207–Y	7,474–N	103–Y	3,737–Y	Y
Medium—Electric controllers—solar	362–Y	13,082–N	181–Y	6,541–N	Y
Medium—Compressed air—grid	2,299–N	83,066–N	1,149–Y	41,533–N	N
Medium—Compressed air—generator	2,570–N	92,854–N	1,285–Y	46,427–N	N
Large—Electric controllers—grid	134–Y	4,830–Y	67–Y	2,415–Y	Y
Large—Electric controllers—solar	281–Y	10,156–N	141–Y	5,078–Y	Y
Large—Compressed air—grid	1,285–Y	46,422–N	642–Y	23,211–N	Y
Large—Compressed air—generator	1,688–Y	60,992–N	844–Y	30,496–N	Y

^aFor the production and processing segments, the owners and operators realize the savings for the natural gas that not emitted and lost. The cost effectiveness values shown do not consider these savings. Note that the consideration of savings does not impact whether the cost effectiveness of any of these options falls within the ranges considered reasonable by the EPA.

^bFor overall cost effectiveness to be considered reasonable, either the cost effectiveness of methane or VOC on a single pollutant basis must be within the ranges considered reasonable by the EPA, or the cost effectiveness of both methane and VOC on a multipollutant basis must be within the ranges considered reasonable by the EPA.

iii. Proposed BSER Conclusion.

As demonstrated in the analysis and shown in Table 25, there are pneumatic controller options for controllers not driven by natural gas at sites in the production and transmission and storage segments where the cost effectiveness is within the ranges considered to be reasonable by the EPA. These options can be utilized at sites with access to grid electricity and remote sites that do not have this access. This conclusion is consistent with the findings in the November 2021 proposal.

In addition to these options that use pneumatic controllers not driven by natural gas, there are two types of natural gas-driven controllers that we are proposing as zero-emissions options: (1) Controllers whose emissions are collected and routed to a process, and (2) self-contained natural gas pneumatic controllers. As noted in section IV.D.1.b.i, these natural-gas driven controllers are included in the revised proposed definition of affected facility, meaning that they would be subject to standards to ensure that they are operated and maintained in a manner that ensures zero emissions of methane and VOC. We are including these as compliance options in this proposed action because: (1) they are included as compliance options under several state rules, and (2) there is cursory information indicating that they are utilized in some locations. However, the available information about the

prevalence of either of these options at sites in the oil and natural gas production or transmission and storage segments is very limited. Therefore, the EPA is requesting is requesting comment on several issues related to these controllers.

The EPA is interested in several aspects related to the option of collecting the pneumatic controller emissions and routing them to a process. First, we are soliciting information that describes specific situations where owners and operators have utilized this option to use, rather than lose, the valuable natural gas emitted from pneumatic controllers. We are interested in the specific processes and equipment needed, as well as their costs.

Second, our understanding is that routing emissions from pneumatic controllers to a process achieves a 100 percent reduction in emissions. This understanding is based on the fact that the natural gas that is emitted from pneumatic controllers is drawn directly from the raw product gas stream that will be collected and routed to a gathering and boosting station and eventually to a natural gas processing plant (*i.e.*, the gas “sales line”). Therefore, the emissions from pneumatic controllers are of the same composition as the gas in the sales line. Since the emissions are at atmospheric pressure, it is likely that the gas would need to be compressed prior to re-introduction to the sales line. We do not

expect that this compression would result in emissions. Similarly, since the gas composition of these emissions is typically high in methane, the heat content would make it amendable to being used as fuel, or introduced with the primary fuel stream for use in an engine without the need for additional processing that could result in emissions. We are interested in information to support this understanding that routing emissions from pneumatic controllers to a process achieves a 100 percent reduction in emissions.

The 100 percent emissions reductions that we believe can be achieved for controllers contrasts with routing emissions from storage vessels or centrifugal compressor wet seal fluid degassing systems to a process where the emissions are of a different composition from the sales gas. For these situations, a VRU or other treatment is necessary to obtain a gas stream whose composition is suitable to be returned to the sales line or used for another purpose. A VRU often includes a scrubber, separator, condenser, or other component that has a small vent stream emitted to the atmosphere. In addition, the complex nature of VRUs results in the need for maintenance or other situations where the VRU may be bypassed, and emissions vented for short periods of time. Because of both of these situations, the EPA has historically assumed that VRUs achieve

a 95 percent reduction or greater in emissions.

The EPA requests information on the assumption that installation of VRUs would not be needed to enable the use of emissions from pneumatic controllers in a process. If there are situations where a VRU is needed, the EPA is interested in the conditions that result in this need, as well as the emissions reduction achieved and the costs.

We are aware of technical limitations of self-contained controllers, namely that their applicability is limited by a number of conditions (e.g., pressure differential, downstream pressure, etc.). The EPA is therefore specifically soliciting information on the frequency of the use of these self-contained controllers in the field, as well as confirmation of specific limitations and costs. We are also interested in information to support our understanding that self-contained controllers achieve 100 percent reduction in emissions when maintained and operated properly.

Several commenters maintain that there are technical limitations that will not allow pneumatic controllers not driven by natural gas to be utilized at sites without electricity, particularly solar-powered controllers.¹⁴³ One commenter stated that while the EPA suggested the use of onsite solar generation paired with battery storage as an alternative to grid electricity, such systems are currently “uncommon, unreliable, and will likely increase the frequency of facility upsets, which will increase safety risks such as overpressure events and spills.”¹⁴⁴ Another commenter stated that while there may be some pilot projects within the industry, it has not been demonstrated that reliable turnkey packages are available on a widescale basis.¹⁴⁵ Several commenters noted that there are severe geographic limitations to the use of any solar-powered devices. One noted that West Virginia averages only 164 days of sunshine per year, compared with an average of 205 days for the rest of the United States. Even in typically sunny states, operations in canyons or mountain valleys receive significantly limited sunlight exposure. Snow and ice raise additional reliability concerns during winter months.¹⁴⁶

Another commenter stated that large-scale solar applications have not yet been tested in winter months when there is more cloud coverage, increased snow cover, and less sunlight in more northern locations (e.g., Colorado, North Dakota, Idaho, and Wyoming).¹⁴⁷ One industry organization agreed that solar power might be an option but reported that their member companies have not yet been able to demonstrate this to be universally true in Utah’s Uinta Basin. This organization cited specific problems such as the requirement of excess generation and battery storage capacity to maintain operations during wintertime inversions and challenges from snowstorms, which could cover the solar panels and inhibit or prevent electricity generation. They conclude that utilizing solar electricity for oil and gas operations in Utah may be labor intensive, costly, and unreliable such that operations would still require backup power from the electric grid or from generators.¹⁴⁸ Another commenter also mentioned that it is probable that supplemental power via natural gas or diesel-powered generators could be required during winter months and/or severe weather events, which would be necessary to ensure a continuous power supply, and, thus, a controlled operation. This commenter also noted that interruptions within the control system pose safety risks to operators and can damage processing equipment, which could potentially lead to excess emissions associated with equipment malfunctions.¹⁴⁹

One commenter indicated that they were unaware of any operators converting to solar-powered electric controllers at this time. They said while the technology seems promising, many of these solar systems have not yet been proven reliable for all remote locations or facility designs and are not ready for deployment across the country at the large scale that the EPA’s proposed rules would require. They note that in 2014, the EPA stated “solar-powered controllers can replace continuous bleed controllers in certain applications but are not broadly applicable to all segments of the oil and natural gas industry.”¹⁵⁰

However, other commenters disagreed and supported the EPA’s November

2021 proposal to require zero-emission controllers. Commenters cited several state rules that require all new pneumatic controllers to be non-emitting, including states with colder climates (Colorado). As the EPA also indicated in the November 2021 proposal, there are Canadian provinces that have successfully implemented non-emitting controller regulations. Comments were also provided by vendors that report the successful installation and operation of zero-emission controller systems in a variety of climate conditions.¹⁵¹ One of these vendors notes the installation of solar-driven instrument air systems in several states, including Wyoming and Colorado.¹⁵²

In a supplement to their 2022 report that was provided in a late comment, Carbon Limits addressed many of the alleged shortcomings of solar and other zero-emitting controller technologies raised in public comments. They state, “[a]ddressing the queries on the reliability of solar systems for remote locations and cold states, the technology providers and operators interviewed as part of this assessment have solar-powered controllers installed at well sites in remote and cold locations such as Northern Alberta and British Columbia, without major reliability issues. Some of the interviewed technology providers have installed these systems in over 400 well-sites in these states and provinces. The commenter further refers to a statement by the EPA from 2014. However, it is to be noted that solar technology has improved drastically from 2014 to 2021. Efficiency has increased while costs have gone down significantly. Solar-powered controllers are capable of operating at low temperatures and remote locations, among different gas sectors. When it comes to snow cover on panels affecting the performance of solar cells, all the interviewees stated that the panels are placed at a low angle, to catch ample sun in the winter months. Most often, these panels are placed vertically, eliminating snow cover on the solar panels.”¹⁵³ Commenters also indicated that at sites without electricity, owners or operators could install a generator to power an instrument air system.

Under CAA section 111(b), EPA must show that a BSER determination has been “adequately demonstrated.” The EPA concludes that zero-emission

¹⁴³ See Document ID Nos. EPA–HQ–OAR–2021–0317–0817, EPA–HQ–OAR–2021–0317–0743, EPA–HQ–OAR–2021–0317–0749, and EPA–HQ–OAR–2021–0317–0808.

¹⁴⁴ See Document ID No. EPA–HQ–OAR–2021–0317–0793.

¹⁴⁵ See Document ID No. EPA–HQ–OAR–2021–0317–0599.

¹⁴⁶ See Document ID No. EPA–HQ–OAR–2021–0317–0817.

¹⁴⁷ See Document ID No. EPA–HQ–OAR–2021–0317–0808.

¹⁴⁸ See Document ID No. EPA–HQ–OAR–2021–0317–0740.

¹⁴⁹ See Document ID No. EPA–HQ–OAR–2021–0317–0808.

¹⁵⁰ Oil and Natural Gas Sector Pneumatic Devices, Review Panel, USEPA, OAQPS, 2014: <https://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-devices.pdf>.

¹⁵¹ See Document ID Nos. EPA–HQ–OAR–2021–0317–0838 and EPA–HQ–OAR–2021–0317–0802.

¹⁵² See Document ID No. EPA–HQ–OAR–2021–0317–0838.

¹⁵³ See Document ID No. EPA–HQ–OAR–2021–0317–1451.

pneumatic controller systems that do not use natural gas meet this standard at sites both with and without access to electricity. In addition, as discussed above, we have concluded that there are options available at sites in all segments of the industry that have cost-effective values considered reasonable by the EPA.

Secondary impacts from these non-natural gas-driven, zero-emission controllers, particularly from the use of instrument air systems are indirect, variable, and dependent on the electrical supply used to power the compressor. The 2016 Carbon Limits report indicates that a small instrument air compressor would require around 5 horsepower (HP) of air compression capacity, while a larger facility would require up to 20 HP. Assuming the compressor operates one-half of the total hours in a year, and using an electricity factor of 0.75 HP/kilowatt, the compressor yields an annual electricity usage of around 100 mmBtu/yr for a 5 HP compressor and 400 mmBtu/yr for a 20 HP compressor. There would be secondary air pollution impacts associated with the generation of this electricity. The secondary criteria pollutant emissions are estimated to be 7 lbs/yr CO, 60 lbs/yr NO₂, 3 lbs/yr PM, 1 lb/yr PM_{2.5}, and 120 lbs/yr SO₂ for a 5 HP compressor and 29 lbs/yr CO, 239 lbs/yr NO₂, 12 lbs/yr PM, 4 lb/yr PM_{2.5}, and 478 lbs/yr SO₂ for a 20 HP compressor. The secondary GHG emissions generated as a result of this electricity generation are 20,489 lbs/yr CO₂, 2 lbs/yr methane, and 1lb/yr N₂O for a 5 HP compressor and 81,955 lbs/yr CO₂, 10 lbs/yr methane, and 2 lbs/yr N₂O for a 20 HP compressor. Considering the global warming potential of these GHGs, the total CO₂e emissions would be 20,667 lbs CO₂e from a 5 HP compressor and 82,669 lbs CO₂e from a 20 HP compressor. These total CO₂e would represent a more than 90 percent reduction in the CO₂e emissions when compared to the uncontrolled methane emissions from natural gas driven controllers. No other secondary impacts are expected.

Commenters indicated that at sites without electricity, owners or operators would likely install a generator to power an instrument air system. These commenters contended that relying on a generator would result in emissions of criteria pollutants and carbon monoxide (CO) that could potentially offset the emissions reductions from the methane and VOC. One commenter provided an estimate that a natural gas-fired generator of approximately 200 horsepower would be needed to support reliable operation of a large instrument

air system without grid power. This commenter estimated emissions from a generator that size to be 1.94 tpy NO_x, 3.88 tpy of CO, 1.36 tpy of VOC, 0.12 tpy of particulate matter with a diameter of 10 micrometers or less (PM₁₀), 0.14 tpy CH₄ and 730 tpy of CO₂.¹⁵⁴

The EPA recognizes that if owners and operators elect to comply by installing and operating a generator, there will be secondary emissions generated from the fuel combustion. However, we also point out that, for a site with 100 controllers (a size cited by the commenter requiring a large instrument air system), these secondary emissions would represent approximately a 77 percent decrease in CO₂ equivalent emissions and a 96 percent decrease in VOC emissions from a site with 25 low bleed and 75 intermittent bleed controllers.

In light of the above, we find that the BSER for reducing methane and VOC emissions from natural gas-driven controllers in the production and transmission and storage segments of the industry to be the use of controllers that have a methane and VOC emission rate of zero. This option results in a 100 percent reduction of emissions for both methane and VOC. Therefore, for NSPS OOOOb, we are proposing to require that each pneumatic controller affected facility be designed and operated with a methane and VOC emission rate of zero in the production and transmission and storage segments of the source category, with the following exception for sites in Alaska that do not have access to grid electricity.

In the November 2021 proposal, we determined a separate BSER for the subset of pneumatic controllers, specifically those at sites in Alaska that do not have access to electricity. We also proposed specific requirements for these controllers. We are not proposing any changes to these requirements in this supplemental proposal. Specifically, these sites would be required to use low-bleed controllers (instead of high-bleed controllers) and would be allowed to use high-bleed controllers instead of low-bleed based only upon a showing of functional needs. In addition, we proposed that owners or operators at such sites be required to inspect intermittent vent controllers to ensure they are not venting during idle periods. The rationale for this decision was discussed in the November 2021 proposal (86 FR 63207; November 15, 2021).

The EPA notes that the BSER determination for pneumatic controllers

at natural gas processing plants was also not revisited in this supplemental proposal. Therefore, the November 2021 BSER determination of zero emission controllers at natural gas processing plants is retained in this supplemental proposal. The rationale for this decision is contained in the November 2021 proposal (86 FR 63207- 63208; November 15, 2021).

iv. Routing to an Existing Control Device

Several commenters requested that the EPA include an option to collect the emissions from natural gas-driven controllers and route them to a flare or combustion device that achieves 95 percent reduction in methane and VOC. These comments stated that in many situations, an onsite control device already exists and that using it would be a cost-effective method of achieving significant emission reductions.

The EPA acknowledges that this is a viable option to achieve emission reductions from natural gas-driven pneumatic controllers. However, as discussed above, we have determined that BSER for pneumatic controllers is use of one of the several types of controllers that have zero methane and VOC emissions. Thus, routing to an existing control device (*i.e.*, achieving 95 percent reduction) would result in a less stringent standard than the BSER. In the 2021 Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHGI), the estimated methane emissions for 2019 from pneumatic controllers were 700,000 metric tons of methane for petroleum systems and 1.4 million metric tons for natural gas systems. These levels represent 45 percent of the total methane emissions estimated from all petroleum systems (*i.e.*, exploration through refining) sources and 22 percent of all methane emissions from natural gas systems (*i.e.*, exploration through distribution). While we recognize that these emissions include emissions from existing sources, it is clear that pneumatic controllers represent a significant source of methane and VOC emissions. Allowing an option that results in 5 percent more emissions would be a quite significant increase.

The EPA recognizes that there are other instances in the proposed rule where there are options allowed that are less stringent than the measures determined to be BSER. However, in each of these situations, the EPA is convinced that there are genuine technical limitations or safety issues that make compliance with the BSER infeasible. For pneumatic controllers, the EPA maintains that there is a

¹⁵⁴ See Document ID No. EPA-HQ-OAR-2021-0317-0808.

technically feasible option available for all production, processing, and transmission and storage sites, except for sites in Alaska without access to electricity. Therefore, the proposed NSPS OOOOb does not include any alternative non-zero emission standards for pneumatic controllers. The EPA is interested in information that may dispute the conclusion that there is a technically feasible option that does not emit methane or VOC available for all sites in all segments. Some commenters raised concerns about specific situations that may make individual technologies impracticable to implement (e.g., the inability of solar-powered controller systems to meet the needs at certain remote locations that do not have access to electricity). Although the EPA will consider any additional information commenters may submit about such situations, the EPA notes that there are multiple options for meeting the proposed zero-emission standard and that limitations on the use of one technology at any given site does not mean that other options for meeting the standard are unavailable. As a result, the EPA is particularly interested in understanding whether there are site characteristics that would make every zero-emitting option (electric controllers powered by the grid or by solar power; instrument air systems powered by the grid, a generator, or by solar power; collecting the emissions and routing them to a process; self-contained controllers, *etc.*) technically infeasible at the site.

c. Summary of Proposed Standards

In this supplemental proposal, the pneumatic controller affected facility is defined as the collection of natural gas-driven pneumatic controllers at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station. This definition applies in all segments of the oil and natural gas source category. Natural gas-driven pneumatic controllers that function as emergency shutdown devices and pneumatic controllers that are not driven by natural gas are exempt from the affected facility, provided that the records are maintained to document these conditions. In addition to the modification definition in 40 CFR 60.14 and the reconstruction definition in 40 CFR 60.15, the proposed rule includes clarification of these terms for the pneumatic controller affected facility. A modification occurs when the number of natural gas-driven pneumatic controllers at a site is increased by one or more, and reconstruction occurs when either the cost of the controllers being replaced exceeds 50 percent of the

cost to replace all the controllers, or when 50 percent or more of the pneumatic controllers at a site are replaced.

The proposed standard for pneumatic controller affected facilities is zero emissions of methane and VOC to the atmosphere. An exception to this standard exists for pneumatic controller affected facilities located at sites in Alaska without access to electrical power. The proposed rule does not specify how this emission rate of zero must be achieved, but a variety of viable options are available. All controllers at a site that are not driven by natural gas (e.g., pneumatic controllers driven by compressed air, electric controllers, solar-powered controllers) are not part of the pneumatic controller affected facility, provided that documentation is maintained as previously discussed. If all pneumatic controllers at a site are not natural gas-driven, then there would be no pneumatic controller affected facility at the site, provided the documentation is maintained.

Natural gas-driven controllers can comply with the zero emissions standard by collecting and routing emissions via a CVS to process, or by using self-contained controllers. The proposed rule defines a self-contained pneumatic controller as a natural gas-driven pneumatic controller that releases gas into the downstream piping and not to the atmosphere, resulting in zero methane and VOC emissions.

If you comply by routing the emissions to a process, the CVS that collects the emissions must be routed to a process through a CVS that meets the requirements in proposed 40 CFR 60.5411b, paragraphs (a) and (c). These requirements include certification by a professional or in-house engineer that the CVS was designed properly, and that the CVS is operated with no identifiable emissions as demonstrated through initial and periodic inspections, observations, and measurements. This includes monitoring using OGI at the same frequency as required under the fugitive monitoring program. All issues identified must be corrected. Required records would include the certification and records of all inspections and any corrective actions to repair the defect or the leak.

If you comply by using a self-contained natural gas-driven pneumatic controller, the controller must be designed and operated with no detectable emissions, as demonstrated by conducting initial and quarterly inspections using optical gas imaging. Required records would include records of all inspections and any corrective actions to repair the defect or the leak.

The proposed rule includes an exemption from the zero-emission requirement for pneumatic controllers in Alaska at locations where electrical power is not available. In these situations, the proposed standards require the use of a low-bleed controller (*i.e.*, a controller with a natural gas bleed rate less than or equal to 6 scfh). Records would be required to demonstrate that the controller is designed and operated to achieve a bleed rate less than or equal to 6 scfh. For controllers in Alaska at location without electrical power, the proposed rule includes the exemption that would allow the use of high-bleed controllers instead of low-bleed based on functional needs (including but not limited to response time, safety, or positive actuation). To utilize this exemption, a demonstration of the functional need must be made and submitted in the initial annual report. The proposed rule also includes requirements for natural gas-driven intermittent vent controllers at these sites in Alaska without access to electrical power. Specifically, the proposed rule would require that an intermittent vent not vent to the atmosphere during idle periods. Compliance with this requirement would be demonstrated by modifying the fugitive emissions monitoring plan to include these intermittent vents, monitoring them at the schedule required by the site for the fugitive emissions components affected facility, and repairing any leaks or defects identified. Records would be required of all inspections and repairs.

2. EG OOOOc

The November 2021 proposal defined the pneumatic controller designated facility for EG OOOOc as each natural gas-driven controller. As with the change discussed above for the NSPS OOOOb affected facility, we are also proposing that the EG OOOOc designated facility definition to be the collection of natural gas-driven pneumatic controllers at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station. This definition applies in all segments of the oil and natural gas source category.

In response to comments received and additional information collected, we also updated the BSER analysis for existing sources. The same basic changes were made to the existing source analysis as discussed above for the new source analysis. However, there were a few instances where the emissions and costs differed for existing sources as compared to new. These are discussed in the following sections.

a. Model Plant Emissions

As noted above, for the new source analysis we adjusted the model facilities to remove all high-bleed controllers since NSPS OOOOa and many state

rules already prohibit the use of high-bleed controllers. While there are limited instances where states impose this requirement on existing sources, we concluded that the best representation for pneumatic controller model plants

was to include one high-bleed for each type of facility. The emissions, calculated using the updated emission factors provided in Table 22, are provided below in Table 26.

TABLE 26—SUMMARY FOR PNEUMATIC CONTROLLER MODEL PLANTS FOR EXISTING SOURCES

Segment/model plant	Number of controllers			Methane emissions (tpy)
	High bleed	Low bleed	Intermittent vent	
Production:				
Small	1	1	2	6.9
Medium	1	1	6	12.2
High	1	4	15	27.3
Transmission and Storage:				
Small	1	1	2	7.4
Medium	1	1	6	9.0
High	1	4	15	15.9

b. Costs for Controllers Not Driven by Natural Gas

There were instances where the estimated costs for the systems for controllers not driven by natural gas were different for existing sources and for new sources. Following are brief descriptions of the reasons for these differences.

For electric and solar-powered controllers, the new source capital costs included the cost for controller valves. For existing sources, we assumed that the existing valves could be used for converting from natural gas pneumatic controllers. For new sites, the cost of natural gas-driven controllers was subtracted from the cost of the

controllers not driven by natural gas, as those capital expenses would be “saved.” This adjustment was not made for existing sources. We assumed that the relative engineering and installation costs would be higher at an existing site; therefore, we assume an engineering and installation cost of 100 percent of the capital costs. For instrument air systems, the new site costs included costs for the new controllers, while the assumption was that existing sources could continue to use the existing controllers that were formerly driven by natural gas. The instrumentation cost for a retrofit for an existing site was assumed to be 40 percent higher than for a new site, and the engineering and installation costs were assumed to be

100 percent of the capital costs for existing sites (as opposed to 50 percent for new sites). As with electric and solar-powered controllers, the cost of the natural gas-driven controllers not needed was not subtracted from the existing source capital costs.

The operation and maintenance costs for existing sources used were the same as for new sources. Therefore, the only difference in total annual costs was due to the difference in the capital recovery costs because of the different total capital investment.

Table 27 compares the total capital investment and total annual cost for new sources and existing sources for each model plant and zero emission controller technology.

TABLE 27—COMPARISON OF TOTAL CAPITAL AND ANNUAL COSTS FOR NON-EMITTING CONTROLLERS NOT DRIVEN BY NATURAL GAS AT NEW AND EXISTING SOURCES

Model plant	New sources		Existing sources	
	Adjusted TCI ^{a b}	TAC ^c	TCI ^a	TAC ^{c d}
Electric:				
Small System	\$15,287	\$762	\$20,593	\$1,345
Medium System	25,426	1,112	34,322	1,936
Large System	55,842	1,550	75,508	3,709
Solar:				
Small System	16,831	959	22,653	1,761
Medium System	28,515	1,679	38,441	2,768
Large System	63,049	3,258	85,119	5,681
Instrument Air System—Grid:				
Small System	47,512	9,285	58,636	10,506
Medium System	71,426	10,658	76,481	11,213
Large System	113,277	14,891	127,469	16,449
Instrument Air System—Generator:				
Small System	95,115	12,604	120,000	15,337
Medium System	100,231	11,914	120,000	14,085
Large System	190,577	19,565	220,000	22,795

^a TCI = Total capital investment includes capital cost of equipment plus engineering and installation costs.

^b Adjusted TCI = Total capital investment minus the cost that would have been incurred if natural gas-driven controllers had been installed.

^c TAC = Total annual costs including capital recovery (at 7 percent interest and 15-year equipment life) and operation and maintenance costs.

^d For the production segment, the owners and operators realize the savings for the natural gas that not emitted and lost. The cost values shown do not consider these savings.

- c. Existing Source BSER Determination
Table 28 shows the cost effectiveness values for methane of the controller technologies that are not driven by natural gas and that do not emit methane.

TABLE 28—SUMMARY OF PNEUMATIC CONTROLLER SYSTEMS NOT DRIVEN BY NATURAL GAS METHANE COST EFFECTIVENESS FOR EXISTING SOURCES

Segment—model plant	Cost effectiveness ^a (\$/ton methane reduced)	Reasonable?
Production Segment:		
Small—Electric controllers—grid	\$195	Y
Small—Electric controllers—solar	255	Y
Small—Compressed air—grid	1,524	Y
Small—Compressed air—generator	2,225	N
Medium—Electric controllers—grid	158	Y
Medium—Electric controllers—solar	227	Y
Medium—Compressed air—grid	918	Y
Medium—Compressed air—generator	1,153	Y
Large—Electric controllers—grid	136	Y
Large—Electric controllers—solar	208	Y
Large—Compressed air—grid	603	Y
Large—Compressed air—generator	836	Y
Transmission and Storage Segment:		
Small—Electric controllers—grid	181	Y
Small—Electric controllers—solar	238	Y
Small—Compressed air—grid	1,418	Y
Small—Compressed air—generator	2,069	Y
Medium—Electric controllers—grid	216	Y
Medium—Electric controllers—solar	309	Y
Medium—Compressed air—grid	1,250	Y
Medium—Compressed air—generator	1,571	Y
Large—Electric controllers—grid	233	Y
Large—Electric controllers—solar	357	Y
Large—Compressed air—grid	1,033	Y
Large—Compressed air—generator	1,432	Y

^aFor the production segment, the owners and operators realize the savings for the natural gas that not emitted and lost. The cost effectiveness values shown do not consider these savings. Note that the consideration of savings does not impact whether the cost effectiveness of any of these options falls within the ranges considered reasonable by the EPA.

As shown in Table 28, all options evaluated, with the exception of an instrument air system driven by a generator at a small model plant, have cost effectiveness values within the range that the EPA considers reasonable for methane.

Further, as discussed at length above in section IV.D.1.b.iii, the EPA finds that these controller technologies not driven by natural gas are technically feasible in locations with and without electrical power. Owners and operators can use natural gas-driven low or high bleed controllers or intermittent controllers, provided the emissions are collected and routed through a CVS to a process. Finally, owners and operators have the option of using natural gas-driven self-contained controllers.

Secondary impacts from these options, particularly from the use of instrument air systems, are indirect, variable, and dependent on the electrical supply used to power the compressor. As discussed above, this would result in an increase in electricity needs and minimal emission increases.

As discussed above, the use of a generator to power an instrument air system will result in emissions of two criteria pollutants—CO and CO₂. However, the comparison in the CO₂ equivalent emissions shows that even with the secondary emissions from the generator, there is a substantial reduction in CO₂ equivalent emissions.

In light of the above, we find that the BSER for reducing methane emissions from existing natural gas-driven controllers in the production and transmission and storage segments of the industry to be the use of controllers that have a methane emission rate of zero. This option results in a 100 percent reduction of emissions of methane. Therefore, for EG OOOOc, we are proposing to require that each pneumatic controller affected facility be designed and operated with a methane emission rate of zero for all pneumatic controllers in the production and transmission and storage segments of the source category, with the exception discussed below.

As discussed above for new sources, we did not re-evaluate BSER for sites in Alaska that do not have access to electricity and are proposing the same requirements as in the November 2021 proposal. Similarly, we did not re-evaluate BSER for pneumatic controllers at existing natural gas processing plants. Therefore, the November 2021 BSER determination of zero-emission controllers at natural gas processing plants is retained in this supplemental proposal.

The proposed standards and other requirements for existing pneumatic controller designated facilities under EG OOOOc are the same as described above for new pneumatic controller affected facilities under the NSPS OOOOb.

d. Additional Comments

There were two additional topics raised in the public comments that are discussed in this section: (1) The potential exemption of small sites with low production and/or a low number of controllers, and (2) issues associated with the supply chain.

i. Small Site Exemptions.

Several commenters requested that the EPA include an exemption for small sites with low production and/or a low number of pneumatic controllers. The commenters provided a range of pneumatic controllers that they felt represented a reasonable cut-off, ranging from 3 to 30 controllers.

The EPA notes that the cost effectiveness values for the smallest model plant, which includes 1 high-bleed, 1 low-bleed, and 2 intermittent vent controllers, were \$181 and \$238 per ton of methane reduced for electric controllers and solar controllers, respectively. These cost effectiveness values are well within the ranges considered to be reasonable by the EPA. We also performed an analysis of the cost effectiveness of the use of electric controllers and solar-powered controllers at sites with a single controller. For sites with only one high-bleed controller, the cost effectiveness was estimated to be \$379 and \$437 per ton of methane reduced for electric and solar-powered controllers, respectively. For a site with one intermittent vent controller, the cost effectiveness values were estimated as \$913 per ton for electric controllers, and \$1,053 per ton for solar-powered controllers. For a site with one low-bleed controller, the cost effectiveness values were \$1,181 per ton for electric controllers and \$1,363 per ton for solar-powered controllers. As all of these cost effectiveness values are within the range considered reasonable for methane by the EPA, this analysis does not support an exemption for sites with low numbers of pneumatic controllers.

One commenter stated that even at the current prices for natural gas, it would take the average low-production natural gas well about six years of all of its profits to pay for the electric grid option and more than that for the solar option. The commenter added that for a Pennsylvania well site, the time period would be 70 or more years.¹⁵⁵ This commenter did not provide details of their analysis. While the EPA recognizes that that impacts on profitability are generally not considered in determining BSER, we are interested in the details of the analysis of profit margins at low production wells. Specific to this information provided by the commenter, dividing the total estimated capital investment of an electric controller system for the small model plant (\$20,593) by six years results in \$3,400 per year. If it is assumed that this capital investment is financed for six

years at a 7 percent interest rate, this cost would be around \$4,300 per year, which equates to around \$360 per month. The EPA is interested in learning whether this amount represents typical profit margins for low production wells.

Another commenter added that the cost of converting to an electronic controller or instrument air system will likely result in the shut-in of many small, low-production well sites. These sites have a remaining useful life that will be cut short by the proposed rule's pneumatic controller requirements.¹⁵⁶

The EPA notes that the implementing regulations for emission guidelines contained in 40 CFR part 60, subpart Ba include provisions that allow states to develop a less stringent standard taking into consideration factors such as the remaining useful life of such source. For more information on remaining useful life and other factors considerations, see section V.C of this preamble.

ii. Supply Chain Issues

In light of the proposal to require zero-emission pneumatic controllers for both new and existing sources, the EPA would like to address several comments it received and solicit related information. One commenter predicted that the requirements will likely generate supply chain shortages and the small operators will be last to procure the necessary equipment at the highest price.¹⁵⁷ Another commenter stated that the EPA has not adequately considered the impacts of the current supply chain interruptions on the ability of operators to comply with the rule. Specialized equipment, such as air compressors, electric controllers, and equipment needed to retrofit facilities have been particularly hard-hit by supply chain constraints related to COVID-19. This commenter reported that owners and operators have already experienced delays of several months in acquiring equipment to retrofit facilities to instrument air, all prior to the EPA proposal, and that the increased demand for that equipment given proposed rule requirements would only exacerbate the challenges associated with acquiring that equipment.¹⁵⁸ For existing sources, the EPA points out that several years will pass between the time EG OOOOc is finalized and the compliance dates for state rules, thus allowing a substantial amount of time for adjustments in the supply chain.

While the commenters primarily focused on potential supply chain issues related to requiring the conversion to zero emissions controllers at existing sources, the EPA also understands that the promulgation of NSPS OOOOb could also result in a spike in the demand. In light of these comments, the EPA is specifically requesting additional comment on the availability of zero-emission pneumatic controller systems not powered by natural gas due to supply chain constraints or other reasons.

E. Pneumatic Pumps

A pneumatic pump is a positive displacement reciprocating unit generally used by the Oil and Natural Gas Industry for one of four purposes: (1) Hot oil circulation for heat tracing/freeze protection, (2) chemical injection, (3) moving bulk liquids, and (4) glycol circulation in dehydrators. There are two basic types of pneumatic pumps used in the Oil and Natural Gas Industry—diaphragm pumps and piston pumps. Natural gas-driven pneumatic pumps emit methane and VOCs as part of their normal operation. Detailed information on pneumatic pumps, including their functions, operations, and emissions, is provided in the preamble for the November 2021 proposal (86 FR 63224–63226; November 15, 2021).

1. NSPS OOOOb

a. November 2021 Proposal

In the November 2021 proposal, a pneumatic pump affected facility was defined as each natural gas-driven diaphragm or piston pump in any segment of the source category. The proposed definition of an affected facility excluded lean glycol circulation pumps that rely on energy exchange with the rich glycol from the contractor.

For pneumatic pumps in the production and transmission and storage segments, the November 2021 proposal would have required that the emissions be routed to an existing control device that achieves 95 percent control of methane and VOCs, or to route the emissions to an existing VRU and to a process. This proposed standard would have covered both diaphragm and piston pumps. The proposed rule did not propose to require that a new control device be installed. At natural gas processing plants, the proposed rule would have required the prohibition of methane and VOC emissions from pneumatic pumps.

The BSER analysis that led to the November 2021 proposed pneumatic pump requirements for the production

¹⁵⁶ See Document ID No. EPA-HQ-OAR-2021-0317-0777.

¹⁵⁷ See Document ID No. EPA-HQ-OAR-2021-0317-0814.

¹⁵⁸ See Document ID No. EPA-HQ-OAR-2021-0317-0743.

¹⁵⁵ See Document ID No. EPA-HQ-OAR-2021-0317-0814.

and transmission segments concluded that the cost effectiveness for routing to an existing control device was reasonable. The EPA also concluded that it was not cost-effective to require the owner or operator of a pneumatic pump to install a new control device or process onsite to capture emissions solely for this purpose.

The EPA also evaluated pneumatic pumps that are not powered by natural gas. Specifically, the types of pumps evaluated were electric pumps, solar-powered pumps, and pumps powered by compressed air. We found that the cost-effectiveness of these options, for both diaphragm and piston pumps, were generally within the ranges that the EPA considers reasonable. However, for instrument air systems and electric pumps, our analysis assumed that electrical power was available onsite. We noted that commenters have raised concerns in the past regarding solar-powered pneumatic pumps, which have technical limitations that do not make them universally feasible for locations without access to electrical power. In November 2021, we did not have information that such limitations had been overcome, and we were therefore unable to conclude that pumps not driven by natural gas represented BSER at that time. We solicited comment on this issue to better understand whether options that do not use natural gas are technically feasible at sites without electrical power. We also solicited comment on an approach that would subcategorize pneumatic pumps located at production and transmission and storage sites based on availability of electricity and would then set separate standards for each subcategory.

Since all natural gas processing plants have access to electrical power, we only evaluated compressed air systems for this segment. The cost effectiveness of these systems was found to be in the range considered to be reasonable by the EPA, and we therefore concluded that BSER was pneumatic pumps that are not driven by natural gas.

b. Changes to Proposal and Rationale

The proposed NSPS OOOOb requirements in this supplemental proposal differ from the November 2021 proposal in several ways, starting with the affected facility definition. As noted above, in the November 2021 proposal, a pneumatic pump affected facility was defined as each natural gas-driven pneumatic pump. In this supplemental proposal, a pneumatic pump affected facility is defined as the collection of all natural gas-driven pneumatic pumps at a site.

After considering comments on the emissions standards, as well as the information submitted in response to our specific solicitations for information, the EPA is now proposing a zero-emissions standard for pneumatic pump affected facilities in all segments of the industry. Specifically, the EPA is proposing that pneumatic pumps not driven by natural gas be used. This is a significant change from the November 2021 proposal, which would have required that emissions from pneumatic pump affected facilities be routed to control or to a process, but only if an existing control or process was on site.

The proposed rule recognizes that at sites without access to electricity, there could be situations where it is technically infeasible to use a pump that is not driven by natural gas. As a result, the EPA is proposing to include a tiered structure in the rule that would allow flexibility based on site-specific conditions. At sites without access to electricity, if a demonstration is made that it is technically infeasible to use a pneumatic pump that is not driven by natural gas, the rule would allow the use of a natural gas-driven pump, provided that the emissions are captured and routed to a process, which EPA understands to achieve 100 percent reduction of methane and VOC. Such an infeasibility determination is not allowed if the site has access to electricity. This means the proposed rule would prohibit the use of natural gas-driven pumps at sites with access to electricity.

At sites without access to electricity for which the owner or operator has demonstrated that it is technically infeasible to utilize a pneumatic pump not driven by natural gas, an owner or operator may also demonstrate that it is technically infeasible to capture the pneumatic pump's emissions and route them to a process. Where routing to a process is infeasible, the resulting requirement for emissions control depends on the number of natural gas-driven diaphragm pumps at the site. If there are four or more natural gas-driven pumps at the site, the proposed rule would require that the emissions from all pumps at the site be collected and be routed to a control device that achieves 95 percent reduction of methane and VOC. If there are less than four natural gas-driven diaphragm pumps at the site without access to electricity, the proposed requirements for pumps at the site would be the same as in the November 2021 proposal, *i.e.*, route to an existing control device that achieves 95 percent emissions reductions.

Details on the proposed pneumatic pump requirements are provided in

section IV.D.1.c. The following sections provide the rationale for the significant changes discussed in this section.

i. Changes to Affected Facility, Modification, and Reconstruction

As previously noted, the pneumatic pump affected facility definition changed from being a single pump in the November 2021 proposal to the collection of pumps at a site in this supplemental proposal. In this supplemental proposal, a pneumatic pump affected facility is defined as the collection of all natural gas-driven pneumatic pumps at a site. As we advanced our evaluation of the control measures to reduce methane and VOC emissions from pneumatic pumps, it became apparent that most of the measures to reduce or eliminate emissions are site-wide solutions. For instance, a compressed air system installed at a site would be used to power all pneumatic pumps at the site, not just one, which would alleviate the need for a separate system for each pump. In fact, the cost analysis for the November 2021 proposed rule for compressed air systems was conducted on a "model plant" site-wide basis. Similarly, emissions from all pumps at a site would be routed to a single control device and would therefore not require the installation of a control device for each pump. We are specifically soliciting comment on this proposed change to the definition of a pneumatic pump affected facility from an individual pump to the collection of all natural gas-driven pneumatic pumps at a site.

In addition, some of the means of powering a pneumatic pump without the use of natural gas can also be used to power pneumatic controllers. While our updated BSER analyses for pneumatic pumps and pneumatic controllers evaluated the cost effectiveness of these sources independently, the shared usage of solutions for the two sources, such as compressed air systems, solar-powered systems, or generators, will result in even lower overall site-wide cost effectiveness values.

Under the previous approach in which EPA assessed each pump on an individual basis, the installation or replacement of a pneumatic pump would have resulted in the pump being a new source and an affected facility subject to NSPS OOOOb. In 40 CFR 60.14(a), modification is defined as "any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant." In order to clarify what constitutes a

modification for the collection of all pneumatic pumps at a site, the supplemental proposed rule specifies that if one or more pneumatic pumps is added to the site such that the total number of pumps increases, such addition constitutes a modification because it represents a physical change that results in an increase in emissions. Therefore, the collection of pneumatic pumps at the site would become a pneumatic pump affected facility. The EPA believes that owners and operators will implement zero-emission pumps across a site when a modification occurs because converting a single zero-emitting device typically requires a conversion of all devices at the facility. The EPA solicits comment on the ways in which a modification to a pneumatic pump affected facility would occur in light of the affected facility definition proposed herein, which includes the collection of all natural gas-driven pneumatic pumps at a site.

Analogous to the discussion above regarding reconstruction for pneumatic controllers in section IV.D.1.b.i, the definition of the pneumatic pump affected facility is the collection of natural gas-driven pneumatic pumps at a site. As with pneumatic controllers, the cost that would be required to construct a “comparable entirely new facility” under 40 CFR 60.15(b)(1) would be the cost of replacing all existing pumps with new pumps. Because individual pumps are likely to have comparable replacement costs, it is reasonable to assume that there would be a one-to-one correlation between the percentage of pumps being replaced at a site and the percentage of the fixed capital cost that would be required to construct a comparable entirely new facility.

Accordingly, we are proposing to include a second, simplified method of determining whether a pump replacement project constitutes reconstruction under 40 CFR 60.15(b)(1) whereby reconstruction may be considered to occur whenever greater than 50 of the number of existing onsite pumps are replaced.¹⁵⁹ As with controllers, the EPA believes that allowing owners or operators to determine reconstruction by counting the number of pumps replaced is a more straightforward option than requiring owners and operators to provide cost estimate information. By providing this

option, the EPA intends to reduce the administrative burden on owners and operators, as well as on the implementing agency reviewing the information. Owners and operators would be able to choose whether to use the cost-based criterion or the proposed number-of-pumps criterion. No matter which option an owner or operators chooses to use, the remaining provisions of 40 CFR 60.15 apply—namely, 40 CFR 60.15(a), the technological and economical provision of 40 CFR 60.15(b)(2), and the requirements for notification to the Administrator and a determination by the Administrator in 40 CFR 60.15(d), (e) and (f). The EPA is proposing that the standard in 40 CFR 60.15(b)(1) specifying that the “fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility” can be met through a showing that 50 percent or more of the number of existing onsite pumps are replaced. Therefore, upon such a showing, an owner or operator may demonstrate compliance with the remaining provisions of 40 CFR 60.15 that reference the “fixed capital cost” criterion.

The same logic and rationale discussed above in section IV.D.1.b.i for applying a 2-year rolling aggregation period for controller replacements also applies for pneumatic pumps. Therefore, we are proposing the same 2-year rolling period as the appropriate aggregation period to define a proposed replacement program time frame. Thus, the EPA proposes to count toward the greater than 50 percent reconstruction threshold all pumps replaced pursuant to all continuous programs of reconstruction which commence (but are not necessarily completed) within any 2-year rolling period following proposal of these standards. In the Administrator’s judgment, the 2-year rolling period provides a reasonable method of determining whether an owner of an oil and natural gas site with pneumatic pumps is actually proposing extensive controller replacement, within the EPA’s original intent in promulgating 40 CFR 60.15. As explained in greater detail in section IV.D.1.b.i, the EPA is soliciting comment on several aspects of the proposed reconstruction definition for pneumatic pumps and pneumatic controllers and refers commenters to that section for a description of the specific information requested.

The following scenarios are examples of the application of these proposed requirements for a site with access to electricity that has four natural gas-

driven pneumatic pumps. Scenario 1—One of the four pumps is replaced at any given time. The collection of pumps at the site would not be a pneumatic pump affected facility as this action is not a modification or reconstruction. Scenario 2—Three of the four pumps are replaced at the same time. This would constitute reconstruction (replacement of greater than 50 percent of the pumps), so the four pumps (*i.e.*, the “collection” of pumps at the site) would be a pneumatic pump affected facility. This affected facility would then be subject to the zero emissions standard, meaning that all pumps at the site, including the three new pumps and the one existing pump, cannot be driven by natural gas. Under Scenario 2, the one existing pump would need to be replaced or converted so that it is not powered by natural gas. Scenario 3—one pneumatic pump is replaced in February and two more are replaced in December of the same year. This would represent reconstruction (because more than 50 percent of the total number of pumps are being replaced over a 2-year period), so the four pumps (*i.e.*, the “collection” of pumps at the site) would be a pneumatic pump affected facility at the time the two pumps were replaced in December. This affected facility would then be subject to the zero-emissions standard, meaning that all four pumps would not be allowed to be driven by natural gas. Scenario 4—An additional pneumatic pump is added at any given time. This addition would represent a modification since it represents a physical change and would result in an increase in emissions. The five pumps would be a pneumatic pump affected facility and all five pumps would need to be powered in a manner other than natural gas.

ii. Changes to the Standard

As discussed above, we solicited comment in the November 2021 proposal on two key issues related to the proposed standard and BSER determination. These were: (1) An approach that would involve subcategorizing pneumatic pumps located at production and transmission and storage segments based on availability of electricity, and then developing separate standards for each subcategory, and (2) the technical feasibility of using pneumatic pumps not powered by natural gas at sites without electrical power.

Regarding the first issue, several commenters supported the approach of subcategorizing based on access to electrical power, and then determining BSER for pneumatic pumps separately for sites with and without access to

¹⁵⁹ Adding this method of determining “reconstruction” for pneumatic pumps is in accordance with 40 CFR 60.15(g), which states that “[i]ndividual subparts of this part [“Reconstruction”] may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.”

electrical power. One of these commenters noted that the availability of electricity is a significant and constraining factor that is within the EPA's authority to consider in subcategorization.¹⁶⁰

The comments were mixed concerning the feasibility of options that do not use natural gas-driven pneumatic pumps at remote sites without access to electrical power. Several commenters maintain that zero-emission pneumatic pumps are technically infeasible at sites without electricity. For example, one commenter who voiced support for the use of non-natural gas driven pumps as an option at sites where it is technically feasible indicated that requiring these pumps at many of their remote sites would be "burdensome at best and would force site shutdown in many cases."¹⁶¹ Another commenter stated that onsite solar generation paired with battery storage as an alternative to grid electricity systems are currently uncommon and unreliable. According to the commenter, use of these systems would likely increase the frequency of facility upsets, which would increase safety risks such as overpressure events and spills. The commenter concluded that onsite solar should therefore not be deemed an available technology.¹⁶² Other commenters provided specific examples of where pneumatic pumps not driven by natural gas, particularly solar-powered pumps, would likely not be technically feasible. Examples of the situations cited included locations with very cold temperatures, extended periods of cloud cover, and heavy snow load.

However, many commenters reported that options that do not use natural gas-

driven pneumatic pumps are available at sites without access to grid electricity systems, and that their use has been demonstrated. One of these commenters noted that in addition to solar-powered pumps, thermal electric generators or methanol fuel cells have been used to increase power at sites with high demand.¹⁶³ Another commenter is aware of retrofits at remote locations that have no electrical power in which natural gas is used to generate electricity to run pumps directly or to power air compressors that drive pneumatic pumps.¹⁶⁴ The EPA is requesting information regarding the characteristics of sites where thermal electric generators, methanol fuel cells, or other means to boost power for solar driven pneumatic pumps are needed. The EPA is also interested in costs for those systems.

Two commenters, who are also equipment vendors, confirmed the successful implementation of technologies to utilize pneumatic pumps not driven by natural gas at remote locations without the access to the grid. One has deployed solar-driven pneumatic pumps and air compressors in many states throughout the southwestern and northwestern U.S., including a remote location in Wyoming that experienced temperatures down to minus 11 degrees Centigrade (°C).¹⁶⁵ The second vendor reported that their standalone power generators have been deployed at a number of sites across the country to power pneumatic pumps.¹⁶⁶

In our analysis for the November 2021 proposal, we evaluated the costs and impacts of electric pumps run from the grid, solar-powered pumps, and compressed air systems to power the

pumps. No significant comments were received on this 2021 analysis; therefore, the essential elements of the analysis and results remain the same.

Baseline Emissions. The baseline emission estimates were calculated assuming a bleed rate of 2.48 scfh for natural gas-driven piston pumps and 22.45 scfh for natural gas-driven diaphragm pumps. Based on these natural gas bleed rates, assuming that natural gas bleeds from the pump for 8,760 hours per year and using the segment-specific gas compositions developed during the 2012 NSPS, the baseline emissions were estimated as provided in Table 21. More information on these calculations is provided in the Technical Support Document for this rulemaking.

The baseline emission analysis was conducted for six representative sites: (1) A single diaphragm pump, (2) a single piston pump, (3) one diaphragm pump and one piston pump, (4) two diaphragm pumps and two piston pumps, (5) 10 diaphragm pumps and 10 piston pumps, and (6) 50 diaphragm pumps and 50 piston pumps. All representative sites were not evaluated for all three sectors, as it is not expected that they would be applicable. Specifically, the two largest sites with 10 and 100 total pumps were not evaluated for the production and transmission and storage segments. For the processing plant segment, since it is expected that multiple pumps would be at each site, only representative sites 4, 5, and 6 were evaluated. The following table provides the baseline emissions for each type of representative facility.

TABLE 29—BASELINE PNEUMATIC PUMP EMISSIONS (TONS PER YEAR) FOR REPRESENTATIVE SITES

Rep Site #	# of Pumps		Production		Processing		Transmission/storage	
	Diaphragm	Piston	Methane	VOC	Methane	VOC	Methane	VOC
1	1	0	3.46	0.96	n/a		4.5	0.125
2	0	1	0.38	0.11	n/a		0.50	0.014
3	1	1	3.84	1.07	n/a		5.0	0.14
4	2	2	7.68	2.14	7.68	2.14	10.0	0.28
5	10	10	n/a		38.4	10.7	n/a	
6	50	50	n/a		192.0	53.4	n/a	

Cost Analysis for Options That Do Not Use Natural Gas-Driven Pneumatic Pumps. The EPA evaluated the following pump options that do not use

natural gas: electric pumps, solar-powered pumps, and instrument air systems that produce compressed air to power the pumps. All three options

were evaluated for pneumatic pumps in the production and transmission and storage segments. For the processing segment, only instrument air systems

¹⁶⁰ See Document ID No. EPA-HQ-OAR-2021-0317-0938.

¹⁶¹ See Document ID No. EPA-HQ-OAR-2021-0317-0463.

¹⁶² See Document ID No. EPA-HQ-OAR-2021-0317-0793.

¹⁶³ See Document ID No. EPA-HQ-OAR-2021-0317-0844.

¹⁶⁴ See Document ID No. EPA-HQ-OAR-2021-0317-0765.

¹⁶⁵ See Document ID No. EPA-HQ-OAR-2021-0317-0838.

¹⁶⁶ See Document ID No. EPA-HQ-OAR-2021-0317-0823.

were evaluated because it is expected that all processing plants have access to electrical power and have multiple pumps at the site.

The following paragraphs provide the estimated costs for electric pumps, solar-powered pumps, and instrument air systems. The EPA is not aware of differences between the oil and natural gas industry segments that would result in the different costs for these options between segments. These paragraphs provide capital costs and total annual costs. For all of these options, the capital recovery cost component of the annual cost is based on a 7 percent interest rate and an equipment life of 10 years.

The capital and installation cost of an electric pump using electricity from the grid is estimated to be \$5,219. The total annual costs, including capital recovery and an estimated operation and maintenance cost of \$329 per year, yields a total annual cost per electric pump of \$1,072.

For solar-powered pumps, the estimated capital cost, including installation, is \$2,501 per pump. It is assumed that the annual operation and maintenance is no greater than a natural gas-driven pump, so the total annual cost is the capital cost of \$356 per year.

For electric pumps and solar-powered pumps, the cost information is assessed on an individual pump basis. While it is expected that the cost per pump

would be less where there are more pumps on site, we do not have information on these cost advantages. Therefore, our estimate of the site-wide costs and emission reductions would simply be the multiple of our per pump costs and emission reductions multiplied by the number of pumps at the site. Thus, the cost effectiveness for representative sites 3 and 4 is the same. The EPA is requesting information on the costs of site-wide electric and solar-powered pump solutions.

Instrument air system costs were estimated for small, medium, and large compressors. The small compressor was assumed to have an air capacity of 135 scfh, while the medium and large had capacities of 562 and 1,350 scfh, respectively. The estimated capital (including installation) costs for these three sizes of instrument air systems are \$6,742 for the small system, \$33,699 for the medium system, and \$59,308 for the large system. The estimated annual costs, including capital recovery, labor for operation and maintenance, and electricity, are \$11,295 for the small system, \$36,264 for the medium system, and \$81,350 for the large system. In the estimation of impacts for the representative sites described above, the small system costs were used for representative sites 1, 2, 3, and 4; the medium system for representative site 5; and the large system for representative site 6.

Since all of these options do not use natural gas to drive the pneumatic pump, their use results in a 100 percent reduction in methane and VOC emissions from the baseline levels shown in Table 21 above. Using the annual total annual costs and these emission reductions, we calculated the cost effectiveness for each zero-emission option for each representative site. Cost effectiveness was calculated on a single pollutant basis, where the total annual cost was applied entirely to the reduction of each pollutant. Cost effectiveness was also calculated on a multi-pollutant basis, where half the cost of control is assigned to the methane reduction and half to the VOC reduction.

The estimated cost effectiveness values for the options that do not use natural gas-driven pneumatic pumps are provided in Table 30. In addition to the cost effectiveness values, Table 30 provides a conclusion as to whether the estimated cost effectiveness value is within the range that the EPA has typically considered to be reasonable. The “overall” reasonableness determination is classified as “yes” if the cost effectiveness of either methane or VOC is within the range that the EPA considers reasonable for that pollutant, or if both the methane and VOC cost effectiveness values are without the range that the EPA considers reasonable on a multipollutant basis.

TABLE 30—SUMMARY OF COST EFFECTIVENESS FOR PNEUMATIC PUMP OPTIONS THAT DO NOT USE PUMPS DRIVEN BY NATURAL GAS

Segment Option— Representative Site	Cost Effectiveness (\$/ton) ^a —Reasonable?				Overall ^a
	Single pollutant		Multipollutant		
	Methane	VOC	Methane	VOC	
Production Segment:					
Electric Pumps— Single Dia- phragm.	\$310–Y	\$1,115–Y	\$115–Y	\$557–Y	Y
Electric Pumps— Single Piston.	1,632–Y	5,869–Y	816–Y	2,934–Y	Y
Electric Pumps— Multiple Pumps ^b .	441–Y	1,585–Y	220–Y	793–Y	Y
Solar Pumps—Sin- gle Diaphragm.	103–Y	370–Y	51–Y	185–Y	Y
Solar Pumps—Sin- gle Piston.	937–Y	3,371–Y	469–Y	1,686–Y	Y
Solar Pumps—Mul- tiple Pumps ^b .	185–Y	667–Y	93–Y	334–Y	Y
Instrument Air— Single Dia- phragm.	3,264–N	11,743–N	1,632–Y	5,871–Y	Y
Instrument Air— Single Piston.	29,724–N	106,921–N	14,682–N	53,461–N	N
Instrument Air—1 Diaphragm/1 Pis- ton.	2,941–N	10,581–N	1,471–Y	5,290–Y	Y
Instrument Air—2 Diaphragm/2 Pis- ton.	1,471–Y	5,290–Y	735–Y	2,645–Y	Y

TABLE 30—SUMMARY OF COST EFFECTIVENESS FOR PNEUMATIC PUMP OPTIONS THAT DO NOT USE PUMPS DRIVEN BY NATURAL GAS—Continued

Segment Option— Representative Site	Cost Effectiveness (\$/ton) ^a —Reasonable?				Overall ^a
	Single pollutant		Multipollutant		
	Methane	VOC	Methane	VOC	
Processing Segment:					
Instrument Air—2 Diaphragm/2 Piston.	1,471–Y	5,290–Y	735–Y	2,645–Y	Y
Instrument Air—10 Diaphragm/10 Piston.	944–Y	3,397–Y	472–Y	1,699–Y	Y
Instrument Air—50 Diaphragm/50 Piston.	424–Y	1,524–Y	212–Y	762–Y	Y
Transmission and Storage Segment:					
Electric Pumps—Single Diaphragm.	237–Y	8,563–N	119–Y	4,281–Y	Y
Electric Pumps—Single Piston.	1,249–Y	45,083–N	624–Y	22,541–N	Y
Electric Pumps—Multiple Pumps ^b .	337–Y	12,177–N	169–Y	6,088–N	Y
Solar Pumps—Single Diaphragm.	79–Y	2,844–Y	39–Y	1,422–Y	Y
Solar Pumps—Single Piston.	717–Y	25,897–N	359–Y	12,948–N	Y
Solar Pumps—Multiple Pumps ^b .	142–Y	5,125–Y	71–Y	2,563–Y	Y
Instrument Air—Single Diaphragm.	2,499–N	90,206–N	1,249–N	45,103–N	N
Instrument Air—Single Piston.	22,751–N	821,348–N	11,376–N	410,674–N	N
Instrument Air—1 Diaphragm/1 Piston.	2,251–N	81,279–N	1,126–Y	40,640–N	N
Instrument Air—2 Diaphragm/2 Piston.	1,126–Y	40,640–N	563–Y	20,320–N	Y

^aFor the production and processing segments, the owners and operators realize the savings for the natural gas that was not emitted and lost. The cost effectiveness values shown do not consider these savings. Note that the consideration of savings does not impact whether the cost effectiveness of any of these options falls within the ranges considered reasonable by the EPA.

^bFor overall cost effectiveness to be considered reasonable, either the cost effectiveness of methane or VOC on a single pollutant basis must be within the ranges considered reasonable by the EPA, or the cost effectiveness of both methane and VOC on a multipollutant basis must be within the ranges considered reasonable by the EPA.

^cFor multiple pump scenarios, an equal number of diaphragm and piston pumps is assumed.

While the costs for electric pumps and instrument air systems assume access to electrical power (that is, access to the grid), solar-powered pumps can be utilized at many remote sites that do not have access to electrical power. Instrument air systems can also be utilized at sites without access to the electricity grid but would require the installation and operation of a generator. These generators could be powered by engines fueled by solar energy, natural gas, or diesel. While such systems are technically a viable option at these remote sites, we did not have detailed cost information available to include these systems in our analysis. One commenter provided estimated costs ranging from \$60,000 to over \$200,000

for an instrument air system driven by a natural gas generator.¹⁶⁷ The commenter also provided an estimate of \$250,000 for an instrument air system powered by solar energy. However, the focus of the comments and these cost estimates was pneumatic controllers, not pumps. The EPA is specifically requesting information on whether these costs are representative of systems that could be used to power compressed air-driven pneumatic pumps, as well as comments on whether a single generator or solar system could be used to power both pneumatic controllers and pneumatic pumps.

¹⁶⁷ See Document ID No. EPA–HQ–OAR–2021–0317–0808.

Proposed BSER Conclusion. As demonstrated in the analysis, there are pneumatic pump options that do not use natural gas for which the cost effectiveness is within the ranges considered to be reasonable by the EPA. These types of pumps can be utilized at sites with access to grid electricity as well as at remote sites that do not have this access.

This BSER conclusion is consistent with the EPA's findings in 2021. However, at that time we were unable to conclude that pumps that do not use natural gas represented BSER due to our inability to conclude that technical limitations previously identified had been overcome. As summarized above, several commenters continue to

maintain that there are significant technical limitations, particularly with solar-powered pneumatic pumps. However, other commenters provided evidence that pneumatic pumps not driven by natural gas are available and in use in the industry.

Under CAA Section 111(b), the EPA must determine that the BSER has been “adequately demonstrated.” The EPA concludes that pneumatic pump systems that do not use natural gas have met this standard at sites both with and without access to grid electricity. In addition, as discussed above, we have concluded that there are system options available at sites in all segments of the industry that have cost effective values considered reasonable by the EPA.

Secondary impacts from these non-natural gas-driven pumps, particularly from the use of instrument air systems, are indirect, variable, and dependent on the electrical supply used to power the compressor. The secondary impacts resulting from the increase in electricity needed from the grid to power compressors for instrument air were discussed above for pneumatic controllers. These also represent the impacts that would occur for compressors used to provide instrument air for pneumatic pumps. However, a single compression system, appropriately sized, could power both pneumatic controllers and pumps at a site, meaning that the electricity usage and resulting secondary impacts would not necessarily be doubled. No other secondary impacts are expected.

In light of the above, we find that the BSER for reducing methane and VOC emissions from natural gas-driven piston and diaphragm pumps at all segments of the industry is the use of pneumatic pumps that do not use natural gas as a driver. This option results in a 100 percent reduction of direct emissions for both methane and VOC, or zero methane and VOC emissions. Therefore, for NSPS OOOOb, we are proposing to require a natural gas emission rate of zero for all pneumatic pumps in the source category.

One request for comments that the EPA solicited in November 2021 was related to the potential subcategorization of pumps based on access to grid electrical power. Because we have determined that the requirement to use zero-emission pumps that are not powered by natural gas is BSER for all sites, regardless of whether the site has access to electrical power, we have decided that subcategorization is not necessary.

Technical Infeasibility Situations.

While we conclude that zero-emission pneumatic pumps not powered by

natural gas are adequately demonstrated as BSER, we understand that there may be specific conditions at sites without access to electricity that result in situations where it may be technically infeasible to utilize a non-natural gas-driven pump. Therefore, we also analyzed alternatives that could be incorporated into NSPS OOOOb in these instances. Note that because we have concluded that it should always be technically feasible for sites with access to electricity to utilize zero-emission pneumatic pumps that are not driven by natural gas, these alternatives would only be available at sites that do not have access to electricity.

First, we analyzed capturing the natural gas emissions from the pneumatic pump through venting and routing them to an existing process. The costs associated with this option are a capital cost of \$6,102 with an annual cost of \$869 (capital recovery using 7 percent interest for 10 years). The cost effectiveness for a single diaphragm pump in the production segment, assuming 100 percent capture, was \$251 per ton of methane removed (\$79 per ton with savings) and \$903 per ton of VOC removed (\$284 per ton with savings). On a multipollutant basis, these cost effectiveness values were \$126 per ton of methane (\$39 per ton with savings) and \$452 per ton of VOC (\$142 per ton with savings). For a single piston pump, the cost effectiveness was \$2,286 per ton of methane removed (\$2,114 with savings) and \$8,224 per ton of VOC (\$7,604 with savings). On a multipollutant basis, these cost effectiveness values were \$1,143 per ton of methane (\$1,057 per ton with savings) and \$4,112 per ton of VOC (\$3,802 per ton with savings).

For the representative site 3 (with one diaphragm piston and one piston pump), the single pollutant cost effectiveness values were \$226 per ton of methane reduction (\$54 with savings) and \$814 per ton of VOC reduction (\$194 with savings). The multipollutant cost effectiveness values were \$113 per ton of methane reduction (\$27 with savings) and \$407 per ton of VOC reduction (\$97 with savings).

All of these cost effectiveness values for both methane and VOC are within the ranges considered reasonable by the EPA, with the exception of the single pollutant cost effectiveness values for methane and VOC for a piston pump. However, since the multipollutant cost effectiveness of both methane and VOC were in the range considered acceptable by the EPA for a site with a single piston pump, we determined that this is an acceptable option.

For the transmission and storage segment, the cost effectiveness for a single diaphragm pump was \$192 per ton of methane removed and \$40,640 per ton of VOC. On a multipollutant basis, these cost effectiveness values were \$96 per ton of methane and \$20,320 per ton of VOC. For a single piston pump, the cost effectiveness was \$1,750 per ton of methane removed and \$26,095 per ton of VOC. On a multipollutant basis, these cost effectiveness values were \$875 per ton of methane and \$13,048 per ton of VOC. For the representative site with one diaphragm piston and one piston pump, the single pollutant cost effective values were \$173 per ton of methane reduction and \$11,708 per ton of VOC reduction, and the multipollutant cost effectiveness values were \$87 per ton of methane reduction and \$5,854 per ton of VOC reduction.

All of the cost effectiveness values for methane on a single pollutant basis are within the ranges considered reasonable by the EPA. In addition, the multipollutant cost effectiveness for both methane and VOC were in the ranges considered reasonable by the EPA for a site with one diaphragm and one piston pump.

In conclusion, because we believe that routing to a process is a viable and cost-effective option for pneumatic pumps when it is technically infeasible to use a zero-emission pneumatic pump not driven by natural gas, this option is included in the proposed NSPS OOOOb. In order to utilize this option, an owner or operator must demonstrate technical infeasibility. In addition, because the CVS system that collects and routes these emissions to a process could develop leaks, the proposed NSPS OOOOb requires compliance with the CVS no-detectable leaks requirements specified in 40 CFR 60.5411b(a) and (c) of the proposed regulatory text.

The EPA is interested in several aspects related to the option of collecting the pneumatic pump emissions and routing them to a process. First, we are soliciting information that describes specific situations where owners and operators have utilized this option to use, rather than lose, the valuable natural gas emitted from pneumatic pumps. We are interested in gathering information on the specific processes and types of equipment that are needed to do so, as well as information on the related costs. We are also interested in information to support our understanding that routing to a process achieves a 100 percent reduction in emissions. This understanding is based on the fact that the gas that is emitted from pneumatic

pumps is drawn directly from the raw product gas stream that will be collected and routed to a gathering and boosting station and eventually to a natural gas processing plant (*i.e.*, the gas “sales line”). Therefore, the emissions from the pneumatic pumps are of the same composition as the gas in the sales line. Since the emissions are at atmospheric pressure, it is likely that the gas would need to be compressed prior to re-introduction to the sales line. We do not expect that this compression would result in emissions. Similarly, since the composition of these emissions is typically high in methane, the heat content would make it amendable to being used as fuel, or introduced with the primary fuel stream for use in an engine without the need for additional processing that could result in emissions.

This request for information includes information on the installation of VRUs. Note that the analysis above did not include the installation of a new VRU. As discussed in section IV.D.1.b.iii for pneumatic controllers, we do not believe that a VRU would be needed to enable the use of the emissions from pneumatic pumps (in contrast to emissions from storage vessels and centrifugal compressor wet seal fluid degassing systems). Despite this belief, in the analysis for the November 2021 proposal, we did analyze the costs to install a new VRU to process the emissions from pneumatic pumps to enable the routing to a process. We determined that these costs were unreasonable, given the emission reductions. One commenter felt that our VRU costs were inflated. We are interested in learning about situations where a VRU would be needed to enable the use of emissions from a pneumatic pump in a process, as well as the costs of those VRUs.¹⁶⁸ These costs are included in the November 2021 TSD.

We also recognize that there could be situations at sites without access to electricity where not only is it technically infeasible to utilize zero-emission pneumatic pumps that are not driven by natural gas, but it is also technically infeasible to route the emissions to a process. Therefore, we also considered the option to route to a control device. The analysis conducted for the November 2021 proposal concluded that while it was reasonable to route the emissions from a pneumatic pump to an existing control device, the cost effectiveness of installing a new control device dedicated to the pneumatic pump was higher than the

EPA considers reasonable. This finding is still valid for this proposal for sites with a single pneumatic pump. However, as noted above, the EPA changed the pneumatic pump affected facility definition for this proposal to be the collection of natural gas pneumatic pumps at a site. Therefore, we updated the analysis to consider the cost effectiveness of installation of a new control device that would control emissions from multiple natural gas-driven pneumatic pumps.

This analysis found that where there are four or more natural gas-driven pneumatic diaphragm pumps at a site, the cost effectiveness of a new combustion device that reduces emissions by 95 percent from all the pumps is within the ranges considered reasonable by the EPA. For the production segment, the cost effectiveness values for a site with four diaphragm pumps are \$1,869 per ton of methane reduced and \$6,723 per ton of VOC reduced on a single pollutant basis. On a multipollutant basis, these values are \$934 per ton of methane and \$3,361 per ton of VOC. Therefore, these cost effectiveness values are considered reasonable for methane on a single pollutant basis as well as on a multipollutant basis. For the transmission and storage segment, the single pollutant methane cost effectiveness was \$1,430, which is in the range considered reasonable by the EPA.

Therefore, the proposed NSPS OOOOb includes the requirement for production and transmission and storage sites as follows: if an owner or operator demonstrates that it is technically infeasible to install zero-emission non-natural gas-driven pumps, and it is technically infeasible to route to a process, the emissions must be routed to a control device to achieve 95 percent reduction of the methane and VOC if the pneumatic pump affected facility includes four or more diaphragm pumps. Note that emissions from all piston pumps at the site would also be required to be reduced by 95 percent. For pneumatic pump affected facilities with less than four diaphragm pumps, where it has been demonstrated that it is technically infeasible to use zero-emission non-natural gas-driven pumps and infeasible to route to a process, the proposed NSPS OOOOb mirrors the November 2021 proposal. That is, the pneumatic pump emissions must be routed to an existing control device (if one is available) to achieve 95 percent reduction.

There are several instances in this hierarchical structure of the proposed NSPS OOOOb where less stringent

requirements may apply if it is determined that the more stringent requirement is technically infeasible. The proposed rule requires that these demonstrations be made by a qualified professional engineer or an in-house engineer with relevant expertise. While several commenters stressed that in-house engineers should be allowed to make required certifications and determinations, other commenters expressed concerns that only certified professional engineers should be allowed to certify technical infeasibility. The EPA concluded that the flexibility to allow in-house engineers to make these determinations and certifications is warranted, especially given the potential shortage of professional engineers with specific expertise required for these determinations (that is, expertise in solar-powered pneumatic pumps or routing pneumatic pump emissions to a process).

However, the EPA is also committed to ensuring that this technical infeasibility provision is not abused or used as a loophole to avoid implementing important pollution reduction measures. The EPA stresses that each technical infeasibility determination must be documented, and the following statement submitted to the EPA (or delegated enforcement authority): “I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted, and this report was prepared, pursuant to the requirements of 40 CFR 60.5393b(c)(1). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.” The EPA wants to make it clear that in the case that such a certification is determined by the Agency to be fraudulent, or significantly flawed, not only will the owner or operator of the affected facility be in violation of the standards, but the person that makes the certification will also be subject to civil and potentially criminal penalties.

c. Summary of Proposed NSPS OOOOb

The proposed NSPS OOOOb defines a pneumatic pump affected facility as the collection of natural gas-driven diaphragm and piston pneumatic pumps at all types of sites throughout the production, processing, and transmission and storage segments of the source category. Specifically, these sites include well sites, centralized production facilities, onshore natural gas processing plants, and compressor stations. Pneumatic pumps that are not driven by natural gas are not included

¹⁶⁸ See Document ID No. EPA-HQ-OAR-2021-0317-0844.

in the proposed pneumatic pump affected facility as long as records are maintained to verify that non-natural gas-driven pumps are used.

Natural gas-driven pumps that are in operation less than 90 days per calendar year are not part of an affected facility provided that the owner or operator keeps records of the days of operation each calendar year and submits such records to the EPA (or delegated enforcement authority) upon request. Any period of operation during a calendar day counts toward the 90-calendar day threshold.

In addition to the modification definition in 40 CFR 60.14 and the reconstruction definition in 40 CFR 60.15, the proposed rule includes clarification of these terms for the pneumatic pump affected facility. A modification occurs when the number of natural gas-driven pneumatic pumps at a site is increased by one or more, and reconstruction occurs when either the cost of the pumps being replaced exceeds 50 percent of the cost to replace all the pumps, or when 50 percent or more of the pneumatic pumps at a site are replaced.

The proposed BSER is the use of pneumatic pumps not powered by natural gas; the proposed standard of performance is zero emissions of methane and VOC. As noted above, compliance with this standard effectively eliminates the existence of a pneumatic pump affected facility (which is a natural gas-driven pump or collection of pumps, by definition). For sites in the production or transmission and storage segment of the industry who do not have access to electricity, the proposed standards include a hierarchical structure that allows the use of natural gas-driven pneumatic pumps based on the technical feasibility of pneumatic pump control measures. This hierarchy is not available to natural gas processing plants, as the only proposed requirement is the use of non-natural gas-driven pneumatic pumps at these sites.

If it is demonstrated that it is technically infeasible to utilize a pneumatic pump not driven by natural gas at a site in the production or transmission and storage segment of the industry which does not have access to electricity, compliance may be achieved by collecting methane and VOC emissions from all pumps (diaphragm and piston pumps) in the affected facility via a CVS and routed to a process, which we understand results in 100 percent emissions reductions. The CVS is required to comply with the CVS requirements specified in 40 CFR 60.5411b(a) and (c) of the proposed

regulatory text, which includes certification by a professional or in-house engineer that the CVS was designed properly and was operated in accordance with the no detectable emissions provisions. For this “tier one” technical infeasibility determination, a demonstration must be made that using a solar-powered electric pneumatic pump is not technically feasible. This demonstration must be certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of solar-powered pneumatic pumps. Alternatively, this demonstration can be certified by a solar-powered pneumatic pump manufacturer that has successfully installed solar-powered pneumatic pumps at other oil and natural gas sites. In addition, the tier one technical infeasibility demonstration must prove that it is not technically feasible to install a compressed air system powered by either a natural gas-driven generator or a solar-powered generator. This demonstration must include, but not be limited to, the ability to operate a generator, including access to natural gas; access to solar power; or the inability of a compressed air system to power the pneumatic pump. This demonstration must be certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of natural gas-driven or solar-powered generators to power pneumatic pumps. In addition to the records associated with the technical infeasibility determination/certification, a record of the certification of the design of the CVS must be maintained, along with records of all inspections required to demonstrate compliance with the no detectable emissions requirements.

If it is demonstrated that it is technically infeasible to collect the emissions from all pneumatic pumps in the affected facility and route them to a process (in addition to the demonstration that it is infeasible to utilize a pneumatic pump not driven by natural gas), compliance may be achieved by collecting methane and VOC emissions from all pumps (diaphragm and piston pumps) in the affected facility via a CVS and routing them to a control device that achieves 95 percent reduction in methane and VOC emissions. The CVS would be subject to the design requirements, specified in 40 CFR 60.5411b(a) and (c) of the proposed regulatory text, and must comply with the no detectable emissions requirements. The control device would be subject to testing and

continuous monitoring requirements. This “tier two” demonstration must include, but is not limited to, safety considerations, distance from a process, pressure losses and differentials which impact the ability of the process to handle all the pneumatic pump affected facility emissions routed to it, or other technical reasons the process cannot handle all the pneumatic pump affected facility emissions routed to it. This demonstration must be certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of the pneumatic pump affected facility and the process to which emissions will be routed. A demonstration of technical infeasibility may not be based on the infeasibility of the design and operation of CVS to collect emissions from all the pneumatic pumps in the affected facility. In addition to the records associated with both technical infeasibility determinations and certifications, a record of the certification of the design of the CVS must be maintained, along with records of all inspections required to demonstrate compliance with the no detectable emissions requirements. Records must also be maintained of either the performance testing of the control device (whether at the site or by the manufacturer), or records demonstrating compliance with 40 CFR 60.18 General Provisions flare requirements. Finally, monitoring records must be maintained to demonstrate that the control device is operating properly on a continuous basis.

“Tier three” of the hierarchy applies if there are less than four natural gas-driven diaphragm pumps at a site. In this situation, the owner or operator is not required to install a new control device. The proposed standard for the pneumatic pump affected facilities at sites with less than four diaphragm pumps mirror those proposed in the November 2021 proposal, which require that methane and VOC emissions be reduced by 95 percent by routing to an existing control device if: (1) A control device is onsite, (2) the control device can achieve a 95 percent reduction, and (3) it is technically feasible to route the emissions to the control device. However, the proposed rule would exempt an owner or operator from this requirement provided that they document the technical infeasibility of routing the emissions to an existing control device and submit it in an annual report. Similarly, where it is feasible to route the emissions to a control device, but the control cannot

achieve 95 percent reduction, the proposed rule would exempt the owner or operator from the 95 percent reduction requirement, provided that the owner or operator maintain records demonstrating the percentage reduction that the control device is designed to achieve.

The EPA notes that inherent throughout these proposed pneumatic pump requirements are demonstrations of technical infeasibility. Each technical infeasibility determination must include a certification, signed and dated by the qualified professional engineer or in-house engineer. The EPA wants to make it clear that in the case that such a certification is determined by the Agency to be fraudulent, or significantly flawed, not only will the owner or operator of the affected facility be in violation of the standards, but the person that makes the certification will also be subject to civil and potentially criminal penalties.

2. EG OOOOc

The proposed presumptive standards for methane emissions from existing pneumatic pumps mirror those described above for NSPS OOOOb. The EPA did not identify any circumstances that would result in a different BSER for existing sources under the EG OOOOc.

In light of the proposal to require zero-emission pneumatic pumps not powered by natural gas for both new and existing sources, the EPA would like to highlight comments and solicit related information. Commenters on the November 2021 proposal indicated that the proposed rules would exacerbate demand, increase costs, and increase pressure on the supply chain for zero-emissions systems. One commenter stated that reliability and availability of alternate zero-emission options (*i.e.*, solar-powered/battery backup systems, and electric, self-contained systems) are a major concern for safe and reliable operations.¹⁶⁹ Another commenter indicated that one of their members contacted a vendor within the last six months to find out how much deployment there has been of solar systems and electric controllers.¹⁷⁰ The commenter reported that the vendor indicated that in the past 10 years, they have conducted 200 retrofits and 300 new installs, and the vendor estimates that it can only service approximately 200 installs per year. Additionally, the commenter indicated that operators are already experiencing 6 to 12-month lead

times for delivery of solar packages. So that it may continue to gather information on this subject, the EPA is specifically requesting comment on the availability of pneumatic pump systems not powered by natural gas.

F. Wells and Associated Operations

1. Affected and Designated Facility Definitions

a. NSPS OOOOb

The November 2021 proposal had three separate affected facilities associated with oil and natural gas wells. These included: (1) The well completion affected facility, defined as a single well that conducts a well completion operation following hydraulic fracturing or refracturing; (2) the associated gas affected facility, defined as any oil well that produces associated gas; and (3) the well liquids unloading affected facility, with two proposed options for the definition. Under Option 1, a well liquids unloading affected facility was defined as every well that undergoes liquids unloading. Under Option 2, a well liquids unloading affected facility was defined as every well that undergoes liquids unloading using a method that is not designed to completely eliminate venting. Each of these three types of affected facilities included proposed definitions of what would constitute a modification to an oil and natural gas well. The result of including all three definitions would have been that a single well could have been three different affected facilities for three different emissions sources. In addition, a single well could have been a new source affected facility under NSPS OOOOb and a designated facility under EG OOOOc.

To eliminate the potential confusion from this complex regulatory structure, the EPA is proposing to change its approach as part of this proposed action. Rather than three separate well affected facilities, we are now proposing a definition of well affected facility, which is defined as a single well, in the proposed NSPS OOOOb. A well is defined as a hole drilled for the purpose of producing oil or natural gas. More discussion of the rationale for this revision specific to each of the three well operations is provided in sections IV.E.2, 3, and 4 below.

There are separate proposed standards for well completions, associated gas from oil wells, and gas well liquids unloading operations, all or some of which could apply to a well affected facility. These proposed standards and their applicability are discussed in more detail in sections IV.E.2, 3, and 4 of this

preamble. A well affected facility is only required to comply with the standards that are applicable to the well. For example, a gas well would not be subject to the oil well with associated gas standards. The proposed NSPS OOOOb specifies that a modification to an existing well occurs when the definition of modification in 40 CFR 60.14 is met, including when an existing well undergoes hydraulic fracturing or re-fracturing.

b. EG OOOOc

The November 2021 proposal only included the oil wells with associated gas designated facility, as the proposed definition of modification for the NSPS OOOOb well liquids unloading affected facility would have resulted in all wells that performed liquids unloading being new or modified sources. As discussed above and in section IV.E.3, the EPA has not retained the proposed well liquids unloading modification definition in this supplemental proposal. Therefore, this proposal includes standards for gas well liquids unloading at designated facilities in the proposed EG OOOOc. However, since the fracturing or re-fracturing of an existing well would constitute a modification under NSPS OOOOb, which makes the well a well affected facility under NSPS OOOOb, there would never be an existing well subject to completion requirements.

The well designated facility definition in EG OOOOc is now proposed to be defined as a single well and EG OOOOc would include presumptive standards for associated gas from oil wells and gas well liquids unloading.

2. Associated Gas From Oil Wells

a. NSPS OOOOb

i. November 2021 Proposal

Associated gas originates at wellheads that also produce hydrocarbon liquids and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon phase by separation. In the November 2021 proposal, the EPA proposed standards in NSPS OOOOb to reduce methane and VOC emissions resulting from the venting of associated gas from oil wells. Specifically, the November 2021 proposal would have required owners and operators of oil wells to route associated gas to a sales line. If access to a sales line was not available, the EPA proposed that the gas could have been used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent reduction of methane and VOC

¹⁶⁹ See Document ID No. EPA-HQ-OAR-2021-0317-0739.

¹⁷⁰ See Document ID No. EPA-HQ-OAR-2021-0317-0808.

emissions.¹⁷¹ The EPA also requested comment on whether to include re-injecting associated gas for enhanced oil recovery or another purpose should be included in the list of beneficial uses. The following sections provide discussions of the comments submitted on the November 2021 proposal, the changes resulting from these comments, and our rationale for the changes. Section IV.E.2.iii summarizes the resulting proposed requirements included in this supplemental proposal.

ii. Changes From November 2021 Proposal

The BSER determination for associated gas from oil wells was discussed in section XII.J.1.e of the November 2021 proposal (86 FR 63237–63238; November 15, 2021). The EPA did not receive any comments on the proposal that resulted in a change to the analysis that had concluded that BSER for associated gas from oil wells was the routing of the associated gas to a sales line.

In this action, we are proposing changes to the associated gas from the oil wells affected facility definition, the hierarchy of the standard, and the compliance options. In addition to proposed changes associated with these topics, a significant addition to the proposed rule is the establishment of requirements for situations when associated gas from an oil well that is primarily either routed to a sales line or used for another beneficial purpose is unable to utilize the gas in that manner due to gathering system or other disruptions. In addition, the EPA is soliciting additional information on potential emerging technologies that provide uses for the associated gas in a beneficial manner other than routing to a sales line, using as a fuel, or reinjecting the gas. Examples of such emerging technologies provided by commenters include methane pyrolysis¹⁷² and condensing the gas and transporting it to other sites for use.¹⁷³

Hierarchy of the Standard and Control Options. As discussed in section IV.E.1.b.i, the standard for associated gas from oil wells in the November 2021 proposal was to route the associated gas to a sales line. If access to a sales line was not available, the proposal allowed

the gas to be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent reduction in methane and VOC emissions.

The EPA specifically solicited comment on how “access to a sales line” should be defined. Several commenters¹⁷⁴ stated that access to a sales pipeline is based on numerous criteria that can be outside a well operator’s control. They indicated that, in most cases, the midstream company that designs, builds, and operates the gas gathering system (sales line) and gas processing plant is not the same as the well owner and operator, landowner, and mineral lease owner. Thus, commenters concluded that “access to a sales line” does not equate to availability to route gas into that sales line.

Commenters also objected to the overall construct of the proposal where the standard required the routing to a sales line in situations where access to sales line was available. They indicated that using the gas as an onsite fuel source should be an option that was allowed on an equal basis with routing to a sales line.

The EPA agrees with these commenters regarding the associated gas from oil wells standards. First, the EPA understands that the sales line is typically not under the control of the well owner, and that the gathering system owner dictates when gas can be routed to a sales line. We believe this understanding supports allowing other uses of associated gas, which also avoid methane and VOC emissions from venting or flaring of associated gas, as acceptable compliance options. Specifically, while BSER was determined to be routing to a sales line, we agree that beneficial uses of the associated gas should be allowed as these options are equivalent in terms of emission reduction to the identified BSER. Therefore, we are proposing to expand what is considered beneficial use to include options beyond routing to the sales line. This proposed rule would require any of the following options for beneficial use: (1) Routing associated gas from oil wells to a sales line; (2) using the associated gas as a fuel or for another useful purpose that a purchased fuel or raw material would serve; (3) or reinjecting the associated gas into the well or injecting the associated into another well for enhanced oil recovery.

Regarding re-injection, commenters indicated that re-injection should be included as one of the options allowed. One commenter stated that well operators may prefer to reinject associated gas. They pointed out that reinjection is used widely in Alaska, where 90 percent of associated gas is injected into oil-bearing formations. They concluded that reinjection as a method of gas capture has significant emissions reduction benefits, because it largely eliminates emissions of methane and other pollutants.¹⁷⁵

As noted above, commenters also mentioned examples of emerging techniques that provide additional beneficial uses of the associated gas, including compressing the gas and transporting it to a nearby processing plant or pipeline and methane pyrolysis. The EPA interprets the third criterion, “used for another useful purpose,” to include these emerging techniques but is soliciting comment whether an additional criterion should be added to make this clear. The EPA is also soliciting comment on more specific technologies that have been proven to be viable in the field to utilize associated gas and avoid venting or flaring.

Some commenters stated that the proposed rule would not succeed in ensuring that oil and gas operators will not flare associated gas in situations where other options were available, and these commenters opposed routine flaring as a compliance alternative on par with the non-sales line “beneficial” use options. They urged the EPA to abandon what they described as an “unworkable framing,” and instead suggested that the EPA adopt a BSER that would eliminate routine flaring except in specific and narrowly defined circumstances. We agree that flaring of the gas should only be allowed in situations where it is not feasible to route the associated gas to a sales line or use it for one of the other useful purposes described above. Therefore, this proposed rule would allow flaring of the associated gas only if the owner or operator certifies that it is not feasible to route the associated gas to a sales line or use it for another beneficial purpose due to technical or safety reasons. This demonstration would need to address the specifics regarding the lack of availability to a sales line, including efforts by operators to get access to a sales line or to facilitate alternative off-site transport and use of associated gas. The demonstration would also need to demonstrate why all potential beneficial

¹⁷¹ The EPA solicited comment on whether to also include re-injecting associated gas as an alternative (86 FR 63237; November 15, 2021) and based on comments in support of this option [EPA–HQ–OAR–2021–0317–0844], is including such alternative in this supplemental proposal.

¹⁷² See Document ID No. EPA–HQ–OAR–2021–0317–0594.

¹⁷³ See Document ID No. EPA–HQ–OAR–2021–0317–0558.

¹⁷⁴ See Document ID Nos. EPA–HQ–OAR–2021–0317–0793, EPA–HQ–OAR–2021–0317–0808, EPA–HQ–OAR–2021–0317–0911.

¹⁷⁵ See Document ID No. EPA–HQ–OAR–2021–0317–0844.

uses (including emerging techniques) are not feasible due to technical or safety reasons. The first demonstration would require certification by a professional engineer or other qualified individual and would be submitted in the first annual report for the well affected facility. In each subsequent annual report, the owner or operator would be required to report whether any circumstances had changed regarding the need to flare relative to the initial certification, and if so, which beneficial use would be applied to the associated gas.

The EPA recognizes that several states have adopted standards to further reduce routine flaring of associated gas, including Colorado and New Mexico. As noted above, several commenters also urged the EPA to take additional steps to eliminate routine flaring of associated gas, except in very limited cases such as emergencies or for safety reasons. Therefore, the EPA is taking comment on steps the Agency should consider taking to disallow the indefinite continuation of routine flaring. First, the EPA is taking comment on whether the ongoing annual requirement to report whether circumstances had changed regarding the need to flare should result in a need to perform a more thorough analysis and engineering certification comparable to the initial certification required once an owner or operator becomes subject to the rule. For example, it may be appropriate to require an owner or operator to provide an additional engineering certification that flaring is the only option where a new gathering pipeline is installed within a certain distance of an oil well. Second, the EPA is taking comment on whether it would be appropriate to require more rigorous consideration of alternatives to flaring after a set threshold is reached (e.g., after a set time of flaring (such as 2 years) or after a set volume of gas has been flared). Third, the EPA requests comment on whether there are any provisions in existing state regulations beyond what is already included in this supplemental proposal, or other measures (such as minimum capture requirements or volumetric limits on flaring), that the EPA should consider in its BSER analysis. Finally, the EPA is also soliciting comment on whether there are specific emerging technologies that should be required to be addressed in this demonstration and listed in the rule.

Requirements when Gathering System or Other Disruption Occurs. The EPA is aware that when associated gas is typically routed to a sales line there could be situations that arise that can

cause an interruption of the ability to route the gas to the sales line. As discussed above and pointed out by commenters, this situation is usually not under the control of the owner or operator of the well. The EPA agrees that interruptions where the gathering system owner is suddenly unable to accept the associated gas from the well could also occur that impact the ability to utilize the associated gas as a fuel or for another useful purpose. The EPA has considered options for this situation for this supplemental proposal. One option considered was that this situation would constitute a deviation or violation of the standard unless the owner or operator elected to shut the well in and halt the production of the associated gas. The EPA did not select this option in this supplemental proposal. The EPA concluded that such situations could constitute a technical or safety reason that could be used to justify the use of a control device that achieves 95 percent reduction of methane and VOC emissions. Therefore, the EPA is proposing to require that if owners and operators anticipate that there may be interruptions in the ability to route the associated gas to a sales line or to use it for another beneficial purpose, they must provide a technical or safety demonstration in their annual report and install and operate a control device that achieves the required reduction during these temporary periods. It is anticipated this control device would need to be permanently installed to account for these periods when associated gas could not be routed to a sales line or used for other beneficial purposes, but the EPA is soliciting comment on whether the use of temporary controls could also serve this purpose. Further the EPA is soliciting comment on what additional requirements would be necessary to ensure a temporary control device is onsite and operational to immediately control emissions when necessary for these circumstances. Venting of the associated gas under any circumstances would represent a violation of the proposed standards, even if for a short period.

Potential Exemptions and Alternative BSER for Unique Circumstances.

Several commenters on the November 2021 proposal identified situations where it would not only be infeasible to route the associated gas to a sales line or use it for another beneficial purpose, but where it would also be infeasible to route it to a flare or other control device to achieve 95 percent reduction in methane and VOC emissions. Examples of these situations include when the

flow rate, pressure, or volume of the associated gas is insufficient to route to a sales line or to support the continuous operation of a flare or combustion device; when the composition of the gas is such that it cannot be routed to a sales line or used in some manner (e.g., 97 percent CO₂ and 3 percent methane) and it does not contain sufficient heat content to combust without the addition of unreasonable amounts of propane; wildcat wells; and delineation wells. One commenter provided detailed information about the issues with certain wells in Wyoming.¹⁷⁶ The EPA believes that these situations could warrant an exemption or an alternative standard. However, this proposed rule does not include any exemptions or allowances for these situations due to lack of specific sufficient information. Therefore, the EPA is interested in additional information on gas compositions of associated gas that would make it both unusable for a beneficial purpose and unable to be flared. The EPA is not only interested in why commenters feel these situations warrant an exemption from the associated gas standards as proposed, but also what methods are currently in use, or could be used, to minimize methane and VOC emissions in these situations.

iii. Summary of Proposed Standards

In summary, this supplemental proposal allows owners and operators four compliance options to reduce or eliminate emissions of methane and VOC from associated gas from oil wells. These options are: (1) Recover the associated gas from the separator and route the recovered gas into a gas gathering flow line or collection system to a sales line, (2) recover the associated gas from the separator and use the recovered gas as an onsite fuel source, (3) recover the associated gas from the separator and use the recovered gas for another useful purpose that a purchased fuel or raw material would serve, or (4) recover the associated gas from the separator and reinject the recovered gas into the well or inject the recovered gas into another well for enhanced oil recovery.

Associated gas cannot be routed to a flare or other combustion device unless the owner or operator demonstrates that all four options discussed above are infeasible due to technical or safety reasons, and that demonstration is approved by a certified professional engineer. Any combustion device must meet the requirements in 40 CFR

¹⁷⁶ See Document ID No. EPA-HQ-OAR-2021-0317-0955.

60.5412b and that monitoring, recordkeeping, and reporting be conducted to ensure that the combustion device is constantly achieving the required 95 percent reduction. More information on the control device monitoring and compliance provisions is provided in section IV.H of this preamble.

In each annual report, owners and operators would be required to identify each well affected facility with associated gas that was constructed, modified, or reconstructed during the reporting period. The report would specify whether the associated gas will be routed into a gas gathering flow line or collection system to a sales line, used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, reinjected into the well, or injected into another well for enhanced oil recovery. If making a demonstration that it is infeasible to utilize one of these options due to technical or safety reasons, this demonstration would also be included in the first annual report. This demonstration would clearly and comprehensively justify why all of these options are infeasible, including all emerging technologies that could represent a beneficial use of the gas. This demonstration would be required in situations where the associated gas is always routed to a control device, as well as for situations where disruptions or interruptions result in the need to route the associated gas to a control device for temporary periods.

In subsequent annual reports, owners and operators complying by routing the associated gas to a gas gathering flow line or collection system to a sales line, used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, reinjected into the well, or injected into another well for enhanced oil recovery would be required to report all instances when associated gas was vented to the atmosphere. Owners and operators complying by routing the associated gas to a control device and achieving 95 percent reduction in methane and VOC would be required to report all instances when associated gas was vented to the atmosphere. In addition, these owners and operators would be required to report any changes made at the site since the original technical infeasibility demonstration and whether the change impacted the feasibility to route the associated gas to a gas gathering flow line or collection system to a sales line, use the gas as an onsite fuel source, use the gas for another useful purpose that a purchased fuel or raw material would serve, reinject the gas into the well, or

inject the gas into another well for enhanced oil recovery. If the change did not impact this feasibility, a revised demonstration and certification would be required. If the change did impact the feasibility, the owner or operator would need to report the new method of compliance that is utilized.

Required records would include documentation of the specific type of compliance method (*i.e.*, routed into a gas gathering flow line or collection system to a sales line, used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, injected into another well for enhanced oil recovery) was used. Owners and operators would also be required to maintain records that demonstrate why the required capture and use requirements are not feasible and why the use of a control device is the only option. If the control device is only used on a temporary basis when disruptions or interruptions occur in the primary compliance method for the associated gas, the owner or operator would document the periods that the gas is routed to the control device. All records associated that demonstrate proper design and operation of the control device would also be required to be maintained (see section IV.G of this preamble). Finally, all instances where emissions are vented would be recorded, along with records of actions that were taken during these periods to minimize emissions to the atmosphere.

b. EG OOOOc

The proposed presumptive standards for associated gas from existing oil wells mirror those described above for NSPS OOOOb. The EPA did not identify any circumstances that would result in a different BSER for existing sources under the EG OOOOc.

3. Gas Well Liquids Unloading Operations

a. NSPS OOOOb

i. November 2021 Proposal

In the November 2021 proposal, the EPA proposed to add standards to reduce VOC and methane emissions from each new, modified, or reconstructed gas well that conducts a well liquids unloading operation in NSPS OOOOb. In that proposal, the EPA proposed a standard that would require owners or operators to perform well liquids unloading with zero methane or VOC emissions. In the event that it is technically infeasible or not safe to perform well liquids unloading with zero emissions, the EPA proposed to require owners and operators to establish and employ BMPs to minimize

methane and VOC emissions during well liquids unloading operations to the extent possible. Two regulatory approaches were co-proposed in the November 2021 proposal. The first approach defined the affected facility as every well that undergoes liquids unloading, while the second approach defined the affected facility as every well that undergoes liquids unloading using a method that is not designed to completely eliminate venting. Both approaches require zero emissions unless technically infeasible, and where infeasible, both approaches require minimizing venting using BMPs.

ii. Changes From November 2021 Proposal

As described in section IV.E.1, the EPA is proposing to define the “affected facility” as a single well in this supplemental proposal, instead of defining it as a well that undergoes liquids unloading. Further, the EPA is revising the “modification” definition to apply to a single well that undergoes hydraulic fracturing or refracturing. This revised definition replaces the definition proposed in the November 2021 proposal, where all well liquids unloading events would have been considered a modification.

Several commenters stated that the November 2021 proposal’s definition of modification for well liquids unloading operations was flawed in a number of respects. First, commenters asserted that not all well liquids unloading operations result in an increase in emissions to the atmosphere because some operations do not vent gas and therefore have zero emissions. We agree with commenters on this point; therefore, we are not maintaining the proposed definition that every well liquids unloading operation is a modification. Second, commenters stated that well liquids unloading operations are a part of the normal operation of the well and do not result in a physical or operational change to the well, and therefore do not meet the definition of modification in 40 CFR 60.2. The EPA agrees with the commenters that well liquids unloading operations are not physical changes to the well itself. A well liquids unloading operation does not change the shape, size, or any other physical feature of the well (*i.e.*, the hole drilled for the purpose of producing oil or natural gas).

The question of whether well liquids unloading operations constitutes an operational change to the well is more nuanced. The EPA understands that every gas well will eventually need to have liquids removed in order to improve or maintain production. While

the definition of modification in this proposal has been adjusted to reflect the information commenters have provided, the EPA has yet to reach a conclusion on whether certain types of liquids unloading events could be an operational change to a well. The EPA is therefore requesting comment on operational scenarios where a well liquids unloading event could constitute a modification. Operational scenarios that may be considered a modification regarding well liquids unloading could include: (1) The first time, in the life of the well, that well liquids unloading occurs, (2) the first time, after fracturing or refracturing a well, that well liquids unloading occurs, (3) a change in the type or method of well liquids unloading, or (4) ongoing liquids unloading as part of a regular operational schedule. The EPA is requesting specific comment on whether these operational scenarios, or any additional ones, may or may not constitute a modification.

iii. Summary of Proposed Requirements

In this supplemental proposal, the EPA has provided regulatory text similar to the November 2021 co-proposed option 1, where all gas well liquids unloading operations would be subject to the regulatory requirements. The EPA is proposing the same standard of performance as discussed in the November 2021 proposal: perform well liquids unloading with zero methane or VOC emissions. The BSER is to employ techniques or technologies that eliminate methane and VOC emissions. Where it is technically infeasible or not safe to meet the zero emissions standard, employ BMPs to minimize methane and VOC emissions during well liquids unloading operations to the maximum extent possible. While we received multiple comments recommending regulating only well liquids unloading events that result in vented emissions, we are not including proposed regulatory text for the co-proposed option 2. Should the EPA decide to finalize the standards as stated in the November 2021 co-proposed option 2, the regulatory text specific to BMPs would remain relevant and is already provided in this supplemental proposal. As stated above, there are malfunctions that can result in vented emissions from well liquids unloading operations that would otherwise meet the zero emissions standard. Further, since each well liquids unloading operation is conducted based on the site-specific circumstances at the time the operation is planned, the EPA is concerned that a well might fluctuate between falling within and out of the

scope of the standards if the standards only applied to well liquids unloading operations that result in vented emissions. Therefore, for ease of implementation to the owner or operator, the EPA is proposing to apply the proposed standards to all well liquids unloading operations regardless of if the operation results in vented emissions. The EPA is, however, specifically requesting further comment and any additional information regarding co-proposed option 2, where standards only apply to wells with well liquids unloading operations that result in vented emissions.

The EPA is also proposing specific recordkeeping and reporting requirements related to well liquids unloading operations. Wells that utilize a non-venting method would have reporting and recordkeeping requirements that would include records of the number of well liquids unloading operations that occur within the reporting period and the method(s) used for each well liquids unloading operation. A summary of this information would also be required to be reported in the annual report. The EPA also recognizes that under some circumstances, venting could occur when a selected liquids unloading method that is designed to not vent to the atmosphere is not properly applied (*e.g.*, a technology malfunction or operator error). Under this proposed rule, owners and operators in this situation would be required to record and report these instances, as well as document and report the length of venting and what actions were taken to minimize venting to the maximum extent possible.

Additionally, for wells that utilize methods that vent to the atmosphere, the proposed rule would require: (1) Documentation explaining why it is infeasible to utilize a non-venting method due to technical, safety, or economic reasons; (2) development of BMPs that ensure that emissions during liquids unloading are minimized; (3) employment of the BMPs during each well liquids unloading operation and maintenance of records demonstrating that the BMPs were followed; (4) reporting in the annual report both the number of well liquids unloading operations and any instances where the well liquids unloading operations did not follow the BMPs.

b. EG OOOOc

Since the November 2021 proposal considered all well liquids unloading events to be a modification, the EPA did not propose a designated facility definition or presumptive standards for

well liquids unloading in the EG OOOOc. With the revisions to the affected facility definition and what activities constitute a modification, the EPA is now proposing to define a designated facility as a single well, like in the revised proposal for NSPS OOOOb. Further, the EPA is proposing presumptive standards for existing wells that conduct well liquids unloading operations in EG OOOOc that are the same as the standards proposed in NSPS OOOOb. Because the proposed standards provide flexibility for owners and operators to make site-specific decisions about what well liquids unloading operations to employ, the EPA did not identify any circumstances that would result in a different BSER for existing sources under EG OOOOc.

4. Well Completions

a. NSPS OOOOb

The EPA proposed to retain the requirements found in NSPS OOOO and NSPS OOOOa for reducing methane and VOC emissions through reduced emission completion (REC) and completion combustion in the November 2021 proposal. These standards would apply to well completions of hydraulically fractured or refractured oil and natural gas wells. The EPA is not proposing changes to the standards in this supplemental proposal, and the proposed regulatory text at 40 CFR 60.5375b reflects the standards of performance as proposed in the November 2021 proposal.

The proposed regulatory text included in this supplemental proposal is similar to the regulatory text found in 40 CFR 60.5375a for NSPS OOOOa. While the regulatory text is similar, the EPA has been made aware of potential confusion related to the well completion requirements and well completion recordkeeping requirements for wildcat wells, delineation wells, and low-pressure wells. Therefore, the proposed regulatory text for NSPS OOOOb includes language to clarify these particular standards for new, modified, and reconstructed sources moving forward. First, the EPA is proposing regulatory text at 40 CFR 60.5375b(f) to clearly state the requirement to route emissions from wildcat well, delineation well, and low-pressure well completions to a completion combustion device in any instance (unless combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways). The EPA is aware from implementation of NSPS OOOOa that owners and operators are unclear if they can choose to comply with 40 CFR 60.5375a(f)(3)(ii) and make

a claim of technical infeasibility for the separator to function, which then precludes the requirement to route recovered emissions to a completion combustion device. This was not the EPA's intent in NSPS OOOOa and for this reason, we are proposing to clearly specify at 40 CFR 60.5375b(f) that an alternative to route to a separator (instead of routing all flowback to a completion combustion device) is available only when the owner or operator is able to operate a separator and has the separator onsite (or otherwise available for use) and ready for use to comply with the alternative during the entirety of the flowback period.

Second, the EPA is proposing to eliminate recordkeeping requirements which are not necessary for wildcat wells, delineation wells, and low-pressure wells that had previously been included in NSPS OOOOa. Specifically, the EPA is proposing to not require records for "beneficial" use of recovered gas (*i.e.*, routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve) nor records of "specific reasons for venting in lieu of capture." These records are not required for wildcat wells, delineation wells, and low-pressure wells because the well completion standards at 40 CFR 60.5375b(f) require that all flowback, or gas recovered from flowback through the operation of a separator, be routed to a completion combustion device (*i.e.*, there will not be an instance, when complying with 40 CFR 60.5375b(f), that beneficial use of recovered gas will occur).

G. Centrifugal Compressors

As discussed in section XII.F of the November 2021 proposal preamble (86 FR 63220; November 15, 2021), centrifugal compressors are used throughout the natural gas industry to move natural gas along the pipeline. These compressors are a significant source of methane and VOC emissions. Centrifugal compressors are powered by turbines, which utilize a small portion of the natural gas being compressed to fuel the turbine. As an alternative to natural gas-fueled turbines, some centrifugal compressors use an electric motor.

Centrifugal compressors require seals around the rotating shaft to minimize gas leakage from the point at which the shaft exits the compressor casing. There are two types of seal systems: wet seal systems and mechanical dry seal systems.

Wet seal systems use oil, which is circulated under high pressure between three or more rings around the compressor shaft, forming a barrier to minimize compressed gas leakage. Very little gas escapes through the oil barrier, but considerable gas is absorbed by the oil. The amount of gas absorbed and entrained by the oil barrier is affected by the operating pressure of the gas being handled; higher operating pressures result in higher absorption of gas into the oil. Seal oil is purged of the absorbed and entrained gas (using heaters, flash tanks and degassing techniques) and recirculated to the seal area for reuse. Gas that is purged from the seal oil is commonly vented to the atmosphere.

Dry seal systems do not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. Emissions occur from dry seals around the compressor shaft vent.

1. NSPS OOOOb

a. November 2021 Proposal

i. Affected Facility

The November 2021 proposal defined the centrifugal compressor affected facility as a single centrifugal compressor using wet seals (including centrifugal compressors using wet seals located at centralized production facilities). The November 2021 proposal excluded centrifugal compressors using wet seals located at a standalone well site from the affected facility definition under NSPS OOOOb.

ii. Summary of Proposed BSER Analysis

November 2021 Proposal BSER Analysis. The BSER analysis methodology presented in the November 2021 proposal (86 FR 63221; November 15, 2021) was consistent with what was used to support the 2011 NSPS OOOO and 2016 NSPS OOOOa BSER analyses. The EPA conducted emissions reduction cost effectiveness analyses for various control options using both the single pollutant and multipollutant approaches.¹⁷⁷

The EPA used emissions factors for uncontrolled methane emissions from wet seals in the November 2021 proposal analysis that were based on the baseline uncontrolled methane emissions factors used for the 2016 NSPS OOOOa analysis, in addition to the capital costs for flares and associated equipment (*e.g.*, CVS) necessary to route emissions to the flare (with costs updated to 2016 dollars).

These baseline estimates of uncontrolled emissions were higher than the emissions the EPA estimated for these sources in both the 2015–2020 GHGRP subpart W and 2019 GHGI for all industry segments, with the exception of the GHGRP subpart W onshore production and gathering and boosting segments. The reduction in emissions attributed to centrifugal compressors in the 2019 GHGRP subpart W and 2019 GHGI is likely due to the increased deployment of emissions controls resulting from the 2012 NSPS OOOO and 2016 NSPS OOOOa, as well as a shift from the use of wet seals to dry seals by the industry since these rules were promulgated.

Various control options were evaluated as part of the November 2021 proposal to reduce emissions from centrifugal compressors. Such options included control techniques that limit emissions across the rotating shaft of the wet seal centrifugal compressor and techniques to capture and control emissions using a combustion device or by routing to a process. Based on cost analyses conducted, the November 2021 proposal for both the NSPS OOOOb and EG OOOOc rules required that VOC and/or methane emissions from each centrifugal compressor wet seal fluid degassing system be reduced by 95 percent by routing emissions to a control device or to a process.

The November 2021 proposal solicited specific comment on emissions from wet seal compressors, as well as information on lower-emitting wet seal compressor designs. See 86 FR 63221 (November 15, 2021). The EPA also solicited comments on dry seal compressor emissions, seeking information on whether, and to what degree, operational or malfunctioning conditions (*e.g.*, low seal gas pressure, contamination of the seal gas, lack of supply of separation gas, and mechanical failure) have the potential to impact methane and VOC emissions. The EPA further requested information on whether owners and operators of dry seal compressors currently implement standard operating procedures in order to identify and correct operational or malfunctioning conditions that have the potential to increase emissions from dry seal systems. Finally, the EPA also requested information on whether it should consider evaluating BSER and developing NSPS standards for dry seal compressors.

b. Changes to Proposal and Rationale

The EPA is proposing changes and clarifications to the November 2021 proposed standards for NSPS OOOOb. Specifically, we are proposing to: (1)

¹⁷⁷ See section III.E of this preamble and 86 FR 63154 (November 15, 2021).

Revise the affected facility definition to include all centrifugal compressors (*i.e.*, both wet seal and dry seal configurations), (2) specify that self-contained wet seal centrifugal compressors meet the NSPS OOOOb BSER requirements, and (3) set numerical emission limit requirements for dry seal and self-contained wet seal centrifugal compressors.

i. Wet Seal Centrifugal Compressors

The EPA received comments that included specific data on the November 2021 proposal related to emissions, costs, and the proposed standards/analyses for wet seal centrifugal compressors.¹⁷⁸ These commenters asserted that actual wet seal centrifugal compressor baseline emissions are significantly lower than the emissions estimates that the EPA used in the November 2021 proposal's BSER analysis and recommended that the EPA use updated emissions information reported under GHGRP subpart W. One of the commenters provided information on wet seal centrifugal compressor emissions for their sources in the transmission segment and requested the EPA consider using it in any new BSER analysis.¹⁷⁹ This commenter also opined that the proposed 95 percent reduction standard is unclear insofar as there is no indication of what value the reduction is to be measured against. This commenter stated that for seals that emit *de minimis* levels of VOC or methane, it would be impracticable to further reduce such emissions and that assuming emissions can be calculated, the proposed BSER of routing emissions to a control device or to a process would be cost prohibitive.

These same commenters also stated that the costs used by the EPA in the November 2021 proposal's BSER analyses were not representative of actual costs, and that the EPA had underestimated the costs for the control options evaluated. One of the commenters provided detailed cost information that they stated was more representative of actual costs for three combustion scenarios, the option to route to a process for control, and retrofit costs.

Finally, these same commenters suggested that the EPA consider a *de minimis* exemption, such as an exemption for limited use wet seal centrifugal compressors or the establishment of an emissions applicability threshold (referring to

California's centrifugal compressor requirements as an example)¹⁸⁰ where a wet seal compressor that has a measured flow rate less than a specified threshold would be exempt from regulatory requirements.

The EPA re-evaluated the November 2021 BSER in light of the suggestions from commenters related to emissions and costs. We used GHGRP subpart W emissions information because the GHGRP requires a multi-step data verification process, which increases the confidence in the reliability of data and resulting analyses.¹⁸¹ The methodology we used for estimating emissions from compressors is consistent with the methodology used for the November 2021 proposal. See 86 FR 63220 (November 15, 2021). The wet seal centrifugal compressor GHGRP subpart W methane uncontrolled emissions/emissions factors are based on volumetric emissions, which were converted to a mass emission rate for this analysis. The resulting baseline uncontrolled emissions per wet seal centrifugal compressor are 251 tpy methane (69.9 tpy VOC) from wet seal compressors at gathering and boosting sites, 163 tpy methane (45.4 tpy VOC) from wet seal compressors at natural gas processing plants, and 66 tpy methane (1.8 tpy VOC) from wet seal compressors at transmission and storage facilities. These baseline uncontrolled emissions per wet seal centrifugal compressor are higher than what we used in the November 2021 proposal analysis for the gathering and boosting segment (based on GHGRP subpart W emissions factor), but lower for all other segments of the industry.¹⁸²

The same control options from the analysis for the November 2021 proposal (routing to a control device and routing to a process) were evaluated with the above updates. Additionally, we evaluated a new option to address dry seal centrifugal compressor emissions, as discussed in more detail later in this section.

Routing to a control device. As discussed in the November 2021 proposal, a combustion device generally achieves 95 percent reduction of

methane and VOC when operated according to the manufacturer instructions. Therefore, for this analysis, we assumed that the entrained natural gas from the seal oil that is removed in the degassing process would be directed to a combustion device that achieves a 95 percent reduction of methane and VOC emissions. The combustion of the recovered gas creates secondary emissions of hydrocarbons (NO_x, CO₂, and CO emissions). Routing the captured gas from the centrifugal compressor wet seal degassing system to a combustion device has associated capital and operating costs. The capital and annual operating costs for the installation of a combustion device used in the updated analysis presented with this supplemental proposal are based on information obtained from commenters regarding a new high-end enclosed combustor.¹⁸³ These costs were adjusted from 2021 dollars to 2019 dollars for consistency with the other analyses in this rulemaking. The updated capital costs of \$123,559 were annualized at 7 percent based on an equipment life of 10 years. The total annualized capital costs were estimated to be \$17,592. The annual operating costs used are based, in part, on costs assumed in the 2011 NSPS OOOO TSD and 2016 NSPS OOOOa TSD,¹⁸⁴ with the costs again updated to reflect 2019 dollars. The resulting annual operating costs (including annual administrative, taxes, and insurance costs) were estimated to be \$105,472. Therefore, the updated estimated total annual costs (including annualized capital and operating costs) are \$123,063 per compressor. There are no cost savings estimated for this option because the recovered natural gas is combusted.

As a result of the analysis and cost-effectiveness shown in Table 32 below, the EPA has determined that the costs of routing the captured gas from the centrifugal compressor wet seal degassing system to a control device are reasonable for the control of methane for the gathering and boosting, processing and transmission, and storage segments using both the single and multipollutant approaches. The EPA also determined that the costs of routing the captured gas from the centrifugal compressor wet seal degassing system to a control device are reasonable for the control of VOC for the gathering and boosting and processing segments using both the single and multipollutant approaches.

¹⁸⁰ California's *Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities* rule (California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13, Section 95668(d)(4–9)).

¹⁸¹ EPA (2020) *Greenhouse Gas Reporting Program*. U.S. Environmental Protection Agency. Data reported as of August 7, 2021.

¹⁸² U.S. Environmental Protection Agency. *Supplemental Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG)*. August 2022.

¹⁷⁸ See Document ID Nos. EPA-HQ-OAR-2021-0317-0415 and EPA-HQ-OAR-2021-0317-1375.

¹⁷⁹ See Document ID No. EPA-HQ-OAR-2021-0317-1375.

¹⁸³ See Document ID No. EPA-HQ-OAR-2021-0317-1375.

¹⁸⁴ See Document ID Nos. EPA-HQ-OAR-2010-0505-0045 and EPA-HQ-OAR-2010-0505-7631.

Routing to a process. As discussed above, another option for reducing methane and VOC emissions from the compressor wet seal fluid degassing system is to route the captured emissions back to the compressor suction or fuel system or put them to another beneficial use (referred to collectively as “routing to a process”). One opportunity to meet this requirement would be to route emissions via a CVS or to any enclosed portion of a process unit (e.g., compressor or fuel gas system) where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. For purposes of this analysis, we assumed that routing methane and VOC emissions from a wet seal fluid degassing system to a process reduces methane and VOC emissions in amounts greater than or equal to the emissions that would be reduced by a combustion device (i.e., greater than or equal to 95 percent) because emissions are conveyed via a CVS to an enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process. There are no secondary impacts with the option to control emissions from centrifugal wet seals by capturing gas and routing to a process. This alternative is an existing compliance option under NSPS OOOO and NSPS OOOOa. The EPA has historically assumed that the emissions reduced by routing to a process are 95 percent or greater. Our understanding is that routing gas from centrifugal compressor wet seal fluid degassing systems to a process generally requires the use of a VRU or other treatment to obtain a gas stream composition suitable to be returned to the sales line or for use for another purpose. Unlike pneumatic controllers and pneumatic pumps, (see section IV.D.1.b.iii of this preamble for controllers and section IV.E.1.b.iii of this preamble for pumps), the need to use a VRU or other treatment to obtain a gas stream with a composition suitable to be returned to the sales line could result in the use of treatment components that may vent to the atmosphere or the need for maintenance where, for example, the VRU may need to be bypassed for short periods (resulting in venting of some emissions to the atmosphere). The EPA solicits comment on its assumption that the emissions reduced by requiring the

capture of gas and routing to a process is 95 percent or greater. The EPA also is soliciting comment on the prevalence of owners and operators complying with NSPS OOOO and NSPS OOOOa or other rules by routing emissions from the wet seal fluid degassing system to a process and the need for a VRU in order to be able to route emissions from the wet seal fluid degassing system to a process.

The capital and annual costs for routing the seal oil degassing system to a process used in the updated analysis are based on information obtained from commenters.¹⁸⁵ The updated capital costs are estimated to be \$600,636, and the annual costs were estimated to be \$85,517 (without savings), assuming a 10-year equipment life at 7 percent interest. Because the natural gas is not lost or combusted, the value of the natural gas represents a savings to owners and operators in the production (gathering and boosting) and processing segments. Savings were estimated using a natural gas price of \$3.13 per thousand cubic feet (Mcf), which resulted in annual savings of \$43,329 per year at gathering and boosting stations and \$28,164 per year at processing plants.

The updated analysis and cost effectiveness shown in Table 32 indicates that routing emissions to a process is cost effective for the control of methane emissions for all of the evaluated segments using the single pollutant approach and is also cost effective for methane using the multipollutant approach for the gathering and boosting and processing segments. Similarly, the updated analysis indicates that routing emissions to a process for the control of VOC for the gathering and boosting and processing segments is cost effective using both the single and multipollutant approaches. However, as noted in the November 2021 proposal, although capturing leaking gas and routing to a process has the advantage of both reducing emissions by at least 95 percent and capturing the natural gas (which results in natural gas savings), the EPA has received feedback that this option may not be viable in situations where downstream equipment capable of handling a low-pressure fuel source is unavailable.

Maintenance and repair activities to meet numerical emission limit. The EPA evaluated a third BSER option for this supplemental proposal not considered for the November 2021 proposal: maintenance and repair activities conducted to maintain emissions at or below 3 scfm, with annual flow rate

monitoring on the wet seal degassing vent (also referred to as the numerical emission limit). We did so based on comments indicating that a threshold monitoring option is a more practical option for low-emitting centrifugal compressors with wet seals (as compared to the proposed requirement to route to a control device or to a process). This option would require owners and operators to perform periodic flow rate monitoring, as well as preventative maintenance and repair as necessary, on the wet seal degassing vent to ensure compliance with the 3 scfm emission limit. The 3 scfm volumetric flow rate emission limit is the same monitoring limit included in California's Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.¹⁸⁶ California developed the 3 scfm emission standard because this was the equivalent to an average dry seal emission rate.¹⁸⁷ The commenters specifically noted that low emissions from centrifugal compressors equipped with wet seals are largely a function of proper maintenance and that requiring a 95 percent reduction standard or routing to a process creates an unintended result—the more careful an operator is with maintaining its wet seals, the more difficult and costly (on a cost-per-ton basis) controlling emissions in compliance with these requirements becomes.¹⁸⁸

The types of maintenance and repair actions that may be needed to maintain emissions at or below 3 scfm will vary considerably. One commenter,¹⁸⁹ a company that institutes an annual monitoring plan, indicated that the actions needed to reduce emissions or maintain a compressor such that it is low-emitting can range from correcting an identified issue immediately with minor maintenance, replacing o-rings on the filtration system, or having to rebuild the entire oil system. The costs associated with these maintenance and corrective actions vary significantly, from limited labor costs for a short repair activity to a significant capital cost of equipment and labor to repair and/or replace parts of the compressor. The EPA does not have specific costs for the range of maintenance and/or repairs

¹⁸⁶ California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13, Section 95668(d)(4)–(9).

¹⁸⁷ State of California. *Air Resources Board Public Hearing to Consider the Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. Staff Report: Initial Statement of Reasons.* pg. 100.

¹⁸⁸ See Document ID No. EPA–HQ–OAR–2021–0317–1375.

¹⁸⁹ See Document ID No. EPA–HQ–OAR–2021–0317–1375.

¹⁸⁵ See Document ID No. EPA–HQ–OAR–2021–0317–1375.

that may be necessary to maintain a flow rate at or below than 3 scfm. For the purposes of this analysis, the EPA selected an annual cost of \$25,000 to represent the average cost of performing the monitoring and the necessary compressor wet seal maintenance. While we recognize certain types of maintenance or corrective actions may result in costs higher than \$25,000 in one year, we believe that this is a conservative estimate to represent an average, annual cost. The EPA specifically solicits comments on the

types of maintenance or corrective actions that may be required to maintain an emission rate of 3 scfm or less from wet seal degassing, along with representative costs.

To estimate the cost effectiveness of this option, the EPA used the same updated GHGRP subpart W “uncontrolled” emissions discussed above for each centrifugal compressor with wet seals to represent baseline emissions. The “after control” emissions levels were calculated based on 3 scfm volumetric flow for 8,760 hours per year and the representative

composition of the gas in the different segments. This calculation assumes that the emissions are, on average, 3 scfm for the entire year. This represents a conservative estimate, as one commenter¹⁹⁰ indicated that the implementation of a similar program resulted in average measured emissions of less than 0.5 scfm for compressors with wet seals. Table 31 shows the baseline emissions, the emissions after implementation of the numerical emission limit, and the emission reductions for wet seal compressors.

TABLE 31—METHANE BASELINE EMISSIONS AND REDUCTIONS AFTER IMPLEMENTATION OF THE NUMERICAL EMISSION LIMIT (REQUIREMENT TO MAINTAIN FLOW RATE AT OR BELOW 3 SCFM) OPTION—WET SEAL COMPRESSORS

Segment	Methane emissions (tpy)/compressor		Methane emission reduction (tpy)
	Baseline ^a	After implementation	
Gathering and Boosting	251	27	224
Processing	163	27	136
Transmission and Storage	66	30	35

^a From GHGRP subpart W (Reporting Years 2015 to 2020—Average).

^b Calculated assuming total gas emissions are 3 scfm for 8,760 hours.

As noted above, we assumed annual maintenance, monitoring, and corrective action costs of \$25,000 (without savings). Because the natural gas is not lost or combusted, the value of that natural gas represents a savings to owners and operators in the production (gathering and boosting) and processing segments. Savings were estimated using the emission reductions noted above and a natural gas price of \$3.13 per Mcf, which resulted in annual savings of \$33,719 per year at gathering and boosting stations and \$20,486 per year at processing plants.

As a result of the wet seal centrifugal compressor analysis and cost effectiveness shown in Table 32, the EPA has determined that the costs of

implementing a numerical emission limit are reasonable for the control of methane for the gathering and boosting, processing, and transmission and storage segments using both the single and multipollutant approaches. The EPA has also determined that the costs of implementation of a numerical emission limit is reasonable for the control of VOC for the gathering and boosting and processing segments, using both the single and multipollutant approaches.

The estimated cost effectiveness values that would be associated with: (1) Capturing and routing emissions to a combustion device, (2) capturing and routing emissions to a process, and (3) conducting maintenance and repair

activities to meet a numerical emission limit (3 scfm) (referred to as the “numerical limit of 3 scfm”) for compressors with wet seals are provided in Table 32. In addition to the cost effectiveness values, Table 32 provides a conclusion regarding whether the estimated cost effectiveness value is within the range that the EPA has typically considered to be reasonable. The “overall” reasonableness determination is classified as “Y” if the cost effectiveness of either methane or VOC is within the range that the EPA considers reasonable for that pollutant, or “N” if both the methane and VOC cost effectiveness values are beyond the range that the EPA considers reasonable on a multipollutant basis.

TABLE 32—SUMMARY OF WET SEAL CENTRIFUGAL COMPRESSOR COST EFFECTIVENESS BY REGULATORY OPTION AND INDUSTRY SEGMENT

Segment/regulatory option	Cost effectiveness (\$/ton) ^a —reasonable?				Overall ^a
	Single pollutant		Multipollutant		
	Methane	VOC	Methane	VOC	
Gathering and Boosting:					
Regulatory Option One—Route Emissions to Combustion Device	\$515–Y	\$1,853–Y	\$258–Y	\$927–Y	Y
Regulatory Option Two—Route Emissions to the Process	879–Y	3,163–Y	440–Y	1,582–Y	Y
Regulatory Option Three—Numerical Limit of 3 scfm	111–Y	401–Y	56–Y	201–Y	Y
Processing:					

¹⁹⁰ See Document ID No. EPA–HQ–OAR–2021–0317–1375.

TABLE 32—SUMMARY OF WET SEAL CENTRIFUGAL COMPRESSOR COST EFFECTIVENESS BY REGULATORY OPTION AND INDUSTRY SEGMENT—Continued

Segment/regulatory option	Cost effectiveness (\$/ton) ^a —reasonable?				Overall ^a
	Single pollutant		Multipollutant		
	Methane	VOC	Methane	VOC	
Regulatory Option One—Route Emissions to Combustion Device	793–Y	2,851–Y	396–Y	1,425–Y	Y
Regulatory Option Two—Route Emissions to the Process	1,353–Y	4,866–Y	676–Y	2,433–Y	Y
Regulatory Option Three—Numerical Limit of 3 scfm Transmission and Storage:	183–Y	660–Y	92–Y	330–Y	Y
Regulatory Option One—Route Emissions to Combustion Device	1,973–Y	71,240–N	987–Y	35,620–N	Y
Regulatory Option Two—Route Emissions to the Process	3,369–N	121,607–N	1,684–Y	60,804–N	Y
Regulatory Option Three—Numerical Limit of 3 scfm	711–Y	25,650–N	355–Y	12,825–N	Y

^aFor the gathering and boosting and processing segments, the owners and operators realize the savings for the natural gas that is not emitted and lost. The cost effectiveness values shown do not consider these savings. Note that the consideration of savings does not impact whether the cost effectiveness of any of these options falls within the ranges considered reasonable by the EPA.

^bFor overall cost effectiveness to be considered reasonable, either the cost effectiveness of methane or VOC on a single pollutant basis must be within the ranges considered reasonable by the EPA, or the cost effectiveness of both methane and VOC on a multipollutant basis must be within the ranges considered reasonable by the EPA.

Summary of Control Options Evaluated. In summary, the EPA evaluated three options for wet-seal centrifugal compressors: (1) Route emissions to a control device, (2) route emissions to a process, and (3) conduct maintenance and repair to maintain emissions at or below 3 scfm. The EPA's relevant analyses found that, for all segments, the costs in relation to the emission reductions were reasonable for all three options. However, the options to route captured gas to a control device or to a process achieve greater emission reductions than conducting maintenance and repair to maintain 3 scfm. For example, for the gathering and boosting segment, we estimated that the emissions reduced under the 3 scfm numerical limit option for a representative centrifugal compressor to be 89 percent, which is less than the routing to a control or process options, which achieve 95 percent.¹⁹¹ Therefore, the EPA finds that the standard of performance for each centrifugal compressor using a wet seal is 95 percent reduction of methane and VOC emissions based on a BSER of capturing and routing emissions from the wet seal degassing system to a combustion device for new sources in the gathering and boosting, processing, and transmission and storage segments. These reductions can also be achieved by routing emissions from the wet seal degassing system to a process.

Therefore, as a compliance alternative, the EPA proposes to allow owners and operators to meet the 95 percent standard of performance by routing emissions from the wet seal degassing system to a process. The EPA notes that if an owner or operator chooses to route to a process to meet the 95 percent level of control, there are no secondary impacts. If an owner or operator chooses to route to a combustion device to meet the 95 percent level of control, the combustion of the recovered gas creates secondary emissions of hydrocarbons (NO_x, CO₂, and CO emissions).

As discussed in section III.D of this preamble, NSPS KKK includes standards for controlling VOC emissions from centrifugal compressors with wet seals at natural gas processing plants. The standards provide several options for compliance, including: (1) Operating the centrifugal compressor with the barrier fluid at a pressure greater than the compressor stuffing box pressure; (2) equipping the centrifugal compressor with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a CVS to a control device that reduces VOC emissions by 95 percent or more; or (3) equipping the centrifugal compressor with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere. NSPS KKK exempts compressors from these requirements if the compressor is either equipped with a CVS to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that reduces VOC emissions by 95 percent,

or if the compressor is designated for no detectable emissions.

For NSPS OOOOb, we are proposing that emissions from each centrifugal compressor wet seal fluid degassing system require routing to a control device that achieves a 95 percent reduction of VOC and methane emissions, or by routing the emissions to a process that achieves 95 percent reduction of VOC and methane emissions. Proposed NSPS OOOOb is equivalent to one of the three options available under NSPS KKK.

Owners and operators of wet seal centrifugal compressors have been complying with NSPS KKK since 1984. The EPA is requesting comments on whether it would provide more regulatory consistency for owners, operators, and implementing agencies if NSPS OOOOb were to incorporate all compliance options provided in NSPS KKK for wet seal centrifugal compressors at natural gas processing plants, as opposed to only proposing the compliance option of routing to a control or process proposed in this supplemental proposal.

ii. Lower-Emitting/Self-Contained Wet Seal Compressor Designs

The November 2021 proposal solicited comment and information on lower-emitting wet seal compressor designs. Commenters¹⁹² reported that the process for wet seal degassing varies throughout the industry, and some manufacturers have a configuration that is essentially a closed process that ports the degassing emissions into the natural

¹⁹¹ U.S. Environmental Protection Agency. *Supplemental Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG)*. Supporting Spreadsheets. August 2022.

¹⁹² See Document ID No. EPA-HQ-OAR-2021-0317-0415.

gas line at the compressor suction. According to one industry commenter that employs this type of wet seal centrifugal compressor, this configuration typically includes a primary chamber where initial degassing occurs (and is recovered), and chamber(s) with air sparging to release and recover residual gas volumes entrained in the oil. Rather than venting all of the de-gassing volumes, the emissions are routed back to suction directly from the degassing/sparging chambers; the oil is ultimately recycled to the lube oil tank where any small amount of residual gas is released through a vent. One commenter stated that field evaluation is not always feasible for this closed system configuration but reported that testing and modeling demonstrates that the residual natural gas volume vented is very small (much less than 1 percent of the total degassed natural gas volume). Another commenter requested that the EPA clarify that certain existing closed-loop wet seal systems be exempted from any regulatory proposal, or at a minimum, that such systems should be considered in compliance with the BSER currently applicable to wet seals.¹⁹³

Based on information indicating that closed-loop (self-contained) systems are inherently low-emitting, the EPA is proposing that these and similarly designed, self-contained wet seal centrifugal compressors represent/meet BSER (consistent with the routing to a process or control option). The EPA is proposing a definition for a “self-contained wet seal compressor” as a “wet seal 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).” The de-gas emissions are routed back to suction directly from the degassing/sparging chambers, and the oil is ultimately recycled to the lube oil tank where any small amount of residual gas is released through a vent. While the EPA recognizes the low emissions associated with these self-contained wet seal centrifugal compressors, we also recognize that there could be increased emissions due to leaks or malfunctions. Therefore, the proposed rule includes the requirement that owners or operators of self-contained wet seal centrifugal compressors must comply

with the 3 scfm numerical emission standard described below for centrifugal compressors with dry seals. As indicated above, the intent of requiring compliance with the 3 scfm numerical standard is to ensure that self-contained wet seal compressors are operating properly (without leaks or malfunctions) since EPA understands that these compressors emit trivial amounts (*i.e.*, achieve greater than 99 percent control) when properly operated. The EPA recognizes that where there is venting of any emissions from these compressors, emissions would more than likely be nondetectable for leaks, or would be at a rate lower than 3 scfm. The EPA solicits comment on, and support for, whether a lower numerical limit is needed to demonstrate proper operation of self-contained wet seal centrifugal compressors and/or equivalency to the BSER. The EPA also solicits comment on the feasibility of measuring the flow rate of self-contained wet seal centrifugal compressors at a rate lower than 3 scfm.

In addition to wet seal compressor systems that are self-contained, one commenter¹⁹⁴ reported information on another wet seal compressor that was inherently low-emitting. The commenter stated that it has facilities that use mechanical wet seals that generally have zero emissions. They explained that the metal (tungsten carbide) is seated against carbide, with oil pressing against the outside of the actual seal. They noted that because the oil is not in contact with the natural gas for these mechanical seals, these wet seals generally have zero degassing emissions. The commenter requested that the EPA exclude compressors utilizing mechanical wet seals from the wet seal compressor requirements otherwise applicable to wet seal compressors. The EPA is continuing to evaluate mechanical wet seal designs and the comments it has already received on the issue, and is soliciting additional information on these and other wet seal compressor designs (with supporting emissions information) that are inherently low-emitting under operating conditions.

iii. Dry Seal Compressors

The EPA solicited comments on dry seal compressor emissions and whether, and to what degree, operational or malfunctioning conditions (*e.g.*, low

seal gas pressure, contamination of the seal gas, lack of supply of separation gas, mechanical failure) have the potential to impact methane and VOC emissions. The EPA further requested information on whether owners and operators implement standard operating procedures to identify and correct operational or malfunctioning conditions that have the potential to increase emissions from dry seal systems, and whether EPA should consider evaluating BSER and developing NSPS standards for dry seal compressors.

As the EPA has heard previously, the commenters noted that some dry seal compressors have higher emissions than compressors with wet seals. Based on input from a couple of commenters, we estimated the cost effectiveness of conducting preventative maintenance and repair, as needed, to maintain the volumetric flow rate from each centrifugal compressor that uses a dry seal at or below 3 scfm (as done for those with wet seals). The 3 scfm volumetric flow rate emission limit is the same monitoring limit included in California’s Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities for wet seal compressors.¹⁹⁵ California developed the 3 scfm emission standard because this was the equivalent to an average dry seal emission rate.¹⁹⁶ The EPA did not evaluate any other control options for compressors with dry seals because they are inherently low-emitting; increased emissions are generally the result of either unforeseen upset conditions or poor maintenance.

To estimate the cost effectiveness of this option, we used the 2019 GHGI “uncontrolled” emissions for dry seal compressors as the baseline.¹⁹⁷ The “after control” emissions levels were calculated based on a threshold of 3 scfm volumetric flow for 8,760 hours per year and the representative composition of the gas in the different segments. This calculation assumes that the emissions are, on average, 3 scfm for the entire year. Table 33 shows the baseline emissions, the emissions after implementation of the numerical emission limit, and the emission reductions for dry seal compressors. The 3 scfm volumetric flow emission limit is the same as described above for wet seal centrifugal compressors.

¹⁹³ See Document ID No. EPA-HQ-OAR-2021-0317-1375.

¹⁹⁴ See Document ID No. EPA-HQ-OAR-2021-0317-0415.

¹⁹⁵ California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13, Section 95668(d)(4-9).

¹⁹⁶ State of California. Air Resources Board Public Hearing to Consider the Proposed Regulation for

Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. Staff Report: Initial Statement of Reasons. pg. 100.

¹⁹⁷ GHGI-Dry Seals.

TABLE 33—METHANE BASELINE EMISSIONS AND REDUCTIONS AFTER IMPLEMENTATION OF THE ANNUAL EMISSION LIMIT (REQUIREMENT TO MAINTAIN FLOW RATE AT OR BELOW 3 SCFM) OPTION—DRY SEAL COMPRESSORS

Segment	Methane emissions (tpy)		Methane emission reduction (tpy)
	Baseline ^a	After implementation	
Gathering and Boosting	36	6	30
Processing	28	1	27
Transmission and Storage	44	6	38

^aBased on GHGI. Emissions from dry-seal compressors are not estimated for gathering and boosting in the GHGI. The baseline emissions were calculated from the transmission and storage emissions (adjusted for the difference in gas composition).

As discussed above for wet seal centrifugal compressors, there is a wide range in the types of repairs needed (and associated costs) for dry seal compressors. Given the lack of specific information on these repairs and costs, we assumed the annual costs to comply with this option to be \$15,000 (without savings). This assumption is lower than the comparable assumption for wet seals because annual operating and maintenance costs for compressors with dry seals are lower than for compressors with wet seals. The EPA specifically solicits comments on the types of maintenance and corrective actions that may be required to maintain an emissions rate of 3 scfm or less from

centrifugal compressors with dry seals, along with representative costs.

Because natural gas emissions from a centrifugal compressor with dry seals would be reduced by maintaining the emission rate at or below 3 scfm, the value of the retained natural gas that would have otherwise been emitted represents a savings to owners and operators in the production (gathering and boosting) and processing segments. Savings were estimated using the emission reductions noted above and a natural gas price of \$3.13 per Mcf, which resulted in annual savings of \$2,425 per year at gathering and boosting stations and \$1,170 per year at processing plants.

The estimated cost effectiveness values that would be associated with

conducting maintenance and repair activities to meet a numerical emission limit of 3 scfm for dry seal compressors are provided in Table 34. In addition to the cost effectiveness values, Table 34 provides a conclusion regarding whether the estimated cost effectiveness value is within the range that the EPA has typically considered to be reasonable. The “overall” reasonableness determination is classified as “Y” if the cost effectiveness of either methane or VOC is within the range that the EPA considers reasonable for that pollutant, or “N” if both the methane and VOC cost effectiveness values are beyond the range the EPA considers reasonable on a multipollutant basis.

TABLE 34—SUMMARY OF DRY SEAL CENTRIFUGAL COMPRESSOR COST EFFECTIVENESS BY INDUSTRY SEGMENT—NUMERICAL LIMIT OF 3 SCFM

Segment	Cost effectiveness (\$/ton) ^a —reasonable?				Overall ^b
	Single pollutant		Multipollutant		
	Methane	VOC	Methane	VOC	
Gathering and Boosting	930–Y	3,346–Y	\$465–Y	\$1,673–Y	Y
Processing	1,927–Y	6,933–N	964–Y	3,467–Y	Y
Transmission and Storage	831–Y	29,997–N	415–Y	14,999–N	Y

^aFor the gathering and boosting and processing segments, the owners and operators realize the savings for the natural gas that is not emitted and lost. The cost effectiveness values shown do not consider these savings. Note that the consideration of savings does not impact whether the cost effectiveness of any of these options falls within the ranges considered reasonable by the EPA.

^bFor overall cost effectiveness to be considered reasonable, either the cost effectiveness of methane or VOC on a single pollutant basis must be within the ranges considered reasonable by the EPA, or the cost effectiveness of both methane and VOC on a multipollutant basis must be within the ranges considered reasonable by the EPA.

Based on the consideration of the costs in relation to the emission reductions for methane shown in Table 34, the costs to implement the option to conduct preventative repair and maintenance so that each centrifugal compressor with a dry seal maintains a volumetric flow rate at or below 3 scfm is reasonable for all segments under both the single pollutant and multipollutant approaches. Based on the consideration of the costs in relation to the emission reductions for VOC, the costs of this option are reasonable for the gathering and boosting segment

under both the single pollutant and multipollutant approaches. For the processing segment, the costs for reducing VOC emissions are reasonable under the multipollutant approach, but not the single pollutant approach. Costs for reducing VOC emissions would not be reasonable for implementing this approach for the transmission and storage segment. Given that the costs of conducting preventative repair and maintenance activities in order to maintain the volumetric flow rate from each centrifugal compressor with a dry seal at or below 3 scfm are reasonable,

the EPA is proposing this option as BSER for compressors with dry seals.

c. Summary of 2022 Proposal

i. Affected Facility

Based on changes made and discussed in section IV.G.1.b of this preamble, the EPA is proposing to redefine the affected facility to include dry seal centrifugal compressors in addition to wet seal centrifugal compressors. Therefore, a centrifugal compressor affected facility would be defined as a single centrifugal compressor. Further, the EPA is maintaining the proposed

specifications from the November 2021 proposal as applicable to centrifugal compressors located at well sites and centralized production facilities. Specifically, centrifugal compressors located at centralized production facilities would be considered affected facilities, while those located at well sites would not be affected facilities under NSPS OOOOb.

ii. Requirements

Wet Seal Centrifugal Compressors. The EPA is proposing that owners or operators of centrifugal compressor affected facilities with wet seals must comply with the GHG and VOC standards by reducing methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent. As an alternative to routing the CVS to a control device, an owner or operator may also route the CVS to a process or utilize a self-contained wet seal centrifugal compressor. If an owner or operator chooses to comply with this requirement either by using a control device to reduce emissions or by routing to a process to reduce emissions, an owner or operator must equip the wet seal fluid degassing system with a cover and the cover must be connected through a CVS meeting specified requirements (40 CFR 60.5411b(a) through (c)), such as design and operation with no identifiable emissions, as described in section IV.K of this preamble. If an owner or operator uses a self-contained wet seal centrifugal compressor, an owner or operator must ensure a volumetric flow rate at or below 3 scfm. In addition to the flow rate monitoring required every 8,760 hours, additional preventative or corrective measures may be required to ensure compliance.

Dry Seal Centrifugal Compressors. The EPA is proposing that the standard of performance for centrifugal compressor dry seals is 3 scfm. The proposed BSER is for an owner or operator to conduct preventative maintenance and repair of their centrifugal compressors that use dry seals, as needed, to maintain the volumetric flow rate from each centrifugal compressor that uses a dry seal at or below 3 scfm. Owners and operators of centrifugal compressors with dry seals must conduct volumetric emissions measurements from each centrifugal compressor dry seal vent on or before 8,760 hours of operation or previous measurement and must use specified methods (similar to the flow rate monitoring requirements specified under the GHGRP subpart W) in doing so. Owners or operators must ensure

that the volumetric emission measurements (in operating mode or in stand-by-pressurized-mode) from each centrifugal compressor dry seal vent are less than or equal to a flow rate 3 scfm (in operating or standby pressurized mode) or a manifolded dry seal compressor flow rate less than or equal to the number of compressors multiplied by 3 scfm (in operating or standby pressurized mode). As discussed in section IV.I the EPA is proposing the use of volumetric flow rate which meet the requirements of Method 2D (40 CFR part 60, appendix A) for testing emissions from reciprocating compressor rod packing and the use of a high-volume sampler to measure the emissions from either the reciprocating compressor rod packing or centrifugal compressor seal vent (dry seals for NSPS OOOOb and all centrifugal compressor wet and dry seals for EG OOOOc). For the high-volume sampler, instead of relying on manufacturer defined procedures required in GHGRP Subpart W, the EPA is proposing a defined set of procedures and performance objectives to ensure consistent application of these samplers. In an effort to allow for additional innovation for these types of measurements, the EPA is also proposing to allow other methods, subject to Administrator approval, that have been validated according to Method 301 (40 CFR part 63, appendix A). Preventative maintenance or other corrective actions may be necessary (in addition to the monitoring every 8,760 hours of operation) in order for owners or operators to ensure compliance at all times (consistent with the general duty clause 40 CFR 60.5470b(b)) with the required flow rate of 3 scfm or less.

Recordkeeping and Reporting Requirements. Specific recordkeeping and reporting requirements would also apply for each wet seal centrifugal compressor affected facility. Specifically, records and annual reporting that identifies each centrifugal compressor using a wet seal system that was constructed, modified, or reconstructed during the reporting period would be required. In instances where a deviation from the standard occurred during the reporting period and recorded, an owner or operator would be required to provide information on the date and time the deviation began, the duration of the deviation, and a description of the deviation.

For centrifugal compressors where compliance is achieved by using a control device to reduce emissions, the following information would be required in the annual report: dates of

the cover and CVS inspections, whether defects or leaks are identified, and the date of repair or the date of anticipated repair if repair is delayed. Where bypass requirements apply, reporting of the date and time of each bypass alarm or each instance the key is checked out would be required.

If complying with the centrifugal compressor requirements for wet seal fluid degassing system by reducing VOC and methane emissions by 95 percent using a control device tested by the device manufacturer, the annual report must include: the identification of the compressor with the control device and the make, model, and date of purchase of the control device. An owner or operator would also be required to record and report the following: (1) Each instance where there is an inlet gas flow rate exceedance, (2) each instance where there is no indication of a pilot flame, and (3) each instance where there was a visible emissions exceedance. The annual report would be required to include the date and time the deviation began, the duration of the deviation, and a description of the deviation. Finally, for each visible emissions test following return to operation from a maintenance or repair activity, the annual report would be required to include the date of the visible emissions test, the length of the test, and the amount of time visible emissions were present.

If complying with the centrifugal compressor requirements for a wet seal fluid degassing system by reducing VOC and methane emissions by 95 percent by using a control device not tested by the device manufacturer, the following information must be included in the annual report: identification of the control device not tested by the device manufacturer, the identification of the compressor with the tested control device, the date the performance test was conducted, the pollutant(s) tested, and the performance test report conducted to demonstrate that the control device is achieving, at a minimum, the required 95 percent reduction.

For each dry seal centrifugal compressor affected facility and self-contained wet seal centrifugal compressor affected facility, owners and operators would be required to track and report the cumulative number of hours of operation since startup since the previous screening/volumetric emissions measurement in order to demonstrate compliance with their volumetric emissions measurements. Additionally, a description of the method used and the results of the volumetric emissions measurement or

emissions screening, as applicable, would be required in the annual report.

2. EG OOOOc

a. Summary of 2021 Proposal

The summary of the November 2021 proposal for EG OOOOc is consistent with what was proposed for NSPS OOOOb (see section IV.G.1.a of this preamble).

b. Changes to Proposal and Rationale

The EPA is proposing changes and specific clarifications to the November 2021 proposal presumptive standards for the EG OOOOc. Specifically, we are proposing to: (1) Revise the designated facility definition to include all centrifugal compressors, (2) include a numerical emission limit requirements for dry and wet seal compressors, and (3) allow owners and operators the option to comply with EG OOOOc by reducing methane emissions by 95 percent by either routing to a control device or to a process. The basis for these changes is presented below.

Wet Seal Centrifugal Compressors. Industry commenters expressed particular concern about having to retrofit existing wet seal centrifugal compressors to accommodate the November 2021 proposal that would have required owners and operators to reduce methane emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent or greater. One commenter¹⁹⁸ stated that the November 2021 proposal for wet seal centrifugal compressors would require installation of an enclosed combustion device or a process flare in nearly every case for their facilities. The commenter noted that, while theoretically an enclosed combustion device could be installed to control the minimal emissions on an individual wet seal compressor, a combustion device cannot be located just anywhere, especially not in close proximity to a transmission compressor station. The commenter noted that a combustion device must be strategically located away from combustible materials, which typically requires a significant footprint, aboveground piping (above roadways), and in an elevated location. In order to install such a device, they stated that they would likely have to apply for and receive state and local permit modifications, which are not certain to be approved in each case. The commenter also stated that routing to a control device could present safety concerns. For example, they note that attempts to capture a low-pressure

natural gas vent stream, such as that of the wet seal, could result in inducing air into the gas stream, potentially creating a combustible mixture. The commenter reports that one manufacturer has previously “caution[ed] the use of flaring with gas seal vented emissions due to risk of the potential explosive hazard and back-flashing.”¹⁹⁹ The commenter reports that it is “[their] view (concurrent with many users of our equipment) [that] flaring of compressor seal emissions can introduce inherently dangerous conditions with the potential for back-flashing and serious risk of explosion. Solar therefore discourages flaring for this reason although some customers have successfully implemented it.”

With respect to the routing to process option, the same commenter notes that, while theoretically feasible, a low flow gas stream (like their facilities’ gas streams) cannot be safely or technically re-introduced back into their processes without significant, resource-intensive, attention to that minor emissions stream. According to the commenter, the unintended result would be that the additional equipment that would need to be installed to accomplish this routing back to process would not only be costly (discussed below) but could also result in additional emissions from other sources.

Based on these concerns, for existing wet seal centrifugal compressors, the EPA is no longer proposing that BSER is 95 percent reduction of methane emissions by routing emissions to a control device or process. Instead, based on the updated analysis presented in this supplemental proposal, the EPA is proposing that the standard of performance for existing sources is a numerical emission limit of 3 scfm; the BSER is for an owner or operator to conduct preventative maintenance and repair of their centrifugal compressors that use wet seals, as needed, to maintain the volumetric flow rate from each centrifugal compressor that uses a wet seal at or below 3 scfm. Owners or operators would be required to conduct volumetric flow rate measurements at least every 8,760 hours. As a compliance alternative, the EPA is proposing to allow owners and operators the option to reduce methane emissions by 95 percent or greater by routing emissions to a control device or to a process, which would achieve emissions reductions equal to or greater than the standard of performance of 3 scfm. The cost of application of the numerical emission limit requirement at

an existing source is the same as at a new source, and the methane cost effectiveness would be the same as discussed in the previous section for wet seal centrifugal compressors subject to NSPS OOOOb. The cost effectiveness (without natural gas savings) of complying with the numerical emission limit for methane emissions is approximately \$111 per ton of methane emissions reduced for the gathering and boosting segment, \$183 per ton of methane emissions reduced for the processing segment, and \$711 per ton of methane emissions reduced for the transmission and storage segment. Considering natural gas savings, the cost effectiveness of complying with the numerical emission limit for methane emissions is an overall net savings for the gathering and boosting segment, and \$28 per ton of methane emissions reduced for the processing segment.

As discussed in section IV.G.1.i of this preamble NSPS KKK includes standards for controlling VOC emissions from centrifugal compressors with wet seals at natural gas processing plants. The standards provide several options to comply, including: (1) Operating the centrifugal compressor with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; (2) equipping the centrifugal compressor with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a CVS to a control device that reduces VOC emissions by 95 percent or more; or (3) equipping the centrifugal compressor with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere. NSPS KKK exempts compressors from these requirements if the compressor is either equipped with a CVS to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that reduces VOC emissions by 95 percent, or if the compressor is designated for no detectable emissions.

For EG OOOOc, the proposed presumptive standard would be a numerical emission limit of 3 scfm and include an alternative compliance method of reducing methane emissions by 95 percent by routing to a control or process. The proposed presumptive standard of 3 scfm is less stringent than the regulatory compliance options under NSPS KKK for centrifugal compressor at natural gas processing plants.

Owners and operators of wet seal centrifugal compressors have been complying with NSPS KKK since 1984. The EPA is requesting comments on whether it would provide more

¹⁹⁸ See Document ID No. EPA-HQ-OAR-2021-0317-1375.

¹⁹⁹ See Document ID No. EPA-HQ-OAR-2021-0317-1375.

regulatory consistency for owners, operators, and implementing agencies if EG OOOOc were to incorporate all compliance options provided in NSPS KKK for wet seal centrifugal compressors at natural gas processing plants instead of the 3 scfm emission limitation.

Dry Seal Compressors. The application of the numerical emission limit option at an existing source is the same as at a new source because no additional equipment must be installed in order to comply with the standards. Therefore, the cost of control would also be the same (see section IV.G.1.b.i of this preamble). As a result, based on the consideration of the costs in relation to the emission reductions for methane, the costs to implement the numerical emission limit is reasonable for all segments. Given that the costs of reducing methane emissions by the implementation of the numerical emission limit are reasonable, the EPA is proposing this option as BSER for existing centrifugal compressors with dry seals.

c. Summary of 2022 Proposal

i. Designated Facility

Based on changes made and discussed under section IV.F.2.b of this preamble, the EPA is proposing to redefine the designated facility to include dry seal compressors in addition to wet seal compressors. Specifically, the designated facility is defined as a single centrifugal compressor. Further, the EPA is proposing that centrifugal compressors located at centralized production facilities would be designated facilities, while centrifugal compressors located at well sites would not be designated facilities, consistent with the November 2021 proposal.

ii. Requirements

Wet and Dry Seal Centrifugal Compressors. The EPA is proposing that owners or operators of centrifugal compressors with wet and dry seals be required to conduct volumetric emission measurements (in operating mode or in stand-by-pressurized-mode) from each centrifugal compressor dry and wet seal vent using specified methods (similar to the flow rate monitoring requirements specified under GHGRP subpart W). Owners and operators would be required to conduct volumetric emissions measurements from each centrifugal compressor wet and dry seal vent on or before 8,760 hours of operation or previous measurement.

The volumetric emissions measurement of the centrifugal

compressor wet and dry seal vent must be maintained to be less than or equal to a flow rate of 3 scfm (in operating or standby pressurized mode) or a manifolded dry and wet seal compressor flow rate less than or equal to the number of compressors multiplied by 3 scfm (in operating or standby pressurized mode). The same requirements specified in IV.G.1.c of this preamble for dry seal compressors complying with the numerical emission limit being proposed for NSPS OOOOb are being proposed for self-contained wet seal centrifugal compressors under NSPS OOOOb and for dry and wet seal centrifugal compressors complying with this option under EG OOOOc.

Compliance Alternative for Wet Seal Compressors. As a compliance alternative to maintaining a flow rate at or below 3 scfm, the EPA is proposing that an owner or operator of a centrifugal compressor equipped with wet seals can comply with EG OOOOc by reducing methane emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent, which achieves emission reductions greater than or equal to the 3 scfm proposed presumptive standard. Options to meet this emission reduction requirement include routing emissions via a CVS to a control device or to the process. This standard can also be met by an owner or operator utilizing a self-contained wet seal centrifugal compressor. The same requirements specified in IV.G.1.c for wet seal compressors complying with the requirements to reduce methane emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent are being proposed for wet seal compressors complying with this option under EG OOOOc.

H. Combustion Control Devices

1. November 2021 Proposal

The EPA proposed requiring 95 percent methane and VOC reduction for certain affected/designated facilities (*i.e.*, storage vessels, wet seal centrifugal compressors, and associated gas from oil wells when a sales line is not available) and solicited comments on several aspects of the operational efficiency of combustion control devices and methods to ensure continuous compliance with the required control efficiency. Specifically, in the November 2021 proposal, the EPA solicited comments on whether additional measures to ensure proper performance of flares would be appropriate to ensure that flares meet the current 95 percent control requirement. The EPA solicited similar

comments for enclosed combustion devices, particularly regarding creating comprehensive specifications for an operating envelope under which a make/model can achieve 98 percent reduction. The EPA also solicited comments on the practicality of requiring combustion and non-combustion control systems to meet a 98 percent reduction control requirement under operating conditions present in the oil and gas industry. Finally, the EPA solicited comment on new technologies that would provide real-time or near real-time measurement of control efficiency, particularly for flares.

2. Changes From November 2021 Proposal

The EPA received comments on most aspects of the solicitation for comments in the November 2021 proposal related to combustion control devices, ranging from opposition to requirements as specific as continuous pilots to recommendations for the use of advanced technologies to continuously monitor flare combustion efficiency. As described throughout this section, the EPA is proposing specific additional requirements in response to comments on the November 2021 proposal and clarifying other requirements that were proposed in that action.

In this supplemental proposal, the EPA is proposing requirements for various combustion control devices to develop consistent monitoring, recordkeeping, and reporting requirements, regardless of the affected/designated facility with which the control device is associated. This is different than the compliance requirements for control devices in NSPS OOOOa, which has separate requirements for control devices used on storage vessel affected facilities, than those used on centrifugal compressor affected facilities. The proposed monitoring, recordkeeping, and reporting requirements related to control devices are designed to ensure that these systems achieve the required control efficiency, and they were established using methods that limit the burden for owners and operators, while still ensuring compliance with the required control efficiency.

Flares. The EPA is proposing to include in both NSPS OOOOb and EG OOOOc more comprehensive monitoring requirements for flares as referenced to the General Provisions at 40 CFR 60.18. Specifically, the General Provisions at 40 CFR 60.18 indicate four criteria needed for good flare performance. These are: (1) Continuous pilot flame; (2) no visible emissions except for a total of 5 minutes in a 2-

hour period; (3) minimum net heating value of gas sent to the flare; and (4) maximum flare tip velocity. In NSPS OOOO and NSPS OOOOa, the compliance requirements for flares include criteria to address compliance with items 1 and 2 but do not include any requirements that would ensure compliance with items 3 and 4 for any affected facilities which reference flares as a control device option. That is, those rules, which adopt by reference the flare requirements in 40 CFR 60.18 (*i.e.*, the General Provisions to 40 CFR part 60) do not include specific requirements specifying the minimum net heating value of gas sent to the flare or the maximum flare tip velocity. One commenter on the November 2021 proposal stated that the EPA must establish continuous monitoring requirements for flares regardless of the control efficiency required.²⁰⁰ One commenter noted that the General Provisions at 40 CFR 60.18 state that the referencing subpart will specify the monitoring requirements and indicated that the EPA must specify these requirements in the new standards.²⁰¹ The EPA agrees with these commenters, especially noting that recent studies suggests that 10 percent of flares in the Permian basin are either unlit or are only burning a portion of the gas sent to the flare.²⁰² Consequently, the EPA concludes that the current operating and monitoring practices and requirements for well sites and centralized production facilities are not adequate to ensure flare control systems are operated efficiently and is therefore, proposing compliance requirements to ensure all aspects of the General Provisions at 40 CFR 60.18 are met at all times. These include requirements to ensure a pilot flame is present at all times through monitoring with a device such as a thermocouple, ultraviolet beam sensor, or infrared sensor and monitoring of NHV through use of a calorimeter, unless a demonstration has been made that the NHV of the inlet gas to the flare consistently exceeds the operating limit established in the rule. In other rulemakings, for example recent amendments to the refining²⁰³ and chemical sector²⁰⁴ rules, monitoring of

the net heating value in the combustion zone, instead of the heating value of the vent gas is required. While this is important for an assisted flare, we anticipate the oil and gas source category predominately will use unassisted flares, because air-assisted flares require electricity and not all sites will have access to electricity. The EPA finds that the provisions at 40 CFR 60.18 are sufficient for unassisted flares because the heat content of the gas at the flame is not diluted by an assist stream of gas or air. The EPA requests comment on the universe of unassisted and assisted flares in the oil and gas sector. See section IV.H.3 of this preamble for details of the proposed compliance requirements for flares.

Enclosed Combustors. The EPA is proposing the same monitoring requirements for enclosed combustion devices for all affected facilities that use such devices to meet the applicable standards. We are also proposing monitoring requirements for enclosed combustion devices (which are not tested by the manufacturer) for which the performance test does not correlate the combustion efficiency achieved by the combustion device with temperature. (*i.e.*, temperature is not well correlated with combustion efficiency). NSPS OOOO and OOOOa have separate monitoring requirements for control devices used for centrifugal compressor affected facilities than for control devices used for storage vessel affected facilities. This difference goes back to the EPA's understanding of the landscape of the oil and gas industry during the rulemaking process for NSPS OOOO and subsequent amendments through 2016 which resulted in the promulgation of NSPS OOOOa. Centralized production facilities were not identified within the EPA's emissions inventory, and the EPA found that storage vessels were mostly located at well sites which did not have other affected facilities requiring control. The EPA expected these sites to take advantage of the reduced compliance burden by using control devices tested by the manufacturer. Further, during the reconsideration of aspects of NSPS OOOO, the EPA determined that streamlined compliance options were warranted for storage vessel affected facilities, in part because of implementation issues at remote sites and the large number of storage vessel affected facilities.²⁰⁵ In this action, the EPA is proposing standards for additional affected facilities at well sites (*i.e.*, oil wells with associated gas that is

routed to a control device) and defining centralized production facilities (which include storage vessel and compressor affected facilities requiring 95 percent control). The EPA finds that the rationale used in NSPS OOOO and NSPS OOOOa supporting streamlined monitoring for storage vessels no longer holds true. Remote well sites still exist, but these sites also may be subject to standards for oil well with associated gas and the compliance burden is shared between those affected facilities to ensure emissions from both storage vessels and oil wells with associated gas are reduced by 95 percent. Further, the centralization of production activities makes moot the concern about remote wells sites for these centralized production facilities. As mentioned previously, recent studies such as the study conducted in the Permian, indicate pervasive issues with combustion sources²⁰⁶ and enforcement activities conducted by the EPA and states have uncovered issues with proper operation of enclosed combustors on storage vessels.²⁰⁷ For these reasons, the EPA is proposing to align the monitoring requirements in NSPS OOOOb and EG OOOOc to ensure that all control devices are subject to the same monitoring requirements, regardless of the affected facility being controlled.

For thermal oxidizers/enclosed combustors for which temperature is correlated with combustion efficiency and for catalytic oxidizers, the EPA is proposing to include in NSPS OOOOb and EG OOOOc the same monitoring requirements as required under NSPS OOOOa for centrifugal compressor affected facilities, and consistent with the rationale in this discussion, we are proposing to require these monitoring requirements for all enclosed combustion devices, regardless of the affected facility being controlled. Further, the EPA is proposing additional initial compliance requirements for vapor recovery devices and catalytic vapor incinerators, to ensure owners and operators have a clear roadmap for initial compliance. Similarly, the EPA is proposing additional continuous compliance requirements which specify how to determine continuous compliance with the requirements for

²⁰⁰ See Document ID Nos. EPA-HQ-OAR-2021-0317-0844 and EPA-HQ-OAR-2021-0317-1282.

²⁰¹ See Document ID No. EPA-HQ-OAR-2021-0317-1282.

²⁰² Permian Methane Analysis Project (PermianMAP) reporting the results of 4 Environmental Defense Fund (EDF) surveys of over a thousand flare stacks from February to November 2020. See <https://www.permianmap.org/flaring-emissions>.

²⁰³ See 80 FR 75266 (December 1, 2015).

²⁰⁴ See 85 FR 49132 (August 12, 2020).

²⁰⁵ See 78 FR 58438 (September 23, 2013) and 81 FR 35897 (June 3, 2016).

²⁰⁶ Permian Methane Analysis Project (PermianMAP) reporting the results of 4 Environmental Defense Fund (EDF) surveys of over a thousand flare stacks from February to November 2020. See <https://www.permianmap.org/flaring-emissions>.

²⁰⁷ "EPA Observes Emissions from Controlled Storage Vessels at Onshore Oil and Gas Production Facilities." See <https://www.epa.gov/sites/default/files/2015-09/documents/oilgascompliancealert.pdf>.

catalytic vapor incinerators, regenerative-type carbon adsorption systems, and carbon management for regenerative-type and nonregenerative-type carbon adsorption systems.

The EPA is also proposing monitoring requirements for enclosed combustion devices not tested by a manufacturer for which temperature is not well correlated with combustion efficiency. For enclosed combustors for which temperature is not well correlated with combustion efficiency, the EPA is proposing to incorporate requirements similar to those proposed for flares, as the operation of these devices is similar to the operation of a flare in that the combustibility of the gas (NHV), operation without smoking (visible emissions) and a continuous burning pilot flame are fundamental to ensuring 95 percent combustion. One commenter suggested that monitoring of the pilot flame for enclosed combustors was sufficient to provide assurance of effective emission control.²⁰⁸ However, no data were provided to support this assertion and available data and combustion theory science suggests that the net heating value of the gas being sent to the combustor is also critical to ensure proper combustion. As good combustion depends upon the fuel having a minimum amount of heat content, if the gases from the affected facility required to be controlled have low heat content at times, then auxiliary fuel may be necessary to ensure good combustion during those periods. That is, the same requirements that are needed to ensure proper performance of flares also apply to enclosed combustors. Because enclosed combustors often are associated with storage vessels which have variable emissions events depending on working, breathing, standing, or flashing losses, the EPA also is proposing that enclosed combustors monitor inlet flow rate to ensure the control device operates within the compliance envelope at which compliance with the 95 percent control efficiency was demonstrated.

Condensers and Carbon Adsorption Systems. The EPA is proposing consistent monitoring requirements for condensers and carbon adsorption systems independent of the affected facility. NSPS OOOOa has specific compliance requirements for condensers and carbon adsorption systems used to control emissions from centrifugal compressor affected facilities but less specific compliance requirements for vapor recovery devices used for storage

vessel affected facilities. In NSPS OOOOa, owners and operators are required to conduct specific parameter monitoring for condensers and carbon adsorption systems used to control emissions from centrifugal compressor affected facilities, while owners and operators are only required to conduct monthly inspections “. . . to ensure physical integrity of the control device according to the manufacturer’s instructions” for vapor recovery devices used to control storage vessel affected facilities. Monthly inspections do not ensure the condenser temperature is adequate or that the carbon beds are changed out or regenerated at a frequency to ensure the control device is achieving at least 95 percent control efficiency. Therefore, in NSPS OOOOb and EG OOOOc, the EPA is proposing that all affected and designated facilities that use condensers or carbon adsorption systems must meet the same monitoring requirements as outlined for centrifugal compressor affected facilities in NSPS OOOOa.

Manufacturer Tested Control Devices. The EPA is proposing to require the same initial requirements for manufacturer testing of control devices and ancillary monitoring requirements as required in NSPS OOOO and NSPS OOOOa. In NSPS OOOO and NSPS OOOOa, the EPA included this alternative to minimize issues associated with performance testing of certain combustion control devices in the field. The requirements were based on similar requirements in the oil and natural gas NESHAP (40 CFR part 63, subparts HH and HHH) and which had been successfully implemented for some time prior to the promulgation of NSPS OOOO and NSPS OOOOa. In the 2011 proposal of the provisions for NSPS OOOO, we stated “[w]e believe that testing units that are not configured with a distinct combustion chamber present several technical issues that are more optimally addressed through manufacturer testing, and once these units are installed at a facility, through periodic inspection and maintenance in accordance with manufacturers’ recommendations. One issue is that an extension above certain existing combustion control device enclosures will be necessary to get adequate clearance above the flame zone. Such extensions can more easily be configured by the manufacturer of the control device rather than having to modify an extension in the field to fit devices at every site. Issues related to transporting, installing and supporting the extension in the field are also eliminated through manufacturer

testing. Another concern is that the pitot tube used to measure flow can be altered by radiant heat from the flame such that gas flow rates are not accurate. This issue is best overcome by having the manufacturer select and use the pitot tube best suited to their specific unit. For these reasons, we believe the manufacturers’ test is appropriate for these control devices with ongoing performance ensured by periodic inspection and maintenance. (76 FR 52785; August 23, 2011).

Control Efficiency. As mentioned earlier in this section, the EPA requested comment on whether the EPA should require 98 percent reduction of methane and VOC emissions instead of 95 percent in the November 2021 proposal. The EPA received comments stating that flares can be designed to meet 98 percent control efficiency,²⁰⁹ but we also received comments stating that variability in gas flow, pressure, and quality would present challenges to achieving 98 percent control efficiency, especially at low production wells.²¹⁰

The EPA evaluated the costs associated with requiring 98 percent reduction of methane and VOC emissions from storage vessels in order to compare the cost-effectiveness for this option against the costs associated with requiring 95 percent reduction. While the analysis was specific for storage vessels, the conclusions drawn from this analysis are generally applicable to other affected facilities because the size range of control devices evaluated cover the range of controls used for other affected facilities. Based on this evaluation, we conclude that the additional reduction is not cost effective and would therefore not represent the BSER for affected sources requiring an emissions reduction through the use of a pollution control device. Specifically, using this example for storage vessel affected facilities, the EPA added the additional monitoring and operational costs expected to ensure a 98 percent minimum destruction efficiency and found that it would not be cost-effective to require control of storage vessels with the potential for VOC emissions below 12 tpy or methane emissions below 40 tpy. However, at 95 percent reduction, it is considered cost-effective to require control of storage vessels with potential VOC emissions of 6 tpy and methane

²⁰⁸ See Document ID No. EPA-HQ-OAR-2021-0317-0749.

²⁰⁹ See Document ID Nos. EPA-HQ-OAR-2021-0317-0604, EPA-HQ-OAR-2021-0317-0605, EPA-HQ-OAR-2021-0317-0844, and EPA-HQ-OAR-2021-0317-1286.

²¹⁰ See Document ID Nos. EPA-HQ-OAR-2021-0317-0599, EPA-HQ-OAR-2021-0317-0808, and EPA-HQ-OAR-2021-0317-0831.

emissions of 20 tpy.²¹¹ Therefore, requiring 98 percent reduction of methane and VOC results in the control of fewer storage vessels, and thus result in fewer overall emissions reductions. Consequently, the EPA is proposing to maintain that the BSER for storage vessel affected facilities is 95 percent reduction, as described in section IV.J of this preamble. Because the analysis conducted covers the range of control device sizes utilized by other affected facilities, similar impacts on the BSER analysis are expected. Furthermore, because individual sites would utilize a single control device for all affected/designated facilities, it does not make sense to require different emissions reduction standards for different affected/designated facilities. For more detail on the analysis conducted to assess the costs of control device monitoring see memorandum Analysis of Monitoring Costs to Ensure 98 Percent Destruction Efficiency, available in the docket for this action (Docket ID No. EPA-HQ-OAR-2021-0317).

3. Summary of Proposed Requirements for NSPS OOOOb and EG OOOOc

The EPA is proposing that control devices used for any affected facility must demonstrate that they meet a 95 percent VOC and methane emission reduction requirement through a performance test (or for condensers and carbon absorbers, through a design evaluation) or manufacturer's performance test.

In NSPS OOOOb and EG OOOOc, we are proposing the same control device requirements for thermal vapor incinerators (including thermal oxidizers and enclosed combustors) for which temperature is correlated with destruction efficiency, catalytic vapor incinerators, condensers, and carbon adsorption systems as were required in NSPS OOOOa (for centrifugal compressor affected facilities). We are proposing that these requirements apply to all affected facilities complying with the standards by using one of these control devices.

The EPA is proposing requirements for flares to be designed and operated according to the provisions in 40 CFR 60.18 for all flares, regardless of the affected facility type, except as noted below for pressure-assisted devices.

Further, we are proposing to require these same general requirements for enclosed combustors not tested by the manufacturer and for which temperature is not correlated with control device performance. NSPS OOOO and NSPS OOOOa do not include criteria to determine that temperature is (or is not) correlated with control device performance. Criteria where temperature is well correlated could include requirements that air flow to the burner is controlled and that there is sufficient refractory in the stack to maintain high temperature even at low flows. The EPA requests comment on whether criteria should be developed for NSPS OOOOb and EG OOOOc, which delineate when temperature is (or is not) correlated with control device performance, and if so, in addition to the criteria above, what criteria would be appropriate. The EPA is proposing to include consistent initial and continuous compliance requirements to ensure flares and enclosed combustion devices are maintaining efficient combustion. As discussed previously in this section, there are 4 critical requirements in 40 CFR 60.18 that must be met to ensure proper destruction efficiency.²¹² The proposed continuous compliance requirements for each of these critical elements are described in the following paragraphs.

First, the EPA is proposing to require all flares and enclosed combustion devices²¹³ to have a continuous pilot flame and install a continuous parameter monitoring system capable of continuously (at least once every 5 minutes) monitoring for the presence of a pilot or combustion flame. This is in keeping with the requirements of the General Provisions to require a continuous pilot flame. The EPA is specifying more frequent monitoring intervals for the pilot light than for other continuous parameter monitoring systems (which require a minimum of one reading per hour) because the destruction efficiency will rapidly fall to zero in the absence of a pilot or combustion flame. Therefore, we determined that more frequent readings were needed for the pilot flame monitoring system to ensure the flare or enclosed combustion device achieves 95

percent destruction efficiency at all times.

Second, the EPA is proposing to require inspections to monitor for visible emissions using section 11 of EPA Method 22 of appendix A-7 of part 60 (EPA Method 22). The observation period for the EPA Method 22 inspection would be 15 minutes. Visible emissions longer than 1 minute during the 15-minute period would be a deviation of the standard. This is consistent with similar requirements in NSPS OOOOa. The EPA is proposing that these inspections would occur monthly, and at other times as requested by the Administrator. For example, if the Administrator observed a flare with intermittent visible emissions, the Administrator may require the owner or operator to conduct an EPA Method 22 inspection to determine whether the flare is exceeding the visible emissions limit.

Next, the EPA is proposing that flares and enclosed combustion devices monitor the net heating value of the vent gas sent to the flare or combustor. Owners and operators would install a continuous parameter monitoring system, such as a calorimeter, to continuously determine the net heating value of the gas sent to the flare or combustor. Alternatively, the owner or operator could conduct an initial assessment to demonstrate that the net heating value of the vent gas sent to the flare or combustor consistently exceeds the required minimum net heating value in 40 CFR 60.18 or the minimum net heating value proposed for pressure-assisted flares.²¹⁴ The proposed initial demonstration consists of hourly monitoring over 10 days. The EPA is proposing this frequency and duration of monitoring in order to provide a large sampling set by which to assess the variability of the vent gas sent to the combustion device and to adequately characterize the tails of the distribution. When actively controlling net heating value, operators will generally control at a set point 10 to 20 percent higher than the limit to ensure they are meeting the limit at all times. Therefore, the EPA concluded that a 20 percent cushion was a reasonable minimum value for "well above the threshold." To be considered consistently above the net heating value threshold, greater than 90 percent of the measurements would need to be "well above the threshold," with no readings below the threshold. Based on these considerations, the EPA

²¹¹ The costs associated with the monitoring requirements necessary to ensure a 95 percent reduction in methane and VOC emissions is achieved were included in the cost analysis provided in the November 2021 proposal. See the 2021 TSD for additional details at Document ID No. EPA-HQ-OAR-2021-0317-0166 and accompanying spreadsheets at Document ID No. EPA-HQ-OAR-2021-0317-0039.

²¹² The four requirements are: (1) Continuous pilot flame; (2) no visible emissions except for a total of 5 minutes in a 2-hour period; (3) minimum net heating value of gas sent to the flare; and (4) maximum flare tip velocity.

²¹³ This discussion in the rest of this section applies to those enclosed combustion devices for which temperature is not correlated with destruction efficiency.

²¹⁴ Pressure-assisted devices are not required to comply with the vent gas net heating value in 40 CFR 60.18. The EPA is proposing alternative net heating value requirements for these devices as discussed in detail below.

is proposing that if there are no hourly gas samples with a net heating value below the required minimum net heating value and 20 or fewer hourly gas samples are less than 1.2 times the required minimum net heating value, then the gas stream is considered to be “consistently above the threshold” and on-going continuous monitoring is not required.

Lastly, to ensure compliance with the maximum flare tip velocity requirement in 40 CFR 60.18, for flares and enclosed combustion devices, the EPA is proposing to require installation of a continuous parameter monitoring system to determine the flow of gas sent to the flare or combustor, except as noted below for pressure-assisted devices. Alternatively, the owner or operator may conduct an initial engineering assessment of the sources vented to the flare to demonstrate that, based on the maximum pressure of these sources, the maximum possible gas flow rate would not exceed the allowed maximum flare tip velocity in 40 CFR 60.18 or the maximum design flow rate of the enclosed combustor.

The EPA has also determined that combustion devices may be operating at gas flow rates that are too low to support efficient combustion, resulting in uncombusted vented emissions. To address this issue, the EPA is proposing to require that manufacturers establish both a minimum and maximum flow rate during the testing performed under 40 CFR 60.5413b(d) and 40 CFR 60.5413c(d) to ensure these devices operate efficiently in the field. Combustion control devices previously tested by the manufacturer for which the manufacturer was able to demonstrate the control device meets the performance requirements would not need to perform new performance tests. The zero-level at which the combustion control device was tested will be extracted from the previously submitted performance test report and added to the information on the EPA’s website.²¹⁵ For flares and enclosed combustion devices not tested by the manufacturer under 40 CFR 60.5413b(d) or 40 CFR 60.5413c(d), the owner or operator would be required to establish a minimum vent gas flow rate based on manufacturer recommendations. Owners and operators would be required to continuously monitor the vent gas flow rate to ensure that it is above this minimum level whenever vent gas is sent to the flare or enclosed

combustion device. As an option, the owner or operator could install a backpressure preventer which is set to operate at or above the minimum inlet gas flow rate. The EPA is soliciting comment on this additional requirement and whether there are additional situations where continuous monitoring of the vent gas flow rate is unnecessary.

For pressure-assisted devices, the EPA is proposing to include special provisions in NSPS OOOOb/EG OOOOc, which include a minimum net heating value (NHV) of the gas sent to the flare/combustor of 800 British thermal units per standard cubic feet (Btu/scf) and an exemption from the maximum velocity requirements in 40 CFR 60.18.²¹⁶ Pressure-assisted devices are designed to operate at high flare or burner tip velocities and use this velocity to improve mixing of the flared gas with surrounding air. For good combustion efficiency at these high velocities, the flared gas must have higher heat content than a non-pressure-assisted flare. The EPA evaluated pressure-assisted flares and determined that these flares must have flare gas with an NHV of 800 Btu/scf or higher to work efficiently.²¹⁷ Also, because the burners are specifically designed to have high flow rates, the burner tip velocity typically exceeds the maximum flare tip velocity limit in 40 CFR 60.18. The maximum velocity limits in 40 CFR 60.18 were set to prevent flame “lift off” or flame instability from conventional flare tips. However, pressure-assisted flare tips are specifically designed to operate efficiently at much higher velocities. The EPA found that pressure assisted flares can operate efficiently at these higher velocities. Therefore, the EPA is proposing that pressure-assisted devices would not be subject to the maximum flare tip velocity limit.

Finally, the EPA is proposing operating requirements at 40 CFR 60.5417b(f) (and 40 CFR 60.5417c(f)) and specifying what constitutes a deviation at 40 CFR 60.5417b(g) (and 40 CFR 60.5417c(g)) that are consistent

with the operating and monitoring requirements outlined in this section and that are consistent across all affected facilities using control devices. Further, these sections are referenced in the recordkeeping and reporting requirements for each affected facility so that the reporting requirements for affected facilities that use control devices to comply with the standard have consistent control device reporting requirements regardless of the type of affected facility. The EPA is soliciting comment on all proposed requirements for control devices described within this section.

I. Reciprocating Compressors

In a reciprocating compressor, natural gas enters the suction manifold and then flows into a compression cylinder, where it is compressed by a piston driven in a reciprocating motion by the crankshaft, which is powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time, during operation of the compressor, the rings become worn, and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder.

1. NSPS OOOOb

a. November 2021 Proposal

Based on the analysis presented in section XII.E.1 of the November 2021 proposal preamble (86 FR 63214–63220; November 15, 2021), the proposed BSE for NSPS OOOOb for reducing GHGs and VOC from new reciprocating compressors was the replacement of the rod packing based on an annual monitoring threshold. Under the November 2021 proposal, the owner or operator of a reciprocating compressor affected facility would have been required to monitor the rod packing emissions annually by conducting flow rate measurements. When the measured flow rate exceeded 2 scfm (in pressurized mode), replacement of the rod packing would have been required. As indicated at proposal, the 2 scfm flow rate threshold was established based on manufacturer guidelines indicating that a flow rate of 2 scfm or greater was considered indicative of rod packing failure.²¹⁹ Alternatively, the November 2021 proposal would have

²¹⁵ Information on combustion control devices tested by the manufacturer can be found at: <https://www.epa.gov/stationary-sources-air-pollution/performance-testing-combustion-control-devices-manufacturers>.

²¹⁶ Pressure-assisted devices would still be subject to the requirements for a continuous pilot flame and the visible emissions requirement, as well as the requirement to continuously monitor (or perform an assessment) on the NHV of the vent gas.

²¹⁷ “Notice of Final Approval for the Operation of a Pressure-Assisted Multi-Point Ground Flare at Occidental Chemical Corporation,” 81 FR 23480, April 21, 2016, and “Notice of Final Approval for an Alternative Means of Emission Limitation at ExxonMobil Corporation; Marathon Petroleum Company, LP (for Itself and on Behalf of Its Subsidiary, Blanchard Refining, LLC); Chalmette Refining, LLC; and LACC, LLC,” 83 FR 46939, September 17, 2018.

²¹⁸ Because pressure-assisted flares generally do not use assist gas, combustion zone NHV is the same as the flare gas NHV.

²¹⁹ 86 FR 63218 (November 15, 2021).

also provided owners and operators the option of routing rod packing emissions to a process via a CVS under negative pressure in order to comply with the rule. The proposed option to route to a process is allowed as an alternative under NSPS OOOOa because implementing this option, where feasible, would achieve greater emission reductions than the primary fixed schedule rod packing replacement BSER requirement under NSPS OOOOa.

b. Changes From November 2021 Proposal

The BSER analysis is unchanged from what was presented in the November 2021 proposal (see 86 FR 63214–63220, section XII.E. Reciprocating Compressors). The EPA is proposing changes and specific clarifications to the November 2021 proposal standards for NSPS OOOOb. For the proposed replacement of the rod packing based on an emission limit and annual measurement requirement, we are proposing: (1) To clarify that the standard of performance is a numeric standard (not a work practice standard) of 2 scfm, (2) to allow for repair (in addition to replacement) of the rod packing in order to maintain an emission rate at or below 2 scfm; (3) to allow for monitoring based on 8,760 hours of operation instead of based on a calendar year. We are also proposing regulatory text that clearly defines the required flow rate measurement methods and/or procedures, repair and replacement requirements, and recordkeeping and reporting requirements. For the alternative option of routing rod packing emissions to a process via a CVS under negative pressure, we are proposing to remove the negative pressure requirement. These changes take into account comments received on the November 2021 proposal, as explained below.

The basis for the proposed changes and clarifications to the replacement of the rod packing based on a flow rate monitoring measurement for reciprocating compressors is presented in section IV.I.1.b.i of this preamble. The basis for the proposed change to the alternative option of routing rod packing emissions to a process via a CVS under negative pressure is presented in section IV.I.1.b.ii of this preamble. A summary of the proposed reciprocating compressor standards is presented in section IV.I.1.b.iii of this preamble.

i. Numerical Emission Limit Standard Proposed Changes

Changes to Format of the Standard. In re-considering the BSER determination and standards for reciprocating

compressors proposed in November 2021, the EPA recognized that it is feasible to prescribe a standard of performance, rather than a work practice standard,²²⁰ for reciprocating compressors. Accordingly, the EPA is now proposing a numerical emission limit requirement. The major difference between this standard and what the EPA proposed in November 2021 is that under this supplemental proposal, owners and operators would be required to maintain emissions at or below the emission limit (emission flow rate of 2 scfm) whereas under the November proposal, owners or operators would have been required to change out the rod packing only after discovering an exceedance of 2 scfm. The BSER is replacement of the rod packing and/or other necessary repair and maintenance activities to maintain emissions at or below 2 scfm.

Repair or Replacement. Commenters on the November 2021 proposal urged the EPA to allow for repair as an alternative to complete replacement of rod packing. The commenters pointed out that allowing repair would be consistent with California's reciprocating compressor rule requirements. See 17 California Code of Regulation section 95668(c)(3)(D).²²¹ One commenter noted that, for older units, replacing the rod packing does not always address emissions levels, as other maintenance issues can contribute to cylinder emissions, such as issues with the rod itself. The commenter added that providing the flexibility to repair as well as replace the rod packing could significantly impact personnel costs—while rod packing replacement on older units can require approximately 32-man hours per cylinder, a repair may entail a significantly lower level of effort and hours of labor.²²²

The EPA agrees with the commenters' suggestion. The intent of the proposed reciprocating compressor standard was

²²⁰ Under CAA section 111(h)(1), work practice standards are appropriate only where "it is not feasible to prescribe or enforce a standard of performance." CAA section 111(h)(2) defines such infeasibility as "any situation in which the Administrator determines that (A) a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, state, or local law, or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations."

²²¹ Final Regulation Order. California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4. Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.

²²² See Document ID No. EPA-HQ-OAR-2021-0317-0817.

to require that the volumetric flow rate be maintained at or below 2 scfm. If repair can maintain the volumetric flowrate at or below 2 scfm without the need to replace the rod packing, the intent of the proposed standards would be met. Thus, under the proposed numerical emission limit, an owner or operator would be allowed to repair or replace the rod packing in order to maintain the volumetric flow rate at or below the 2 scfm emission limit.

Hours of Operation Versus Calendar Year. Commenters²²³ on the November 2021 proposal recommended that the EPA consider requiring flow rate monitoring based on a compressor's hours of operation totaling one year (*i.e.*, 8,760 hours) in lieu of requiring annual flow rate measurements based on a calendar year. Commenters stated that using the compressor's hours of operation would ensure that undue burden is not placed on owners and operators where compressors are not operational for multiple months or are used intermittently. The commenters explained that basing flow rate measurement requirements on a reciprocating compressor's hours of operation would allow owners and operators to stagger maintenance activity throughout the year. The comments further suggested that the EPA consider exemptions from the rule for limited-use reciprocating compressors and changing the flow rate measurement monitoring requirement frequency to every 2 years.

In order to address limited-use reciprocating compressors and to allow owners and operators flexibility when planning maintenance, the EPA agrees that it makes sense to require periodic reciprocating compressor flow rate monitoring based on the hours of operation (*i.e.*, 8,760 hours) in lieu of requiring monitoring based on a calendar year. Thus, we are proposing to allow for periodic flow rate monitoring based on 8,760 hours of operation instead of requiring monitoring on a calendar year basis.

Regulation Clarifications. Several commenters²²⁴ requested that the EPA clearly state in the rule that the GHGRP subpart W methods be allowed for the flow rate measurements. These commenters also requested that the EPA clearly state the proposed reciprocating compressor annual monitoring threshold and the repair and rod packing replacement requirements. Specifically, they sought certainty

²²³ See Document ID No. EPA-HQ-OAR-2021-0317-0415.

²²⁴ See Document ID Nos. EPA-HQ-OAR-2021-0317-0415, and EPA-HQ-OAR-2021-0317-1375.

regarding the schedule for repair and “delay of repair” criteria to ensure unnecessary restrictions are not placed on repair schedules, and a clear explanation of operating requirements for measurement (*i.e.*, when the unit is operating).

The EPA considered the commenters’ specific requests for clarity within the requirements when developing the proposed regulatory text and the desire to be consistent with the GHGRP subpart W. We recognize this desire however we are concerned the flow rate measurements methods under GHGRP subpart W are not as well-defined or prescriptive as the methods the EPA requires for demonstrating compliance with an emission standard. Instead, the EPA is proposing the use of volumetric flow rate which meet the requirements of Method 2D (40 CFR part 60, appendix A) for testing emissions from reciprocating compressor rod packing and the use of a high-volume sampler to measure the emissions from proposing either the reciprocating compressor rod packing or centrifugal compressor seal vents (dry seals for NSPS OOOOb and all centrifugal compressor wet and dry seals for EG OOOOc).²²⁵ For the high-volume sampler, instead of relying on manufacturer defined procedures required in GHGRP Subpart W, the EPA is proposing a defined set of procedures and performance objectives to ensure consistent application of these samplers. In an effort to allow for additional innovation for these types of measurements, the EPA is also proposing to allow other methods, subject to Administrator approval, that have been validated according to Method 301 (40 CFR part 63, appendix A). The EPA solicits comment on the use of the proposed performance test methods and solicits comment on other methodologies that could be used to demonstrate compliance with the centrifugal compressor dry seal vent, centrifugal compressors for EG OOOOc, and reciprocating compressor rod packing emission standards.

The proposed NSPS OOOOb regulatory text also specifies that flow rate monitoring be conducted in operating or standby pressurized mode, and “repair” and “delay of repair” schedules, in addition to other clarifying requirements. The EPA is proposing to require conducting flow rate measurements during operating or standby pressurized mode because the measured emissions would be representative of actual emissions during operations. Repair schedules are

proposed to require repair of equipment in a timely manner to mitigate emissions. Delay of repair would be allowed when owners and operators required more time to repair equipment based on scenarios beyond the owner or operator’s control (*e.g.*, issues with availability of equipment or where repair necessitates a compressor shutdown when redundancy of compressors is not available).

ii. Routing Emissions to a Process Via a Closed Vent System Under Negative Pressure

The EPA received comments on the November 2021 proposal related to its proposed compliance alternative of routing rod packing emissions to a process via a CVS under negative pressure. One commenter²²⁶ noted that routing emissions to a process should not require negative pressure, stating that some pressure differential is required to take gas out of the rod packing vent and into the desired location. This commenter further stated that the use of negative pressure can raise safety and operational issues, and that operating a crankcase collection system under negative pressure (*i.e.*, in a vacuum) creates the possibility of introducing oxygen into the system. This commenter added that allowing for pressure differential without requiring operation under negative pressure could lead to larger emission reductions overall, and that the proposed negative pressure requirement eliminates the ability to use technologies that could reduce emissions further. Another commenter²²⁷ similarly reported that the use of negative pressure presents safety concerns of creating an explosive mixture of natural gas and atmospheric air, should there be any leak between the negative pressure source and the packing vent. The commenter stated that as long as the packing vent recovery system is at a lower pressure; the packing vent gas will be recovered without leaking to atmosphere and there will be no risk of introducing atmospheric air to the natural gas.

The November 2021 proposal included the requirement to route rod packing emissions to a process via a CVS under negative pressure based on information submitted by a petitioner²²⁸ on NSPS OOOO that requested/suggested an alternative standard that would result in equal to or

greater emissions reductions than the rod packing replacement standard. The petitioner’s suggested alternative standard was to capture emissions under negative pressure, thus allowing all emissions to be routed to the engine. The petitioner suggested achieving this by recovering vented emissions from the rod packing under negative pressure and routing these emissions of otherwise vented gas to the air intake of a reciprocating internal combustion engine that would burn the gas as fuel to augment the normal fuel supply. The petitioner reasoned that emission reductions would be commensurate with, or better than, the reductions from the rod packing replacement standard. The EPA acknowledged at the time (2014) that this technology may not be applicable or feasible for every compressor installation and situation. However, the EPA proposed this option as an alternative to the rod packing replacement standards for those instances where it could be applied.²²⁹

In light of the comments received on the November 2021 proposal, and an increased understanding of this type of approach, the EPA is proposing to revise the compliance alternative by continuing to allow emissions to be routed to a process via a CVS but removing the requirement for this to occur under negative pressure. The intent of requiring “negative pressure” was that there be sufficient pressure differential such that emissions would be routed from the compressor via the CVS to the process. The EPA did not intend to create a safety issue or limit technologies that would achieve equivalent or greater emission reductions than the work practice standard. Since such a pressure differential would be created when the reciprocating compressor is operating, specifying that emissions need to be routed to a process via a CVS under negative pressure is unnecessary. As the commenter noted, this is already understood for other sources where the standards require routing of emissions through a CVS to a process or control device.

As noted above, routing emissions to a process is an existing compliance option under NSPS OOOO and NSPS OOOOa and the EPA has assumed that the emissions reduced by this option, where feasible to implement, are greater than those achieved by the proposed BSER requirement to implement maintenance and repair activities to maintain the flow rate (as a surrogate for emissions) from the reciprocating compressor rod packing at or below 2

²²⁵ See section IV.G. for discussion on centrifugal compressors.

²²⁶ See Document ID No. EPA–HQ–OAR–2021–0317–0817.

²²⁷ See Document ID No. EPA–HQ–OAR–2021–0317–0745.

²²⁸ Letter from Veronica Nasser, REM Technologies, Inc., to Lisa P. Jackson, EPA Administrator, Petition for Reconsideration.

²²⁹ See 79 FR 41760–41761 (July 17, 2014).

scfm. The EPA solicits comment on its assumption that the emissions reduced by requiring the capture of gas and routing to a process are greater than the requirement to maintain the flow rate from the reciprocating compressor rod packing at or below 2 scfm. The EPA also is soliciting comment on the prevalence of owners and operators complying with NSPS OOOO and NSPS OOOOa by capturing and routing emissions from the reciprocating compressor rod packing to a process.

iii. Summary of Proposed Standards

Affected Facility. The EPA is proposing to define a reciprocating compressor affected facility as each reciprocating compressor, which is a single reciprocating compressor. A reciprocating compressor located at a well site is not an affected facility under this subpart. A reciprocating compressor located at a centralized production facility is an affected facility under this subpart.

Numerical Emission Limit Standards. The proposed NSPS OOOOb standard of performance for reciprocating compressor affected facilities is a numerical emission limit of 2 scfm (in operating or standby pressurized mode). The volumetric flow rate measurement from each reciprocating rod packing must be maintained to be less than or equal to a flow rate of 2 scfm (in operating or standby pressurized mode). The proposed BSER is to repair or replace the rod packing and to conduct other necessary repair and maintenance in order to maintain the emission rate at or below 2 scfm. The proposed monitoring requirements are to conduct volumetric flow rate measurements from each reciprocating compressor rod packing using the proposed monitoring methods in 40 CFR 60.5386b (which includes similar screening and flow rate measurement methods as required under GHGRP subpart W).

The EPA is proposing to require the first volumetric flow rate measurements from a reciprocating compressor affected facility on or before 8,760 hours of operation. Subsequent volumetric emissions measurements from a reciprocating compressor affected facility would be required on or before 8,760 hours of operation after the previous measurement, or on or before 8,760 hours of operation after the date of the most recent reciprocating compressor rod packing replacement, whichever is later. Preventative maintenance or other corrective actions may be necessary (in addition to monitoring every 8,760 hours of operation) in order for owners or operators to ensure compliance at all

times (consistent with the general duty clause 40 CFR 60.5470b(b)) with the required flow rate of 2 scfm (or less).

Routing Emissions From the Rod Packing to a Process. Alternatively, an owner or operator may choose to comply with NSPS OOOOb by routing emissions from the rod packing to a process through a CVS. This option would achieve greater than or equal to the 2 scfm numerical limit as emissions would be routed to a process via a closed system which would limit emissions from the rod packing from being vented to the atmosphere. An owner or operator must ensure that the CVS is designed to capture and route all gases, vapors, and fumes to a process (40 CFR 60.5411b(a) and (c)). Additionally, an owner or operator would be required to design and operate the CVS with no detectable emissions and would be subject to bypass requirements (as applicable). Initial, monthly, and annual inspections (using OGI, EPA Method 21, or AVO (for monthly inspections only)) would be required to check for defects and detectable emissions.

Recordkeeping and Reporting Requirements. Owners or operators complying with the numerical emission limit must track and report in their annual report the cumulative number of hours of operation of each reciprocating compressor since startup, since the previous screening/volumetric flow rate emissions measurement, or since the previous reciprocating compressor repair/replacement of rod packing, as applicable. Their annual report must also include a description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable. Lastly, owners or operators must maintain records and report each deviation from the emission limit standard that occurred during the reporting period, the date and time the deviation began, duration of the deviation and a description of the deviation.

For a reciprocating compressor affected facility complying with the routing emissions from the rod packing to a process through a CVS, an owner or operator would be required to maintain records and report each reciprocating compressor that was constructed, modified, or reconstructed during the reporting period that is complying by using this option. In instances where a deviation from the standard has occurred during the reporting period, an owner or operator would be required to provide information on the date and time the deviation began, the duration of the deviation, and a description of the

deviation. Additionally, they would be required to report of the dates of each cover and CVS inspection, whether defects or leaks are identified, and the date of repair or the date of anticipated repair if repair is delayed would be included in the annual report. Where bypass requirements apply, the date and time of each bypass alarm or each instance the key is checked out would be included in the annual report.

2. EG OOOOc

Based on the analysis presented in section XII.E.2 of the November 2021 proposal preamble (86 FR 63214–63220; November 15, 2021), the proposed BSER for EG OOOOc for reducing methane emissions from existing reciprocating compressors was the replacement of the rod packing based on an annual monitoring threshold. Under the November 2021 proposal, the owner or operator of a reciprocating compressor designated facility would have been required to monitor the rod packing emissions annually by conducting flow rate measurements. When the measured flow rate exceeded 2 scfm (in pressurized mode), replacement of the rod packing would have been required. Alternatively, the November 2021 proposal would have also provided owners and operators the compliance alternative of routing rod packing emissions to a process via a CVS under negative pressure to comply with the rule.

a. Standard Proposed Changes

Based on the same public comment considerations and reasoning as explained above (see sections IV.I.1.b.i and ii of this preamble) for the proposed NSPS OOOOb reciprocating compressor rule changes, the EPA is proposing the same changes and requirements under EG OOOOc as presumptive standards for designated facilities.

b. Summary of Proposed Standards

Designated Facility. The EPA is proposing to define a reciprocating compressor designated facility as each reciprocating compressor, which is a single reciprocating compressor. A reciprocating compressor located at a well site is not a designated facility under this subpart. A reciprocating compressor located at a centralized production facility is a designated facility under this subpart.

Proposed Presumptive Standards. The proposed presumptive standards and BSER for existing reciprocating compressors are the same as those being proposed for new reciprocating compressors (see section IV.I.1.b.iii of this preamble). The requirements to

monitor the volumetric flow rate from a reciprocating compressor based on hours of operation, and to repair or replace the rod packing and to conduct any necessary repair and maintenance in order to maintain a flow rate at or below 2 scfm, would not result in any additional capital expenditures or retrofit considerations that would warrant different requirements. Alternatively, as with new sources, owners or operators of existing reciprocating compressors would be allowed to comply by routing rod packing emissions to a process via a CVS.

J. Storage Vessels

1. NSPS OOOOb

a. November 2021 Proposal

Storage Vessel Affected Facility. In the November 2021 proposal, the EPA proposed to retain the current VOC standards for storage vessels (95 percent reduction) and proposed for the first-time standards for reducing methane emissions from storage vessels (95 reduction). In addition, for both VOC and methane standards, the EPA proposed to define a storage vessel affected facility as a tank battery or a single storage vessel that is not part of a tank battery, with the potential for VOC emissions of 6 tpy or greater.²³⁰ The standards in NSPS OOOOa apply to single storage vessels with potential VOC emissions of 6 tpy or greater, although the EPA has long observed that these storage vessels are typically located as part of a tank battery. See 76 FR 52738, 52763 (August 23, 2011). Further, the 6 tpy applicability threshold was established by directly correlating the cost to control different levels of VOC emissions based on the use of a single vapor recovery or combustion control device, regardless of the number of storage vessels routing emissions to that control device, and control of 6 tpy VOC was cost effective using that single control device. *Id.* at 52763–64. Therefore, in the November 2021 proposal, the EPA proposed to define a tank battery as a group of storage vessels that are physically adjacent and that receive fluids from the same source (e.g., well, process unit, compressor station, or set of wells, process units, or compressor stations) or which are manifolded together for liquid or vapor transfer. The EPA proposed that to determine whether a single storage vessel is an affected

facility, the owner or operator would compare the 6 tpy VOC threshold to the potential emissions from that individual storage vessel; to determine whether a tank battery is an affected facility, the owner or operator would compare the 6 tpy VOC threshold to the aggregate potential emissions from the group of storage vessels in the tank battery. For new, modified, or reconstructed sources, the EPA proposed that if the potential VOC emissions from a storage vessel or tank battery exceeds the 6 tpy threshold, then it is a storage vessel affected facility and controls would be required. Additionally, the EPA proposed an emissions limit requiring 95 percent reduction as the BSER for reducing VOC and methane emissions from new, modified, or reconstructed storage vessel affected facilities. The EPA also requested comment on increasing combustion efficiency to 98 percent control and on requiring additional monitoring of the control device. See IV.G of this preamble for discussion related to combustion control devices.

Modification. In the November 2021 proposal, the EPA proposed specific provisions to specify what circumstances constitute a modification of an existing storage vessel or tank battery, and thus subject it to the proposed NSPS OOOOb. The EPA proposed that a single storage vessel or tank battery is modified when certain physical or operational changes are made (86 FR 63178; November 15, 2021) to the single storage vessel or tank battery which result in an increase in the potential methane or VOC emissions. The EPA proposed that the owner or operator would be required to recalculate the potential VOC emissions when any of these actions occurred on an existing tank battery, to determine if a modification occurred. The EPA proposed that an existing tank battery would become subject to the proposed NSPS OOOOb if it is modified pursuant to this definition of modification and its potential VOC emissions exceeded the proposed 6 tpy VOC emissions threshold.

Legally and Practicably Enforceable. The EPA proposed to clarify the term “legally and practicably enforceable” as it related to determining applicability of the storage vessel standards. The intent of this proposed definition (86 FR 63201; November 15, 2021) was to provide clarity to owners and operators claiming the storage vessel is not an affected facility in NSPS OOOOb, due to legally and practicably enforceable limits that limit their potential for VOC emissions below 6 tpy.

b. Changes From November 2021 Proposal

Storage Vessel Affected Facility. In this supplemental proposal, the EPA is proposing that a storage vessel affected facility is a tank battery which has the potential for VOC emissions equal to or greater than 6 tpy or the potential for methane emissions equal to or greater than 20 tpy. Specifically, the EPA is proposing to define a tank battery as a group of all storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel if there is only one storage vessel is present, or the individual storage vessels at the site are not manifolded for liquid transfer. Commenters generally supported basing the potential for emissions on a tank battery instead of an individual storage vessel. The EPA received several comments that suggested changes to the definition of tank battery relating to how the tanks were manifolded and the proximity of tanks within the tank battery. Specifically, these commenters recommended that the definition of tank battery not include the term “adjacent” and should be based on tanks that are manifolded by liquid line.²³¹ Commenters suggested these changes to avoid confusion around applicability and to align with existing state programs.²³² The EPA agrees that these changes reflect our intent that a group of storage vessels which are manifolded together by liquid line operate as a system and, as such, share the same control, the cost of which was the basis for defining the applicability threshold; the total throughput to the tank battery is the basis for determining the potential for VOC and methane emissions for the tank battery, based on the maximum average daily throughput to the tank battery. This rationale holds regardless of the physical proximity to each other and therefore the term “adjacent” does not add additional clarity. Also, because tank batteries with the potential for VOC and methane emissions (greater than or equal to the thresholds) are: (1) Storage vessel affected facilities which require control; and (2) those standards require that all vapors from the tank battery are routed through a CVS (*i.e.*, manifolded), it is not necessary to include the provision that vapor lines are manifolded in the definition of tank battery.

As stated above, the EPA is also proposing to include the 20 tpy

²³⁰ For the reasons explained in the November 2021 proposal, the 6 tpy VOC applicability threshold would apply to both methane and VOC standards.

²³¹ See Document ID Nos. EPA–HQ–OAR–2021–0317–0810, EPA–HQ–OAR–2021–0317–0814 and EPA–HQ–OAR–2021–0317–0831.

²³² See Document ID Nos. EPA–HQ–OAR–2021–0317–0808 and EPA–HQ–OAR–2021–0317–0831.

potential for methane emission threshold for determining applicability to NSPS OOOOb. As discussed in the November 2021 proposal, the EPA determined that it is cost-effective to reduce methane emissions by 95 percent from existing tank batteries with potential methane emissions of 20 tpy. The EPA focused the November 2021 proposed NSPS OOOOb requirements on the 6 tpy VOC threshold because the EPA expects that most tank batteries will exceed the 6 tpy VOC threshold well before they exceed the 20 tpy methane threshold. However, based on our cost estimates, the EPA determined it is cost effective to control tank batteries if their methane emissions exceed 20 tpy, but the potential VOC emissions remain below 6 tpy. As such, in the unusual case that the methane threshold is triggered prior to the VOC threshold, the EPA determined it necessary to directly include the 20 tpy potential methane emissions threshold in the storage vessel affected facility definition.

The EPA also is proposing that a “generally accepted model or calculation methodology” used to determine VOC and methane emissions must account for flashing, working, and breathing losses. As discussed in the November 2021 proposal, both methane and VOC emissions from storage vessels are a result of working, breathing, and flashing losses. Flashing losses occur when a liquid with dissolved gases is transferred from a vessel with higher pressure (e.g., separator) to a vessel with lower pressure (e.g., storage vessel), thus allowing dissolved gases and a portion of the liquid to vaporize or flash. In the Crude Oil and Natural Gas source category, flashing losses occur when crude oils or condensates flow into a storage vessel from a separator operated at a higher pressure. Typically, the higher the operating pressure of the upstream separator, the greater the flash emissions from the storage vessel. See 86 FR 63198 (November 15, 2021). For tank batteries with flashing losses, those emissions can dwarf working and breathing losses from the same tank battery. There are many “generally accepted” models or calculation methodologies for estimating storage vessel emissions, but they do not all estimate flash emissions. Therefore, it is important to specify in the rule the EPA’s requirement that emissions calculations account for such emissions when flash emissions occur.

Additionally, the EPA is including in this supplemental proposal regulatory text which instructs the owner or operator on how to determine the potential for VOC or methane emissions

as the cumulative emissions from all storage vessels within the tank battery according to certain timelines; for each tank battery located at a well site or centralized production facility the determination must occur 30 days after startup of production, or within 30 days after a physical or operational action which may trigger a modification or reconstruction; or for each tank battery located at a compressor station or onshore natural gas processing plan, the determination must occur prior to startup of the compressor station or onshore natural gas processing plant (or within 30 days after an action which may trigger reconstruction or modification). These timelines are consistent with the timelines provided in NSPS OOOOa for determining the potential for VOC emissions after startup of production (for a well site) or startup of the compressor station or onshore natural gas processing plant but are being proposed to also include timelines for centralized production facilities as well as timelines for determining the potential for VOC and methane emissions following an action which may trigger reconstruction or modification. The EPA believes this proposed regulatory text will provide direction and clarity to owners and operators for when the potential for VOC and methane emissions determinations must be made based on potentially triggering events. See the following discussion regarding reconstruction and modification.

Reconstruction and Modification. The EPA is proposing the following changes from the November 2021 proposal related to definitions for reconstruction and modification for storage vessels. This proposal includes a definition of “reconstruction” as well as “modification” at 40 CFR 60.5365b(e)(3) for determining if an existing tank battery becomes a storage vessel affected facility subject to NSPS OOOOb. The proposed rule will apply to sources that are new, reconstructed, and modified sources after November 15, 2021. In the November 2021 proposal the EPA discussed our rationale for proposing specific actions which lead to an increase in VOC and methane emissions and therefore, constitute a modification of an existing tank battery. Generally, that rationale was to provide clarity on actions which are considered a modification of a tank battery. See 86 FR 63198 (November 15, 2021).

In this proposed rule, the EPA is proposing two actions which constitute reconstruction: (1) Over half of the storage vessels are replaced in an existing tank battery that consists of more than one storage vessel; or (2) the

provisions of 40 CFR 60.15 are met for the existing tank battery that consists of a single storage vessel. Section 60.15 of the General Provisions to part 60 states that reconstruction occurs when the replacement of new components exceeds 50 percent of the capital cost that would be required to construct a comparable entirely new facility and it is technologically and economically feasible to meet the applicable standard under part 60. Reconstruction applies irrespective of any change in emissions rate. “Fixed” capital cost is further defined at 40 CFR 60.15(c) as the capital needed to provide all of the depreciable components and 40 CFR 60.15(g) allows for individual subparts to include specific provisions to refine or delimit the concept of reconstruction. Finally, 40 CFR 60.15(d) and (e) provide that the owner or operator must notify the Administrator prior to the proposed replacement with an estimate of the fixed capital cost of replacement (among other items, see 40 CFR 60.15(d)) and upon receipt, the Administrator will determine if the proposed replacement constitutes reconstruction.

Based on our experience from NSPS OOOO and NSPS OOOOa, the predominant type of storage vessel expected to be covered by the proposed NSPS are fixed roof storage vessels, and as part of the storage vessel affected facility, have limited depreciable components beyond the storage vessel itself (e.g., thief hatches and pressure relief devices). Because the EPA expects that each affected facility will undertake similar fixed capital cost replacements at storage vessel affected facilities, namely replacing one or more storage vessels, replacing thief hatches, and replacing pressure relief devices, we believe that it will serve as a burden reduction to industry to establish uniform criteria which constitute reconstruction. For a tank battery which consists of a single storage vessel, it may be possible that the cost of replacing the thief hatch, pressure relief device or other depreciable components could exceed 50 percent of the cost of an entirely new storage vessel, therefore the EPA is proposing that the provisions of 40 CFR 60.15 would apply. The EPA requests comment on this assumption that the costs of replacement of all depreciable components on a single storage vessel could exceed 50 percent of the cost of an entirely new storage vessel. For a tank battery which consists of more than a single storage vessel, we believe that the cost of replacing storage vessel components such as thief hatches and pressure relief devices, in comparison to the cost of constructing

an entirely new storage vessel affected facility, will not exceed 50 percent of the cost of constructing a comparable new storage vessel affected facility. Therefore, the EPA is proposing to simplify and streamline the reconstruction determination for tank batteries by defining reconstruction at a tank battery with more than a single storage vessel as replacement of 50 percent of the storage vessels in the tank battery. This defined reconstruction action will eliminate the need for the owner or operator to submit the notification in 40 CFR 60.15(d) and await the EPA's response under 40 CFR 60.15(e), before undertaking a replacement.

An important factor in determining whether over 50 percent of the storage vessels in an existing tank battery has been replaced is the time period for making such assessment. Consider the following scenario: an owner replaces one-third of the storage vessels in an existing tank battery and, shortly thereafter, replaces another third of the storage vessels in that tank battery. The owner has replaced 60 percent of the storage vessels in that tank battery in total; however, without specifying the time frame for assessing reconstruction, it is unclear whether the tank battery is "reconstructed" because over half of the storage vessels in the tank battery have been replaced, or the replacements are two separate programs and therefore should not be aggregated for purposes of determining reconstruction. For the reasons discussed in section IV.D and IV.E of this preamble, the EPA is proposing to interpret natural gas-drive pneumatic controller and pneumatic pump replacements to include all natural gas-driven pneumatic controllers and pneumatic pumps which commence replacement (but are not necessarily completed) within any 2-year period in determining whether the replacements constitute reconstruction. The EPA solicits comment on whether to similarly set a specific time period (or rolling time period) within which replaced storage vessels in an existing tank battery will be aggregated towards determining whether the 50 percent replacement threshold has been exceeded, and if so, whether a 2-year time frame or another time frame is appropriate for determining reconstruction to a tank battery with more than a single storage vessel.

Related to modifications, the EPA explained in the November 2021 proposal that actions occurring at a well site, such as refracturing a well or adding a new well that sends these liquids to the tank battery at the well

site or centralized production facility, would result in an increase in VOC and methane emissions based on an increase in volumetric throughput to the tank battery. See 86 FR 63199 (November 15, 2021). However, this does not always hold true for tank batteries located at a compressor stations or onshore natural gas processing plants. In the September 15, 2020, rule (see 85 FR 57404), the EPA finalized a different framework for determining the potential for VOC emissions from storage vessels located at compressor stations and onshore natural gas processing plants, based on comments received on the September 15, 2020, rule that storage vessels located at these types of facilities are designed to receive liquids from multiple well sites that may startup production over a longer period of time.²³³ To account for this future throughput to the storage vessels, compressor stations and natural gas processing plants use analysis based on the future maximum throughput capacity which is then used to obtain permits. Therefore, the EPA agrees that when a tank battery at a compressor station or onshore natural gas processing plant receives additional throughput which has already been accounted for in the design capacity of that tank battery and included as a legally and practically enforceable limit in a permit for the tank battery, that additional throughput does not result in an emission increase from the tank battery because those emissions have already been accounted for in the permit.

In summary, the EPA is proposing that a modification occurs to an existing tank battery located at a well site or centralized production facility when the tank battery receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput and the potential for VOC or methane emissions increases above the applicable thresholds. Separately, the EPA is proposing that a modification occurs to an existing tank battery located at a compressor station or onshore natural gas processing plant when the tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent determination for VOC or methane missions (e.g., permit) based on the design capacity of such tank battery. In addition, as proposed in November 2021, modification is also triggered by the following two events: (1) A storage vessel is added to an existing tank battery; and/or (2) one or

more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases.

One commenter expressed concerns that the change to a tank battery (in NSPS OOOOb) versus a single tank (in NSPS OOOOa) will cause confusion with the requirements of NSPS OOOOa because it creates a disconnect with how the previous NSPS for this source category applies the affected facility status to storage tanks. The commenter states that creating separate "classifications" within the NSPS based on dates of construction or modification will create additional burden when reviewing authorizations within the specified legislatively mandated time frames.²³⁴ The EPA discusses the interplay and effective dates between prior standards applicable to the Crude Oil and Natural Gas source category in sections III.B, III.C and III.D of this preamble. However, to address specific questions regarding applicability to storage vessels which may be subject to NSPS OOOO, NSPS OOOOa, or EG OOOOc, the EPA is providing a discussion of applicability for several anticipated scenarios which may be triggered by a potential modification action described above. For purposes of the scenarios below, the EPA is using the proposed definition of a tank battery, which includes a single storage vessel if only one storage vessel is present.

Scenario One—An existing tank battery has the potential for methane emissions greater than or equal to 20 tpy methane, therefore it is a designated facility for purposes of EG OOOOc. Subsequently, one of the proposed physical or operational changes in NSPS OOOOb at 40 CFR 60.5365b(e)(3)(ii) (i.e., adds a storage vessel to an existing tank battery; adds capacity to an existing tank battery; or receives additional fluids) occurs. In order to determine if modification has occurred to the existing tank battery, the owner or operator would calculate the potential for VOC and methane emissions in accordance with the proposed 40 CFR 60.5365b(e)(2). If the potential for either VOC or methane is above the proposed threshold, the tank battery is a modified storage vessel affected facility subject to NSPS OOOOb. If the potential for both VOC and methane is not above the threshold, the tank battery is not a modified (or reconstructed) storage vessel affected facility for purposes of NSPS OOOOb and remains a designated facility for purposes of EG OOOOc.

²³³ See Document ID No. EPA-HQ-OAR-2017-0473-1261.

²³⁴ See Document ID No. EPA-HQ-OAR-2021-0317-0763.

Scenario Two—An existing tank battery is not a designated facility under EG OOOOc (*i.e.*, the potential for methane emissions is less than 20 tpy). Like scenario 1, subsequently, one of the proposed physical or operational changes in NSPS OOOOb occurs and the owner or operator calculates the potential for VOC and methane emissions. If the potential for either VOC or methane emissions is above the proposed threshold, the tank battery is a modified storage vessel affected facility subject to NSPS OOOOb. If the potential for both VOC and methane is not above the proposed threshold, the tank battery is not a modified storage vessel affected facility for the purposes of NSPS OOOOb and is also not a designated facility under EG OOOOc.

Scenario Three—An existing storage vessel is a single storage vessel subject to either NSPS OOOO or NSPS OOOOa and is part of a tank battery. One of the proposed physical or operational changes in NSPS OOOOb occurs and the owner or operator calculates the potential for VOC and methane emissions from the entire tank battery. If the potential for either VOC or methane is above the threshold, the tank battery is a modified storage vessel affected facility subject to NSPS OOOOb, and the single storage vessel would continue to be subject to the applicable NSPS OOOO or NSPS OOOOa. However, where a facility is subject to multiple standards, the general practice is to streamline compliance by complying with the more stringent standard, which would in effect meet the less stringent standards. If the potential for both VOC and methane is not above the proposed threshold, the single storage vessel is not modified for the purposes of NSPS OOOOb and remains subject to NSPS OOOO or NSPS OOOOa.

Scenario Four—An existing storage vessel is a single storage vessel and is subject to either NSPS OOOO or NSPS OOOOa. The single storage vessel is not a designated facility under EG OOOOc because the potential for methane emissions is less than 20 tpy. One of the proposed physical or operational changes in NSPS OOOOb occurs and the owner or operator calculates the potential for VOC and methane emissions from the single storage vessel. If the potential for either VOC or methane is above the proposed threshold, the single tank is a tank battery which is a modified storage vessel affected facility subject to NSPS OOOOb, as well as NSPS OOOO or NSPS OOOOa. Where a facility is subject to multiple standards, the general practice is to streamline

compliance by complying with the more stringent standard, which would in effect meet the less stringent standards; however, streamlining may not be necessary here if the EPA finalized the proposed 95 percent reduction, which is the storage vessel standard in NSPS OOOO and NSPS OOOOa. If the potential for both VOC and methane is not above the threshold, the single tank is not modified for the purposes of NSPS OOOOb and remains subject to NSPS OOOO or NSPS OOOOa.

Removed From Service. Finally, in NSPS OOOO and NSPS OOOOa, the EPA includes provisions to address the status of storage vessel affected facilities which are physically isolated and disconnected from the process for purposes other than maintenance, which is referred to as “removed from service”.²³⁵ Those regulations also include a framework for determining the affected facility status of such storage vessels when they are “returned to service”, either by: (1) Being reconnected to the original source of liquids, (2) used to replace any storage vessel affected facility, or (3) installed in any location covered by the subpart and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water. The EPA is including these same provisions in the proposed NSPS OOOOb for situations where there is more than one storage vessel in a tank battery and the entire tank battery is removed from or returned to service. Additionally, the EPA is proposing language to address situations when only a portion of the tank battery is removed from, or returned to, service. Specifically, the EPA is proposing to require complete emptying and degassing of the entire tank battery, or the portion of the tank battery that is being removed, for it to be considered “removed from service”. Submission of a notification that these emptying and degassing requirements are met would also be required. Further, when a portion of a storage vessel affected facility is removed from service, in addition to the requirements above, the portion of the tank battery must be disconnected from the tank battery such that the portion is no longer manifolded to the tank battery by liquid or vapor transfer. When a tank battery is returned to service, it would retain the same applicability status that applied prior to removal from service. For tank batteries where only a portion of the tank battery is returned to service and it is reconnected to the original source of

liquids, it remains a storage vessel affected facility subject to the same requirements that applied before being removed from service. If a storage vessel is used to replace a storage vessel affected facility, or portion of a storage vessel affected facility, or used to expand a storage vessel affected facility, it assumes the affected facility status of the storage vessel affected facility being replaced or expanded.

Request for Additional Comment. In addition to the proposed changes or clarifications described above, the EPA is soliciting comment on including a requirement to equip thief hatches with alarms, automated systems to monitor for pressure changes, or use of automatically closing thief hatches. Commenters noted that open thief hatches and deteriorated seals around tank openings are significant emissions sources at tank batteries. The EPA is aware that some owners and operators utilize automated systems to alert when pressure changes occur that could signal an open thief hatch. Additionally, where automated systems are not available, there are alarms that could be utilized to alert (via audible alarm or remote notification to the nearest field office) that an unseated thief hatch is present.²³⁶ The EPA is soliciting information on the costs, operation, and feasibility of installing these automated systems, alarms, or the use of automatically closing thief hatches.

c. Summary of Proposed Requirements

In this proposed rule, owners and operators of storage vessel affected facilities must reduce methane and VOC emissions by 95 percent. Consistent with provisions of NSPS OOOO and NSPS OOOOa, the proposed rule also includes the option where if the owner or operator maintains the uncontrolled actual VOC emissions at less than 4 tpy and the actual methane emissions at less than 14 tpy as determined monthly for 12 consecutive months, controls are no longer required. Storage vessel affected facilities which use a control device to reduce emissions must equip each storage vessel in the tank battery with a cover and manifold all storage vessels in the tank battery such that all vapors are shared among the headspaces of the storage vessel affected facility. The tank battery must be equipped with a CVS which routes all emissions to a control device. The proposed rule would require that when using a flare, the flare must meet the requirements in 40 CFR 60.18, which the EPA is proposing to strengthen by including additional

²³⁵ See 78 FR 58435 (September 23, 2013), 79 FR 79022 (December 31, 2014), 80 FR 48262 (August 12, 2015), and 81 FR 35824 (June 3, 2016).

²³⁶ See Document ID No. EPA-HQ-OAR-2021-0317-0814.

requirements (as discussed in section IV.H of this preamble), and that monitoring, recordkeeping, and reporting be conducted to ensure that the flare is constantly achieving the required 95 percent reduction. More information on the control device monitoring and compliance provisions is provided in section IV.G of this preamble; additionally, notifications made through the super-emitter response program could help identify potential violations as provided in section IV.C of this preamble. If the storage vessel affected facility does not have flashing emissions and is not located at a well site or centralized production site, the owner or operator may use an internal or external floating roof to reduce emissions.

In each annual report, owners and operators would be required to identify each storage vessel affected facility that was constructed, modified, or reconstructed during the reporting period and must document the emission rates of both VOC and methane individually. The annual report must include deviations that occurred during the reporting period and information for control devices tested by the manufacturer or the date and results of the control device performance test for control devices not tested by the manufacturer. The report also must include the results of inspections of covers and CVS and the identification of storage vessel affected facilities (or portion of storage vessel affected facility) removed from service or returned to service. For storage vessel affected facilities which comply with the uncontrolled 4 tpy VOC limit or 14 tpy methane limit, the report must include changes which resulted in the source no longer complying with those limits and the dates that the source began to comply with the 95 percent reduction standard.

Required records include documentation of the methane and VOC emissions determination and methodology, records of deviations and duration, records for the number of consecutive days a skid-mounted or permanently mobile-mounted storage vessel is on the site, the latitude and longitude coordinates of each storage vessel affected facility, and records associated with a manufacturer tested control device. Required records also include records demonstrating continuous compliance including inlet gas flow rate, presence of pilot flame, operation with no visible emissions, maintenance and repair logs, manufacturer's operating instructions, and dates that each storage vessel affected facility (or portion of storage

vessel affected facility) is removed from service or returned to service. For storage vessel affected facilities which comply with the uncontrolled 4 tpy VOC or 14 tpy methane limit, records of changes which resulted in the source no longer complying with those limits and the dates that the source began to comply with the 95 percent reduction standard, including records of the methane and VOC determination and methodology. All associated records that demonstrate proper design and operation of the CVS, cover and control device also must be maintained (see section IV.G and IV.J. of this preamble).

2. EG OOOOc

The EPA is also proposing presumptive standards to reduce methane for existing storage vessel affected facilities in this action that remain unchanged from the November 2021 proposal and are similar to those proposed for NSPS OOOOb. Because the BSR for reducing VOC and methane emissions are the same, the proposed presumptive standard is to reduce methane emissions by 95 percent. Some commenters expressed that creating separate classifications (e.g., tank batteries vs single tanks) within the NSPS based on dates of construction or modification will create additional burden when reviewing authorizations within the specified legislatively mandated time frames. Another commenter requested that EPA clarify whether other individual storage vessels in an existing tank battery remain affected facilities under NSPS OOOO or NSPS OOOOa, as applicable, or become part of the modified tank battery under NSPS OOOOb.²³⁷ The EPA discusses the interplay and effective dates between prior standards applicable to the Crude Oil and Natural Gas source category in sections III.B, III.C and III.D of this preamble and provides example scenarios, which the EPA believes will provide guidance to regulators and the regulated community.

K. Covers and Closed Vent Systems

1. NSPS OOOOb

a. November 2021 Proposal

In the November 2021 proposal, the EPA proposed CVS requirements for certain affected facilities to ensure that emissions are captured and routed to a process or control device, dependent on the standard for the affected/designated facility. The affected/designated facilities for which the EPA proposed the use of a CVS were wells (oil wells

when routing associated gas to a control device), storage vessels, centrifugal compressors (wet seal), reciprocating compressors, pneumatic pumps, and process unit equipment affected/designated facilities. Additionally, for storage vessels using a control device to reduce emissions and centrifugal compressors with wet seals using a degassing system, the EPA proposed the use of covers to form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or the centrifugal compressor wet seal fluid degassing system. The cover requirements ensure that all emissions are captured from those emissions sources and routed through a CVS to a control device, or in the case of centrifugal compressors, to a control device or to a process. This section discusses the cover and CVS requirements for those affected/designated facilities that are located at well sites, centralized production facilities, and compressor stations. See the discussion on CVS in section IV.L of this preamble for covers and CVS located at natural gas processing plants.

In the November 2021 proposal, the EPA proposed that covers and CVS must be designed and operated with no detectable emissions (NDE). Further, the EPA proposed that where a CVS is used to route emissions from an affected facility, the owner or operator would demonstrate there are no detectable emissions from the covers and CVS through OGI or EPA Method 21 monitoring conducted during the fugitive emissions survey. Where emissions are detected, the emissions would be considered a violation of the NDE standard and thus a deviation,²³⁸ and corrective actions to complete all necessary repairs as soon as practicable would be required. The EPA also solicited comment on whether to include the option to continue utilizing monthly AVO surveys as demonstrations of NDE from a CVS associated with a pneumatic pump but did not propose that option specifically. We stated that because we anticipated that CVS associated with pneumatic pumps would be located at well sites subject to fugitive emissions monitoring, the monthly AVO option was not necessary. However, we solicited comment on whether there are circumstances where a CVS associated with a pneumatic pump is located at a well site not otherwise subject to

²³⁷ See Document ID No. EPA-HQ-OAR-2021-0317-0808.

²³⁸ A deviation includes any instance in which an affected source fails to meet any emission limit, operating limit, or work practice standard; a deviation suggests potential violation with the applicable performance standard.

fugitive emissions monitoring and where OGI (or EPA Method 21) would be an additional burden.

b. Changes From November 2021 Proposal

In this supplemental proposal, the EPA is proposing specific revisions to the requirements for CVS associated with the affected/designated facilities located at well sites, centralized production facilities, and compressor stations in the proposed NSPS OOOOb and EG OOOOc. First, the EPA is proposing the same design and operational requirements for all CVS when routing emissions to a control device or when routing emissions to a process, regardless of which affected/designated facility is using the CVS. These proposed standards would apply to wells (oil wells when routing associated gas to a control device), centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, and process unit equipment affected/designated facilities. See section IV.L of this preamble for additional discussion related to process unit equipment affected/designated facilities at onshore natural gas processing plants.

For these affected/designated facilities, the EPA is proposing the capture and routing of emissions through a CVS to a control device or process as part of the BSER, or an alternative to the BSER for specific situations such as technical infeasibility to apply BSER. The EPA finds that the demonstration of continuous compliance for these CVS should include the same robust standards to ensure the CVS are designed and operated to capture and route all emissions to the control device regardless of which affected/designated facility is using the CVS. The proposed standards for CVS include upfront engineering (Professional Engineer or in-house engineer) design analysis and certifications, an emissions limit that requires design and operation with no identifiable emissions, initial and periodic inspections of the CVS, and continuous monitoring of CVS bypass systems (unless equipped with a seal or closure mechanism). Therefore, in this proposal, the EPA is standardizing the design and operational requirements for CVS, regardless of their location or use (route to a control device or route to a process).

The EPA is proposing to change the design and operational requirements for CVS (except for those associated with self-contained pneumatic controllers) from operation with NDE to operation with no identifiable emissions. The

proposed change of terminology is not intended to change the stringency of the CVS requirements, which require that each CVS capture and route all gases, vapors, and fumes to a control device or a process, but it will clarify the design and operational standards, and the obligations on the part of the owner or operator if a leak is detected from the CVS during the inspections to ensure compliance with the no identifiable emissions standard.

Based on comments received on the November 2021 proposal, there appears to be confusion whether the proposed NDE standard would be an emissions limit or a work practice standard. For example, one commenter²³⁹ stated that as written, the NDE standard would be a work practice standard because “[a]s with all other fugitive emissions components, detection of a leak (in this case, defined as detectable emissions) through routine LDAR monitoring triggers the obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented.” This interpretation of the standard is not correct. In fact, CVS must be designed and operated to route all gases, vapors, and fumes to a control device or to a process, which is defined as an emission limit of NDE. The corrective actions (in the form of the repair provisions) are provided to ensure that owners and operators bring the CVS back into compliance with the NDE emission limit as quickly as possible.

Past efforts in NSPS OOOO and NSPS OOOOa to apply an NDE standard as an emission limitation, while still allowing repair, delay of repair or exceptions for unsafe and difficult to inspect equipment, may appear to condone a “grace period” during which compliance with an emissions limit is not required. Because the NDE standard in NSPS OOOO and NSPS OOOOa was established as an emissions limit, operation in exceedance of that limit is a deviation,²⁴⁰ even if the repair provisions are followed.

Similarly, the EPA is proposing an emissions limit for covers and CVS in this supplemental proposal for NSPS OOOOb and EG OOOOc. However, NDE is a term closely linked with EPA Method 21, and is defined based on an instrument reading in units of ppmv. Because the EPA is proposing

compliance inspections for covers and CVS using optical gas imaging and AVO, no instrument reading in ppmv is available. Therefore, the EPA is proposing the design and operational standard as an emissions limit of no identifiable emissions, which is more appropriate for the methods of detection required.

To ensure compliance with the no identifiable emissions design and operational standard for covers and CVS located at well sites, centralized production facilities, and compressor stations, the EPA is proposing that owners or operators would conduct initial and quarterly OGI inspections (except for the Alaska North Slope which is annually). Any identified emissions would be a violation of this emissions limit and would be subject to repair with a first attempt completed within 5 days and final repair within 30 days of identification. If the owner or operator is using the EPA Method 21 alternative for their fugitive emissions components, then any instrument reading greater than 500 ppmv above background is considered identified emissions, would be a potential violation of the no identifiable emissions standard, and would require repair within the same 5- and 30-day timeframe to bring the CVS back into compliance.

The EPA is also proposing to require AVO inspections for CVS and covers located at well sites, centralized production facilities and compressor stations. The EPA is proposing that AVO inspections of CVS and covers must occur at the same frequency specified for fugitive emissions components affected facilities located at the same type of site. As discussed in section IV.A.1.a.ii of this preamble, the EPA is proposing that CVS and covers located at a well site, centralized production facility, or compressor station site, which are not associated with a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, or storage vessel affected facility, are fugitive emissions components and subject to those standards, which include periodic OGI (or EPA Method 21 as an alternative) and monthly or bimonthly AVO inspections. Because we are aligning the CVS associated with well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, or storage vessel affected facilities inspections with the frequency of inspections under the fugitives program, there should be no additional cost associated with conducting these AVO inspections of CVS that are not fugitive emissions

²³⁹ See Document ID No. EPA-HQ-OAR-2021-0317-0808.

²⁴⁰ A deviation signals possible violation with the performance standard for an affected facility because compliance is no longer demonstrated due to such exceedance.

components at the same time and at the same place, and we believe that identifying and repairing such leaks is consistent with the proposed requirement at 40 CFR 60.5370b(b) in a manner consistent with good air pollution control practice for minimizing emissions. See section IV.A of this preamble for a full discussion of the fugitive emissions requirements.

The EPA did not receive comment in response to our request regarding the burden of OGI (or EPA Method 21) monitoring for CVS associated with pneumatic pumps at well sites. Therefore, the EPA is not proposing separate standards for those CVS associated with pneumatic pumps and is proposing consistent standards for all CVS associated with affected/designated facilities under NSPS OOOOb or EG OOOOc.

As discussed in section IV.D of this preamble, the EPA is proposing that pneumatic controllers may comply with the zero-emission methane and VOC standard for pneumatic controllers by installing a self-contained pneumatic controller, which is a natural gas-driven controller designed so that there are no emissions to the atmosphere. These controllers are designated as “no identifiable emissions” in the proposed rule. Because these are designed to contain all gases, vapors, or fumes from the controller, the EPA finds it appropriate to apply the same continuous compliance requirements to self-contained controllers as those for covers and CVS described in this section. That is, the EPA is proposing to require the operation of self-contained pneumatic controllers with no identifiable emissions, as demonstrated through quarterly OGI monitoring. Any emissions identified would be a violation of the zero emissions standard. The repair requirements described for CVS would also apply to bring the self-contained pneumatic controller back into compliance with the zero emissions standard.

As discussed in section IV.B of this preamble, the EPA also is proposing provisions for the use of alternative test methods that employ alternative periodic screening technologies or continuous monitoring systems. The EPA is proposing to allow use of alternative test methods to replace the use of OGI for demonstrating continuous compliance of the no identifiable emissions standard for covers and CVS. The EPA recognizes that the allowable minimum detection thresholds of the screening technologies used in the alternative periodic screening approach may not be capable of identifying all of the potential

emissions from these sources; however we find that well designed, maintained, and certified covers and CVS systems are not prone to leaks, and the majority of emission events from these systems can be attributed to short-term operational events or malfunctions that would be at a level easily identified by screening technology meeting the allowable minimum detection thresholds. The EPA considers the use of more frequent surveys (monthly to quarterly) using approved screening technologies and either annual (if required based on minimum detection threshold and frequency) or OGI surveys resulting from emissions detected during screening would ensure equivalent compliance assurance of the no identifiable emissions standard as the quarterly OGI surveys paired with monthly or bimonthly AVO inspections. The EPA solicits comments on the use of the alternative periodic screening approach as an alternative compliance assurance for covers and CVS associated with affected/designated facilities, and we solicit comments that the minimum detection thresholds summarized in Tables 20 and 21 (section IV.B of this preamble) are suitable for this purpose.

c. Summary of Proposed Requirements

The EPA is proposing standards which apply to CVS at a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, or process unit equipment affected/designated facility. The EPA also is proposing standards for covers at a centrifugal compressor and storage vessel affected/designated facility. This summary is limited to covers and CVS located at well sites, centralized production facilities, and compressor stations. Covers and CVS located at natural gas processing plants (process unit equipment affected/designated facilities) are discussed in section IV.L of this preamble.

Each CVS must be designed and operated to capture and route all gases, vapors, and fumes to a process or to a control device and comply with an emissions limit of no identifiable emissions. Initial and continuous compliance of the no identifiable emissions standard would be demonstrated through OGI monitoring and AVO inspections conducted at the same frequency as the fugitive emissions monitoring for the type of site. Specifically, for the well sites and centralized production facilities where a CVS is present, quarterly OGI and bimonthly AVO would be required; for compressor stations, quarterly OGI and monthly AVO would be required. If the

CVS is equipped with a bypass, the bypass must include a flow monitor and sound an alarm to alert personnel that a bypass is being diverted to the atmosphere, or it must be equipped with a car-seal or lock-and-key configuration to ensure the valve remains in a non-diverting position. To ensure proper design, an assessment must be conducted and certified by a qualified professional engineer or in-house engineer. Covers must form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or over the centrifugal compressor wet seal fluid degassing system and each cover opening shall be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening.

Each CVS must be inspected using OGI or EPA Method 21 to ensure that the CVS operates with no identifiable emissions. Annual visual inspections to check for defects, such as cracks, holes, or gaps) must be conducted and monthly (compressor stations) or bimonthly (well sites and centralized production facilities) AVO inspections for leaks must be conducted would be a potential violation of the no identifiable emissions standard. Further, any leak detected would be subject to repair, with a first attempt at repair at five days and final repair within 30 days. While awaiting final repair, covers must have a gasket-compatible grease applied to improve the seal. Delay of repair is allowed where the repair is infeasible without a shutdown, or it is determined that immediate repair would result in emissions greater than delaying repair. In all instances, repairs must be completed by the end of the next shutdown. Unsafe to inspect and difficult to inspect parts of the closed vent system may be designated as such but must be inspected according to a plan as frequently as possible, or every five years, respectively.

Records of CVS and cover inspections, CVS bypass monitoring, and CVS design and certifications must be maintained. The CVS certification must be submitted in the initial annual report. Because the requirements for CVS and covers have been aligned for all affected facilities which use a CVS or cover, a new reporting section has been created to contain the similar requirements. Recordkeeping sections for CVS inspections, covers, bypass monitoring and CVS design assessment also have been created which are applicable to all sources which use CVS and covers. This will streamline

compliance as all affected facilities using the CVS and cover requirements of the rule will be subject to the same reporting and recordkeeping requirements.

L. Equipment Leaks at Natural Gas Processing Plants

1. NSPS OOOOb

a. November 2021 Proposal

In the November 2021 proposal, the EPA proposed new standards of performance for equipment leaks at natural gas processing plants by revising the equipment leak standards for onshore natural gas plants to apply more readily to process unit equipment that has the potential to emit methane even though not “in VOC service.” The EPA also proposed appendix K to provide a standard method for OGI monitoring, which allowed the EPA to consider a wider range of LDAR programs when evaluating BSER for equipment leaks at onshore natural gas processing plants. Specifically, the EPA proposed to require bimonthly OGI monitoring of valves, pumps, and connectors that have the potential to emit methane and VOC following the protocol specified in the proposed appendix K. As an alternative, the EPA proposed to allow for monthly monitoring of pumps, quarterly monitoring of valves, and annual monitoring of connectors that have the potential to emit methane and VOC following EPA Method 21, with a leak defined as any instrument reading above 2,000 ppm for pumps or 500 ppm for valves and connectors. The EPA utilized a Monte Carlo analysis to compare these programs and determined that they achieved equivalent emissions reductions. See 86 FR 63232 (November 15, 2021) for additional information. The November 2021 proposal also included requirements for a “first attempt at repair” for all identified leaks within five days of detection, as well as final repair completed within 15 days of detection (except when delay would be allowed).

Finally, in the November 2021 proposal, the EPA requested comments on certain topics. First, we requested comment on ways to streamline approval of alternative LDAR programs using remote sensing techniques, sensor networks, or other alternatives for equipment leaks at onshore natural gas processing plants, including whether providing an emission reduction target and equipment leak modeling tool to simulate LDAR under similar “ideal” program implementation conditions might facilitate future equivalency determinations. Second, we requested

comment on: (1) Adding a requirement of OGI monitoring (or EPA Method 21 monitoring for sources opting for the alternative) on open-ended valves or lines equipped with closure devices to ensure no emissions are going to the atmosphere (e.g., to ensure the cap seals the open end); and (2) allowing the use of OGI monitoring according to the proposed appendix K, to demonstrate compliance with the no detectable emissions requirements (in lieu of EPA Method 21) such as those for CVS at onshore natural gas processing plants.

b. Changes From November 2021 Proposal

In this supplemental proposal, the EPA is proposing specific requirements for the individual process unit equipment type included in the LDAR program at onshore natural gas processing plants. This section describes those specific requirements for pressure relief devices, open-ended valves or lines, and CVS.

Pressure Relief Devices. Consistent with the November 2021 proposal, the EPA is proposing to require bimonthly OGI monitoring (or quarterly EPA Method 21 monitoring, if the alternative is used) as well as monitoring of each pressure relief device within 5 calendar days after each pressure release to detect leaks using either OGI or EPA Method 21. A leak is detected if any emissions are observed using OGI, or if an instrument reading of 500 ppm or greater is provided using EPA Method 21. The EPA is proposing this requirement instead of requiring a NDE demonstration (which is also required in NSPS OOOOa) because after reviewing the record to NSPS KKK (the original LDAR requirements for onshore natural gas processing plants), it was clear that the basis for the standards for pressure relief devices was a routine LDAR program.²⁴¹ Because we have determined that OGI is BSER for equipment leaks at onshore natural gas processing plants, it is appropriate to require bimonthly OGI monitoring for this process unit equipment. In addition to this bimonthly OGI monitoring requirement, the EPA is also proposing to require OGI monitoring of each pressure relief device after each pressure release, as it is important to ensure the pressure relief device has resealed and is not allowing emissions to vent to the atmosphere. The EPA is soliciting comment on this change from a no detectable emissions standard to a bimonthly monitoring requirement. Where the EPA Method 21 option is

used, we are proposing quarterly monitoring of the pressure relief device in addition of monitoring after each pressure relief. A leak is defined as an instrument reading of 500 ppm or greater when using EPA Method 21.

Open-Ended Valves or Lines. For open-ended valves or lines, the EPA is proposing to require closure devices to seal the open end, consistent with the requirements in NSPS OOOOa. Consistent with the November 2021 proposal, the proposed regulatory text would require this equipment standard (i.e., cap, blind flange, plug, or a second valve) for open-ended valves and lines. The EPA solicited comment on whether to require bimonthly OGI monitoring for open-ended valves and lines in the November 2021 proposal. We are not proposing to require routine periodic monitoring for open-ended valves or lines. The primary control requirement for open-ended valves or lines is a closure device (i.e., caps, blind flanges, plugs, or a second valve) and this standard is designed to achieve nearly 100 percent emission reductions. While it is possible that leaks past the closure device could occur, the EPA does not believe it would be cost-effective to require a full LDAR program for each open-ended valve or line, and has previously found this type of requirement not cost-effective for this type of facility.²⁴² However, the EPA recognizes that there are opportunities to identify when there is a leak past the closure device as part of daily operating duties or required OGI surveys for other process unit equipment. Therefore, the EPA is proposing a requirement to complete repairs on an open-ended valve or line so that the closure device seals the open end of the valve or line when emissions are identified through any means. The EPA notes that repairs for this type of leak are generally straightforward (e.g., install new plug or cap) and cost-effective to complete. Further, the repair is necessary to comply with the general duty provisions of 40 CFR 60.5370b(b).

Closed Vent Systems. In NSPS OOOO and NSPS OOOOa, the EPA relied on separate CVS requirements for ones located at an onshore natural gas processing facility than those requirements for CVS used for other purposes in NSPS OOOO and NSPS OOOOa. In this proposal, the EPA is standardizing the requirements for CVS, as described in section IV.K of this preamble, with one difference.

For CVS associated with process unit equipment affected facilities that are

²⁴¹ See 49 FR 2645 (January 24, 1984) and EPA–450/3–82–024b.

²⁴² See Document ID Nos. EPA–HQ–OAR–2010–0505–0045 and EPA–HQ–OAR–2010–0505–7631.

used to route emissions from leaking equipment to a control device, the EPA is proposing a requirement to monitor the CVS at the same frequency (*i.e.*, bimonthly OGI in accordance with appendix K or quarterly EPA Method 21) as other equipment in the process unit and to repair any leaks identified during the routine monitoring. Additionally, when leaks are identified as part of daily operating duties by any means of detection, we are proposing to require repairs in order to be consistent with the good air pollution control practices for minimizing emissions specified in 40 CFR 60.5370b(b). We believe it is most efficient and cost effective to monitor the CVS at the same frequency and according to the same methodology as other equipment in the process unit equipment affected facility (*i.e.*, bimonthly OGI in accordance with appendix K or quarterly with EPA Method 21) and it is reasonable and prudent to require any leaks identified to be repaired.

These proposed standards differ from our November 2021 proposal, which maintained EPA Method 21 inspections for CVS associated with process unit equipment, consistent with what is required in NSPS OOOO and NSPS OOOOa. Both NSPS OOOO and NSPS OOOOa require initial monitoring of a CVS used to comply with the equipment leak standards using EPA Method 21 followed by annual monitoring using visual inspections for defects (if constructed of hard piping) or annually using EPA visual inspections for defects and EPA Method 21 inspections (if constructed of ductwork). In this supplemental proposal, the EPA is proposing to allow initial monitoring using OGI in accordance with appendix K (or EPA Method 21 as an alternative) and annual visual methods for CVS where each joint, seam, or other connection is permanently or semi-permanently sealed (hard piping). This approach for initial instrument monitoring and annual visual monitoring for defects is consistent with the hard-piping requirements in NSPS OOOO and NSPS OOOOa and is also consistent with the requirements for other affected facilities which use a hard-piped CVS to route to a control device.

Potential To Emit Methane or VOC. Consistent with the November 2021 proposal, the EPA is proposing to apply the LDAR standards to process unit equipment that has the potential to emit methane or VOC.²⁴³ Further, the EPA is proposing that each piece of equipment is presumed to have the potential to

emit methane or VOC unless an owner or operator demonstrates that the piece of equipment does not have the potential to emit methane or VOC. For a piece of equipment to be considered not to have the potential to emit methane or VOC, the owner or operator would need to demonstrate that the process fluids in contact with the process unit equipment do not contain either methane or VOC. Commenters²⁴⁴ suggested that the EPA maintain the 10 percent by weight VOC concentration threshold and add a one percent by weight methane concentration threshold so as to exclude ethane product streams, produced water streams, and wastewater streams. However, no additional data or analyses were provided to demonstrate that a threshold of one percent by weight methane would be appropriate. Further, recent studies indicate that produced water and wastewater streams can be significant sources of VOC and/or methane emissions.²⁴⁵ Therefore, the EPA maintains that a definition based on the potential to emit VOC or methane is appropriate to determine which process unit equipment must be monitored and repaired.

Repair Requirements. In this supplemental proposal, the EPA is proposing a definition of “first attempt at repair” consistent with the November 2021 proposal, which means an action taken for the purpose of stopping or reducing fugitive emissions to the atmosphere. First attempts at repair include, but are not limited to, the following practices where practicable and appropriate: tightening bonnet bolts; replacing bonnet bolts; tightening packing gland nuts; or injecting lubricant into lubricated packing. Further, we are proposing a definition of “repaired,” specific to process unit equipment affected facilities, meaning that equipment is adjusted, or otherwise altered, in order to eliminate a leak, and is re-monitored to verify that emissions from the equipment are below the applicable leak definition. Pumps subject to weekly visual inspections which are designated as leaking and repaired are not subject to remonitoring. We are adding these definitions to

clarify the requirements for leak repair associated with process unit equipment. The EPA is not proposing to require replacement of leaking equipment with low-emissions (“low-e”) valves or valve packing or require drill-and-tap with a low-e injectable because it is not appropriate for all valve repairs.

However, because this low-e equipment, which meets the specifications of API 622 or 624, generally will include a manufacturer written warranty that it will not emit fugitive emissions at a concentration greater than 100 ppm within the first 5 years, we believe that they can be a viable option for repair in some instances, as demonstrated by the remonitoring requirements in the rule.

As described in the November 2021 proposal, the EPA is proposing to allow for delay of repair for leaks identified with OGI (or EPA Method 21), where it is technically infeasible to complete repairs within 15 days without a process unit shutdown. Generally, a process unit shutdown will generate more emissions than allowing the leak to continue; therefore, we are proposing to retain this delay of repair provision.

Alternative Use of EPA Method 21. As discussed in the November 2021 proposal, the EPA is proposing to allow the use of EPA Method 21 as an alternative to the required OGI monitoring. However, unlike NSPS OOOO and NSPS OOOOa, the EPA is not cross-referencing the requirements in NSPS VVa and is instead proposing regulatory text which incorporates the requirements directly into 40 CFR 60.5401b, with conforming changes consistent with the OGI standards, as described above for pressure relief devices, CVS, and repairs.

c. Summary of Proposed Requirements.

The proposed standards will apply to the “process unit equipment” affected facility and will require that each piece of equipment that has the potential to emit methane or VOC conduct bimonthly (*i.e.*, once every other month) OGI monitoring in accordance with appendix K to detect equipment leaks from pumps, valves, connectors, pressure relief devices, and CVS. As an alternative to the bimonthly OGI monitoring, EPA Method 21 may be used to detect leaks from the same equipment as frequencies specific to the process unit equipment type (*e.g.*, monthly for pumps, quarterly for valves).

Furthermore, this proposed rule requires that any leaks identified by AVO, or other detection methods from any equipment in any service, including open-ended valves or lines, must be repaired. The proposed rule includes

²⁴⁴ See Document ID No. EPA-HQ-OAR-2021-0317-0808.

²⁴⁵ “Measurement of Produced Water Air Emissions from Crude Oil and Natural Gas Operations.” Final Report. California Air Resources Board. May 2020. Available at: https://www.epa.gov/sites/default/files/2021-04/documents/2021_ghgi_update_-_water.pdf.

And “Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2019: Updates for Produced Water Emissions.” April 2021. Available at: https://www.epa.gov/sites/default/files/2021-04/documents/2021_ghgi_update_-_water.pdf.

²⁴³ See 86 FR 63182 (November 15, 2021).

requirements for a first attempt at repair for all leaks identified within five days of detection, and final repair completed within 15 days of detection (unless the delay or 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.

In addition to the monitoring and repair requirements summarized above, this proposal includes requirements for specific types of equipment. First, the EPA is proposing that each open-ended valve or line must be equipped with a closure device (*i.e.*, cap, blind flange, plug, or a second valve) that seals the open end at all times except during operations which require process fluid flow through the open-ended valve or line. Next, CVS used to comply with the standards for process unit equipment must be monitored bimonthly using OGI (or quarterly using EPA Method 21 if the alternative is used). We are also proposing that control devices used to comply with the equipment leak provisions must comply with the requirements described in section IV.G of this preamble.

The EPA is proposing that pressure relief devices must be monitored bimonthly using OGI (or quarterly using EPA Method 21 if the alternative is used) and five days after a pressure release to ensure the device has reseated after a pressure release. The proposed rule allows exceptions to the five-day post-pressure release monitoring requirement for pressure relief devices that are located in a nonfractionating plant (instead, the pressure relief device may be monitored after a pressure release the next time monitoring personnel are onsite, but in no event may it be allowed to operate for more than 30 calendar days after a pressure release without monitoring) or that are routed to a process, fuel gas system or control device.

This proposed rule requires AVO, or other detection methodologies for pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service and requires repair where a leak is found using any of those methods.

Reporting would be required semiannually, which differs from the reporting for other affected facilities in NSPS OOOOb. In the initial semiannual report, the proposed rule will require the owner or operator to identify: each process unit associated with the process unit equipment affected facility; the number of each type of equipment subject to the monitoring requirements; for each month of the reporting period, the number of leaking equipment for

which leaks were identified, the number of leaking equipment for which leaks were not repaired and the facts that explain each delay of repair; and dates of process unit shutdowns.

In subsequent semiannual reports, owners and operators would be required to report the name of each process unit associated with the process unit equipment affected facility; any changes to the process unit identification or the number or type of equipment subject to the monitoring requirements; for each month of the reporting period, the number of leaking equipment for which leaks were identified, the number of leaking equipment for which leaks were not repaired and the facts that explain each delay of repair; and dates of process unit shutdowns.

Required records in the proposed rule include inspection records consisting of equipment identification, date and start and end times of the monitoring inspection, inspector name, leak determination method, monitoring instrument identification, type of equipment monitored, process unit identification, appendix K records (if applicable), EPA Method 21 instrument readings and calibration results (if applicable) and, for visual inspections, the date, name of inspector and result of inspection. For each leak detected, the proposed rule requires reporting of the instrument and operator identification (or record of AVO method, where applicable), the date the leak was detected, the date and repair method applied for first attempts at repair, indication of whether the leak is still detected, and the date of successful repair, which includes results of a resurvey to verify repair. For each delay of repair, the proposed rule requires that the equipment is identified as "repair delayed" along with the reason for the delay, the signature of the certifying official, and the dates of process unit shutdowns which occurred while the equipment is unrepaired. Additionally, the proposed rule requires records of equipment designated for no detectable emissions; the identification of valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation stating why it is unsafe-to-monitor, and the plan for monitoring that equipment; a list of identification numbers for valves that are designated as difficult-to-monitor, an explanation stating why it is difficult-to-monitor, and the schedule for monitoring each valve; a list of identification numbers for equipment that is in vacuum service and a list of identification numbers for equipment designated as having the potential to emit methane or VOC less than 300 hr/yr. Finally, for CVS and

control devices used to control emissions from process unit equipment affected facilities, the reports and records that demonstrate proper design and operation of the control device also must be maintained (see sections IV.G and IV.J. of this preamble).

2. EG OOOOc

The application of an LDAR program at an existing source is the same as at a new source because there is no need to retrofit equipment at the site to achieve compliance with the work practice standard. The cost effectiveness for implementing a bimonthly OGI LDAR program for all process unit equipment that has the potential to emit methane is approximately \$850/ton methane reduced. As explained in section III.E of this preamble, the cost effectiveness of this OGI monitoring option is within the range of costs we believe to be reasonable for methane reductions in this rule. Therefore, we consider a bimonthly OGI LDAR program following appendix K that includes all process unit equipment that have the potential to emit methane to be BSER for existing sources. The presumptive standards that are proposed in this action are the same as those described above for NSPS OOOOb.

M. Sweetening Units

The EPA proposed to retain the standards found in NSPS OOOO and NSPS OOOOa for reducing SO₂ emissions from sweetening units in the November 15, 2021, proposal. The EPA is proposing regulatory text at 40 CFR 60.5405b through 60.5408b reflect the standards of performance as proposed in the November 15, 2021, proposal. To clarify and align compliance requirements (including recordkeeping and reporting) for sweetening units with those of other affected facilities, the EPA is proposing specific language at 40 CFR 60.5405b which "points" the owner or operator to the appropriate compliance requirement sections (*i.e.*, those containing initial compliance, continuous compliance, recordkeeping and reporting) and is proposing to enumerate the initial compliance requirements (of the unchanged standards) in section 40 CFR 60.5410b(i) and the continuous compliance requirements (of the unchanged standards) at 40 CFR 60.5415b(k).

N. Recordkeeping and Reporting

In the November 2021 proposal, the EPA proposed to require electronic reporting of performance test reports, annual reports, and semiannual reports through the Compliance and Emissions

Data Reporting Interface (CEDRI). CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>). As noted in that proposal, a description of the electronic data submission process is provided in the memorandum Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules, available in the docket for this action. The EPA also proposed to allow owners and operators the ability to seek extensions for electronic reporting for circumstances beyond the control of the facility (*i.e.*, for a possible outage in CDX or CEDRI or for a *force majeure* event).

In this action, the EPA is not proposing any changes from what was proposed in the November 2021 proposal. As noted in the November 2021 proposal, owners and operators would be required to use the appropriate spreadsheet template to submit information to CEDRI for annual and semiannual reports. A draft version of the proposed templates for these reports is included in the docket for this action.²⁴⁶ The EPA specifically requests comment on the content, layout, and overall design of the templates.

V. Supplemental Proposal for State, Tribal, and Federal Plan Development for Existing Sources

A. Overview

In the November 2021 proposal, the EPA proposed EG for states to follow in developing their plans to reduce emissions of GHGs (in the form of limitations on methane) from designated facilities within the Crude Oil and Natural Gas source category.²⁴⁷ That proposal provided a general overview of the state planning process triggered by the EPA's finalization of EG under CAA section 111(d), the EG process and proposed state plan requirements in more detail, and solicited comment on various issues related to the EG. In this supplemental proposal, the EPA is proposing some adjustments from the November 2021 proposal, and additional requirements to provide states with information needed for purposes of state plan development. In the following sections, in the same six-part ordering as the November 2021 proposal, we summarize and rationalize the updated and new proposed requirements. The EPA is not soliciting

additional comment on aspects of the November 2021 proposed EG that are not substantively addressed or changed in this supplemental proposal.

First, we discuss changes to the proposed requirements for establishing standards of performance in state plans in response to a finalized EG. Second, we discuss changes to the proposed components of an approvable state plan submission. Third, we discuss the proposed timing for state plan submissions, and changes to the proposed timeline for designated facilities to come into final compliance with the state plan. While this section describes the requirements of the implementing regulations under 40 CFR part 60, subpart Ba, proposes requirements for states in the context of this EG, and solicits comments in the context of this EG, nothing in this proposal is intended to reopen the implementing regulations themselves for comment.

B. Establishing Standards of Performance in State Plans

After the EPA establishes the BSER in the final EG, as described in preamble section XII of the November 2021 proposal and preamble section IV of this supplemental proposal, each state that includes a designated facility must develop, adopt, and submit to the EPA its state plan under CAA section 111(d). Under the Tribal Authority Rule (TAR) adopted by the EPA, tribes may seek authority to implement a plan under CAA section 111(d) in a manner similar to a state. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment in a manner similar to a state for purposes of developing a tribal implementation plan (TIP) implementing the EG. The November 2021 proposal included proposed requirements regarding two key aspects of implementation: establishing standards of performance for designated facilities, and providing measures that implement and enforce such standards. The November 2021 proposal additionally discussed and solicited comments on accommodating state programs, remaining useful life and other factors (RULOF), emissions inventories, and meaningful engagement. In the subsections below, the EPA proposes updates to certain presumptive standards included in the November 2021 proposal, and further proposes requirements related to leveraging state programs, RULOF, certain implementation and enforcement measures, emissions inventories, and meaningful engagement with pertinent stakeholders. The EPA believes these proposed requirements,

in addition to those described in the November 2021 proposal, will be necessary for states to prepare their CAA section 111(d) state plans. The EPA is not reopening for comment any aspect described in the November 2021 proposal that the EPA is not proposing to substantively address or update in this supplemental proposal.

The November 2021 proposal included proposed requirements regarding two key aspects of implementation: establishing standards of performance for designated facilities and providing measures that implement and enforce such standards. The November 2021 proposal additionally discussed and solicited comments on accommodating state programs, RULOF, emissions inventories, and meaningful engagement. In the following subsections, the EPA proposes updates to certain presumptive standards included in the November 2021 proposal, and further proposes requirements related to leveraging state programs, RULOF, certain implementation and enforcement measures, emissions inventories, and meaningful engagement with pertinent stakeholders. The EPA believes these proposed requirements, in addition to those described in the November 2021 proposal, will be necessary for states to prepare their CAA section 111(d) state plans. The EPA is not reopening for comment any aspect described in the November 2021 proposal that the EPA is not proposing to substantively address or update in this supplemental proposal.

1. Establish Standards of Performance for Designated Facilities

In the November 2021 proposal, the EPA proposed the degree of emission limitation achievable through application of the BSER in the form of presumptive standards for designated facilities.²⁴⁸ The EPA described that there is a fundamental requirement under CAA section 111(d) that a state plan's standards of performance reflect the presumptive standard, which derives from the definition of "standard of performance" in CAA section 111(a)(1). The EPA is updating Tables 35 and 36 to reflect the updated presumptive standards in this supplemental proposal.

²⁴⁶ See Part 60 Subpart OOOOb 60.5420b(b) Annual Report.xlsm and Part 60 Subpart OOOOb 60.5422b(b) Semiannual Report.xlsx, available in the docket for this action.

²⁴⁷ See 86 FR 63110 (November 15, 2021).

²⁴⁸ As described in section IV.C of this preamble, the EPA is proposing a super-emitter response program under the statutory rationale that super-emitters are a designated facility. The EPA is also proposing the program under a second rationale that the super-emitter response program constitutes work practice standards for certain sources and compliance assurance measures for other sources. Under either rationale, state plans are required to

TABLE 35—SUMMARY OF PROPOSED EG SUBPART OOOOc PRESUMPTIVE NUMERICAL STANDARDS

Designated facility	Proposed presumptive numerical standards in the draft emissions guidelines for GHGs
Storage Vessels: Tank Battery with PTE of 20 tpy or More of Methane ...	95 percent reduction of methane.
Pneumatic Controllers: Natural gas-driven that Vent to the Atmosphere ...	Methane emission rate of zero.
Pneumatic Pumps	Methane emission rate of zero.
Wet Seal Centrifugal Compressors (except for those located at well sites).	Volumetric flow rate of 3 scfm.
Dry Seal Centrifugal Compressors (except for those located at well sites)	Volumetric flow rate of 3 scfm.
Reciprocating Compressors (except for those located at well sites)	Volumetric flow rate of 2 scfm.

TABLE 36—SUMMARY OF PROPOSED EG SUBPART OOOOc PRESUMPTIVE NON-NUMERICAL STANDARDS

Designated facility	Proposed presumptive non-numerical standards in the draft emissions guidelines for GHGs
Super-Emitters	Root cause analysis and corrective action following notification by an EPA-approved entity or regulatory authority of a super-emitter emissions event. ²⁴⁹
Fugitive Emissions: Single Wellhead Only Well Sites and Small Well Sites.	Quarterly AVO inspections. Repair for indications of potential leaks within 15 days of inspection. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Multi-wellhead Only Well Sites (2 or more wellheads)	Quarterly AVO inspections. Repair for indications of potential leaks within 15 days of inspection. Semiannual OGI monitoring (Optional semiannual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Well Sites and Centralized Production Facilities	Well sites with specified major production and processing equipment: Quarterly OGI monitoring. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Compressor Stations	Monthly AVO monitoring. AND Quarterly OGI monitoring. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations on Alaska North Slope.	Annual OGI monitoring. (Optional annual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations	(Optional) Alternative periodic screening with advanced measurement technology instead of OGI monitoring.
Fugitive Emissions: Well Sites and Compressor Stations	(Optional) Alternative continuous monitoring system instead of OGI monitoring.
Pneumatic Controllers: Alaska (at sites where onsite power is not available—continuous bleed natural gas-driven).	Natural gas bleed rate no greater than 6 scfh.
Pneumatic Controllers: Alaska (at sites where onsite power is not available—intermittent natural gas-driven).	OGI monitoring and repair of emissions from controller malfunctions.
Gas Well Liquids Unloading	Perform liquids unloading with zero methane or VOC emissions. If this is not feasible for safety or technical reasons, employ best management practices to minimize venting of emissions to the maximum extent possible.
Equipment Leaks at Natural Gas Processing Plants	LDAR with OGI following procedures in appendix K.

adopt the super-emitter response program either as presumptive standards or as measures that provide for the implementation and enforcement of such standards.

TABLE 36—SUMMARY OF PROPOSED EG SUBPART OOOOc PRESUMPTIVE NON-NUMERICAL STANDARDS—Continued

Designated facility	Proposed presumptive non-numerical standards in the draft emissions guidelines for GHGs
Oil Wells with Associated Gas	Route associated gas to a sales line. If access to a sales line is not available, the gas can be used as an onsite fuel source or used for another useful purpose that a purchased fuel or raw material would serve. If demonstrated that a sales line and beneficial uses are not technically feasible, the gas can be routed to a flare or other control device that achieves at least 95 percent reduction in methane emissions.

2. Leveraging State Programs

a. Overview

In the November 2021 proposal, the EPA acknowledged that many states have programs they may want to leverage for purposes of satisfying their CAA section 111(d) state plan obligations (86 FR 63252; November 21, 2021). The EPA proposed that a state plan which relies on a state program must establish standards of performance that are in the same form as the presumptive standards. The EPA further solicited comment on whether states relying on state programs should be authorized to include a different form of standard in their plans so long as they demonstrate the equivalency of such standards to the level of stringency required under the final EG, and how such equivalency demonstrations can be made in a rigorous and consistent way.

The EPA also proposed to require that, in situations where a state wishes to rely on state programs (statutes and/or regulations) that pre-date finalization of the EG proposed in this document to satisfy the requirements of CAA section 111(d), the state plan should identify which aspects of the state programs are being submitted for approval as federally enforceable requirements under the plan, and include a detailed explanation and analysis of how the relied upon state programs are at least as stringent as the requirements of the final EG. The EPA noted that the completeness criteria in 40 CFR 60.27a(g) requires a copy of the actual state law/regulation or document submitted for approval and incorporation into the state plan. Put another way, where a state is relying on a state program for its plan, a copy of the pre-existing state statute or regulation underpinning the program would be required by this criterion and would be a critical component of the EPA's evaluation of the approvability of the plan. The EPA solicited comment on various ways in which state programs can be adopted into state plans particularly in situations where state programs that regulate both designated

facilities and sources not considered as designated facilities under this EG could be tailored for a state plan to meet the requirements of CAA section 111(d).

The EPA believes that for states to successfully leverage their state programs to satisfy their CAA section 111(d) state plan obligations, specific criteria need to be identified for states and the EPA to follow in determining that a state plan meets the level of stringency required under the final EG, and how such equivalency demonstrations can be made in a rigorous and consistent way. The EPA is proposing such criteria for a source-by-source equivalency determination in this supplemental proposal.

Some commenters requested that the EPA make an equivalency determination on a programmatic, rather than source-specific basis. Some of these commenters suggested that the EPA approve plans that are as stringent as EG even if they do not include identical standards or sources.²⁵⁰ Commenters also suggested that the EPA allow states to include a different form of numerical standard as long as it is determined to be equivalent.²⁵¹ In addition to the suggestion provided, some commenters argued that the EPA is not authorized to approve state limitations that were not derived using CAA section 111(d) standard setting methods.

The following sections discuss EPA's proposal for how states with programs that regulate GHGs in the form of methane from oil and natural gas sources may establish source-by-source equivalency with the EPA's designated facility presumptive standards under EG OOOOc. Consistent with that discussion, the EPA is also proposing to interpret CAA section 111 to authorize states to establish standards of performance for their sources that, in

the aggregate, would be equivalent to the presumptive standards. The 2019 Affordable Clean Energy (ACE) Rule interpreted CAA section 111 to require that each state establish for each source a standard of performance that reduces that source's emissions, and to preclude the type of compliance flexibility that the EPA is now proposing. 84 FR 32556–57 (July 8, 2019). In 2021, the D.C. Circuit vacated the ACE Rule, holding, among other things, that CAA section 111(d) does not preclude states from allowing certain compliance flexibilities, including trading or averaging of emission limits. *American Lung Ass'n v. EPA*, 985 F.3d 914, 957–58 (D.C. Cir. 2021). In 2022, the U.S. Supreme Court reversed the D.C. Circuit's judgment regarding the ACE Rule's embedded repeal of the Clean Power Plan on other grounds. *West Virginia v. EPA*, 142 S. Ct. 2587 (2022). The Supreme Court made clear that CAA section 111 authorizes the EPA to determine the BSER and the amount of emission limitation that state plans must achieve, *id.* at 2601–02, but the Supreme Court did not address the D.C. Circuit's interpretation of CAA section 111 as to the state's compliance flexibilities. *Id.* at 2615–16.

The EPA has reconsidered the ACE Rule's interpretation of CAA section 111, and now disagrees with it. Section 111(d) does not, by its terms, preclude states from having flexibility in determining which measures will best achieve compliance with the EPA's emission guidelines. Such flexibility is consistent with the framework of cooperative federalism that CAA section 111(d) establishes, which vests states with substantial discretion. CAA section 111(d) thus permits each state, when appropriate, to adopt measures that allow its sources to meet their emission limits in the aggregate. In addition, the EPA agrees with the separate set of reasons that the D.C. Circuit gave in holding that CAA section 111(d) does not preclude a state from allowing its sources compliance flexibilities. *American Lung Ass'n v. EPA*, 985 F.3d 914, 957–58. Thus, it is the EPA's

²⁵⁰ See Docket ID Nos. EPA–HQ–OAR–2021–0317–0581, EPA–HQ–OAR–2021–0317–0775, EPA–HQ–OAR–2021–0317–0926, and EPA–HQ–OAR–2021–0317–1267.

²⁵¹ See Docket ID Nos. EPA–HQ–OAR–2021–0317–0558, EPA–HQ–OAR–2021–0317–0761, EPA–HQ–OAR–2021–0317–0769, and EPA–HQ–OAR–2021–0317–1267.

position that CAA section 111(d) authorizes the EPA to allow states, in particular rules, to achieve the requisite emission limitation through the aggregate reductions from their sources, and the EPA is accordingly proposing to authorize states to leverage their state programs to satisfy their CAA section 111(d) state plan obligations pursuant to EG OOOOc, subject to requirements discussed in the following sections.

The EPA intends shortly to propose revisions to the implementing regulations for CAA section 111(d) at 40 CFR part 60, subpart Ba. The EPA intends, in that rulemaking, to further clarify that CAA section 111(d) and the implementing regulations authorize the EPA to, in particular rules, allow states flexibility and discretion in establishing standards of performance that meet the emission guidelines, including standards that permit their sources to comply via methods such as trading or averaging. The EPA encourages interested persons to submit comments on this issue in that rulemaking for the implementing regulations, and the EPA intends to finalize that rulemaking before finalizing this oil and gas rulemaking.

b. Types of Equivalency Evaluations

For purposes of this supplemental proposal, the EPA contemplated two types of equivalency evaluations that could be considered when comparing state programs against the stringency of EG OOOOc. These include: (1) Total program evaluation, and (2) source-by-source evaluation.

i. Total Program Evaluation

The first type of equivalency evaluation the EPA assessed is a total program evaluation, meaning assessing reductions and controls across all or different designated facilities. A total program evaluation could entail that some sources would get more reductions than the presumptive standards in the EG and others less reductions, but overall reductions are equal or greater than what would be achieved in the aggregate across all designated facilities by implementing the presumptive standards. A total program evaluation may look different for states that have designated facilities in the production, processing, and transmission and storage segments compared to states that only have designated facilities in the transmission and storage segment. The EPA recognizes that potentially allowing for total program equivalency could, in theory, reduce burden on states by allowing states with programs to rely more on those programs for their state

plan submittal without needing to revise standards for specific designated facilities in order to match the presumptive standards. Furthermore, the EPA recognizes that burden may be reduced for owners and operators of designated facilities because they would not have to comply with two different sets of regulations. However, the EPA has identified the following challenges and complexities that are unique to the Crude Oil and Natural Gas source category and is therefore proposing to disallow state plans from using total program equivalence to meet the requirements of a final OOOOc EG.

One such consideration is that state programs may include sources that are not designated facilities. For example, New Mexico, Pennsylvania, and Ohio have state standards for pigging activities. The EPA is not proposing to determine a BSER or presumptive standards for pigging activities in this supplemental proposal. Because CAA section 111(d)(1) only provides that state plans may include standards of performance and certain other requirements for designated facilities, the EPA interprets the statute as not allowing the EPA to approve, and thereby render federally enforceable, state plan requirements that extend to sources that are not designated facilities. Therefore, it is not appropriate to allow a state to account for non-designated facilities as part of their state plan submission for any purpose, including for demonstrating program equivalency, even if a state regulates such sources as a matter of state law.²⁵²

In addition, the EPA also interprets CAA section 111(d) as not allowing the EPA to approve state plan requirements for different pollutants than those designated pollutants that are regulated in the EG. The EPA is aware that while numerous states have programs in place that regulate emissions from the designated facilities that the EPA is proposing presumptive standards for, many of those programs do not regulate GHGs in the form of limitations on methane.

The EPA also proposed in the November 2021 proposal that states are generally expected to establish the same non-numerical standards and if a state chooses to utilize a different design, equipment, work practice, and/or operational standard then the state must include in its plan a demonstration of equivalency that is consistent with alternative means of emissions

limitations (AMEL) provisions. Some state commenters agreed with the EPA that states are expected to establish the same non-numerical standards.²⁵³ The EPA recognizes if a state sought to utilize a different design, equipment, work practice, and/or operational standard, a demonstration of equivalency that is consistent with AMEL provisions would likely be technically difficult because many of the presumptive standards in the EG OOOOc are work practice standards that do not quantify emissions. This would suggest that the equivalency evaluation would need to be a qualitative analysis rather than a quantitative analysis because not all states have comprehensive source and source-specific emissions inventory data to base a stringency comparison on emissions reductions alone. The EPA believes this qualitative comparison would be extremely complicated on a holistic total program basis given that there are nine types of designated facilities with proposed presumptive standards, of which, five have numerical limits and two are in the format of work practice standards. Without a clear structure for this evaluation to address the complexities of the Crude Oil and Natural Gas source category, the EPA is concerned that emission reductions and controls consistent with the EG, and consistency of implementation across state plans, would be compromised. Similarly, the EPA proposed that for designated facilities with numerical presumptive standards, states are expected to establish the same form of numerical standards, but the EPA also took comment on whether to allow states to include a different form of numerical standards for these facilities so long as states demonstrate equivalency. Some state commenters suggested that the ability to include a different form of numerical standard in state plans is consistent with the cooperative federalism structure of CAA section 111(d).²⁵⁴ While states asked for this flexibility, state commenters did not clearly provide specific examples of where a state already has a different form of a numerical standard that would necessitate this flexibility. The EPA is also concerned that there may be insufficient state comprehensive source and source-specific emissions inventory data to make the requisite technical evaluation.

²⁵² The EPA acknowledges that states may choose to regulate non-designated facilities under state law for other purposes than to satisfy their CAA section 111(d) state plan submission.

²⁵³ See Docket ID No. EPA-HQ-OAR-2021-0317-1267.

²⁵⁴ See Docket ID No. EPA-HQ-OAR-2021-0317-1267.

Another complicating scenario informing the EPA's proposal to disallow total program equivalence is that there are instances where a state covers part or subset of the EG designated facility's applicability definitions. For example, Colorado requires the use of non-emitting²⁵⁵ pneumatic controllers with specific exceptions. One exception is that operators do not have to retrofit their controllers to become non-emitting if on a company-wide basis, the average production from producing wells in 2019 is less than 15 barrel of oil equivalent/day/well. However, the EPA's supplemental proposal for pneumatic controllers, as discussed in section VII.D of this preamble, proposes a methane emission rate of zero with no applicability site wide production or other threshold thus covering a broader group of pneumatic controllers. If the EPA were to permit total program equivalence where state programs do not align with the EG, then there could be situations where a state would be allowed to forgo regulating some designated facilities that the EPA has determined are reasonable to control.

For these reasons and the critical need to provide clear regulatory certainty to the hundreds of thousands of designated facilities in this uniquely large source category, the EPA does not think a total program evaluation would guarantee that the same emissions reductions as required by the EG would be achieved. The EPA solicits comments on how a total program evaluation could be established in a way that would address the complexities of the Crude Oil and Natural Gas source category and concerns the EPA has identified.

²⁵⁵ The terms "zero emissions" and "non-emitting" are used to describe pneumatic controllers. In Colorado, 5 CCR Regulation 7, Part D, Section III, defines a "non-emitting" controller as "a device that monitors a process parameter such as liquid level, pressure or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to: no-bleed pneumatic controllers, electric controllers, mechanical controllers and routed pneumatic controllers." A routed pneumatic controller is defined as "a pneumatic controller that releases natural gas to a process, sales line or to a combustion device instead of directly to the atmosphere." The EPA is proposing that pneumatic controllers must be "zero emission" controllers. The difference in non-emitting, as defined by Colorado and zero emissions, as proposed in this action, is that pneumatic controllers for which emissions are captured and routed to a combustion device are not considered to be "zero emission" controllers. Therefore, routing to a combustion device is not an option for compliance with the proposed EG OOOOc.

ii. Source-by-Source Evaluation

The second type of equivalency considered is a source-by-source evaluation for a specific designated facility, such as between all storage vessels located in a state or between a subset of centrifugal compressors. A source-by-source evaluation could entail a state conducting equivalency evaluation for one or more designated facilities and their respective presumptive standards. In theory, if a state were to do a source-by-source evaluation for each individual designated facility in its state, this could be considered a form of total program evaluation that is distinct from the type of total program evaluation described above that the EPA is proposing to disallow, where equivalence can be evaluated across different designated facilities rather than designated facilities of the same type. A source-by-source evaluation assumes that all sources in a state that meet the applicability definition for a specific designated facility (e.g., pneumatic controllers, pneumatic pumps, and reciprocating compressors), would in the aggregate have to achieve the same or better reductions of the same designated pollutant as if the state instead imposed the presumptive standards required under the EG. A source-by-source evaluation, in theory, may push states to make changes to their state rules, which may increase burden on states, but is likely a more reliable way to determine that the state is achieving all emission reductions equivalent to implementing the presumptive standards. Given that state programs do vary considerably, a source-by-source evaluation would allow states to pick and choose which state standards they want to leverage for purpose of their state plan development. It is theoretically less technically difficult to evaluate equivalency on a source-by-source basis for the Crude Oil and Natural Gas source category compared to total program equivalence. The EPA is proposing five basic criteria for when states may use a source-by-source evaluation as part of their state plans (discussed in section V.B.2.b.iii of this preamble).

An example of a source-by-source stringency comparison is the comparison the EPA prepared when assessing the stringency of state fugitive emissions monitoring programs compared to what was required under NSPS OOOOa.²⁵⁶ Similar to that

²⁵⁶ Memorandum: Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR part 60,

example, the EPA proposes that any stringency comparison conducted to determine equivalence with the proposed presumptive standards that are work practices will need to be designated facility specific and the qualitative assessment will need to be tailored to ensure that the correct technical metrics are being compared.

iii. Source-by-Source Evaluation Criteria and Methodology

In order to implement a source-by-source evaluation, the EPA is proposing five basic criteria to determine whether a source-by-source evaluation can be considered for equivalency. The criteria are: (1) Designated facility, (2) designated pollutant, (3) standard type/format of standard (e.g., numeric, work practice), (4) emission reductions (with consideration of applicability thresholds and exemptions), and (5) compliance assurance requirements (e.g., monitoring, recordkeeping, and reporting).

In the following paragraphs, the EPA proposes a source-by-source equivalency step-by-step approach followed by an example for hypothetical state rules illustrating how states could implement the proposed approach when conducting a state rule equivalency determination with the proposed presumptive standards.

Step One. Is state rule designated facility definition, pollutant, and format the same? The first questions that a state needs to answer is whether their program defines their regulated emissions source similar to how the EPA defines a designated facility. Do their program requirements for the designated facility regulate the same pollutant, and is the format of the standard the same (e.g., work practice or performance based numerical standard)? If the answer is no to any of these questions (e.g., state program regulates VOC and not methane), then the state plan cannot include an equivalency determination with the EPA's proposed presumptive standards for the designated facility. If the answer is yes to all of these questions, a state would proceed to Step Two.

Step Two. Emissions Reductions. A state plan needs to include a demonstration that the state requirements for designated facilities achieve the same or greater emissions reduction as the designated facility presumptive standards. A state would have several options to make this demonstration.

subpart OOOOa. See Document ID No. EPA-HQ-OAR-2017-0483-2277.

The first option would be to make a demonstration that the designated facility state standard achieves the same emission reduction as the designated facility BSER analysis using the EPA model plant/representative facility. The second option would be to make a demonstration that the designated facility state standard achieves the same or greater emissions reduction “in real life” as the designated facility model plant/representative facility emission reduction in the BSER analysis. The third option would be that a state could apply the designated facility presumptive standard to “real life” (e.g., using activity (number of sources) and actual emissions data) and calculate the state-wide emission reduction that would be achieved, and then demonstrate that the state program requirements for a designated facility would achieve the same or greater emissions reduction. If emissions reductions from the implementation of the state rule are less than would be achieved from the implementation of the presumptive standards, the state

cannot make an equivalency determination with the EPA’s proposed presumptive standards. If emissions reductions from the implementation of the state rule are the same or greater than would be achieved from the implementation of the presumptive standards, a state would proceed to Step Three.

Step Three. Make demonstration that compliance measures included for a designated facility under a state program are at least as effective as those in the presumptive standard. Once a state has determined that the emission reductions from the implementation of the state requirements for a designated facility are the same or greater than would be achieved by the implementation of the presumptive standards for a designated facility under Step Two, a state plan would need to include a demonstration that compliance measures (e.g., monitoring, recordkeeping and reporting requirements) are sufficient to ensure continued compliance with the standards and projected emission reductions.

Centrifugal Compressor Examples—Comparison of Primary Presumptive Standards With 4 Hypothetical Examples.

Table 37 provides examples of the application of the steps outlined above for five hypothetical state rules for reciprocating compressors at gathering and boosting stations in the production segment. The parameters for the presumptive standard for reciprocating compressors are as follows.

(1) The designated facility is a single reciprocating compressor.

(2) The designated pollutant is methane, using volumetric flow rate as a surrogate for methane).

(3) The standard type/format of standard is a numerical standard (2 scfm volumetric flow rate).

(4) The estimated methane emission reductions for the model compressor in the BSER analysis for the presumptive standard was 92 percent reduction.

(5) The compliance assurance requirements include the requirement to measure the flow rate once every 8,760 operating hours and maintain records.

TABLE 37—RECIPROCATING COMPRESSOR DESIGNATED FACILITY PRESUMPTIVE STANDARDS EQUIVALENCY EVALUATION EXAMPLES

Designated facility requirements	Equivalency determination steps		
	Step one—applicability and format of standard	Step two—emission reduction	Step three—compliance assurance measures
Example A: <i>Designated Facility:</i> Single Reciprocating Compressor at Gathering and Boosting. <i>Designated Pollutant:</i> Methane. <i>Format of Standard:</i> Work Practice (Change out rod packing every 3 years). <i>Estimated Emission Reduction (Basis):</i> 56% (model compressor basis). <i>Compliance Assurance Requirements:</i> Records of changeout.	FAIL—format of standard not equivalent.		
Example B: <i>Designated Facility:</i> Single Reciprocating Compressor at Gathering and Boosting. <i>Designated Pollutant:</i> Total hydrocarbon as Surrogate for Methane. <i>Format of Standard:</i> Numerical (Collect and route to control to achieve 95% reduction). <i>Estimated Emission Reduction (Basis):</i> 95% (model compressor basis). <i>Compliance Assurance Requirements:</i> Performance test of control device, continuous parameter monitoring, recordkeeping and reporting.	PASS	PASS	PASS.
Example C: <i>Designated Facility:</i> Single Reciprocating Compressor at Gathering and Boosting. <i>Designated Pollutant:</i> Total Gas Flow rate as surrogate for methane. <i>Format of Standard:</i> Directed Inspection and Maintenance (Measure flow rate annually and replace or repair if volumetric flow is greater than 3 scfm). <i>Estimated Emission Reduction (Basis):</i> 92% (model compressor basis).	FAIL—format of standard not equivalent.		

TABLE 37—RECIPROCATING COMPRESSOR DESIGNATED FACILITY PRESUMPTIVE STANDARDS EQUIVALENCY EVALUATION
EXAMPLES—Continued

Designated facility requirements	Equivalency determination steps		
	Step one—applicability and format of standard	Step two—emission reduction	Step three—compliance assurance measures
<p><i>Compliance Assurance Requirements:</i> Records of measurements, records of corrective actions if greater than 3 scfm, records of new measurement to demonstrate less than 3 scfm after corrective action.</p> <p>Example D:</p> <p><i>Designated Facility:</i> Single Reciprocating Compressor at Gathering and Boosting.</p> <p><i>Designated Pollutant:</i> Total gas flow rate as surrogate for methane.</p> <p><i>Format of Standard:</i> Numerical: 5 scfm.</p> <p><i>Estimated Emission Reduction (Basis):</i> using analysis of state-wide emissions from actual reciprocating compressors, estimated that presumptive standard would achieve 85% reduction over the state, state rule would achieve 87% reduction..</p> <p><i>Compliance Assurance Requirements:</i> Measure volumetric flow rate once every six months, record results..</p>	PASS	PASS Demonstrated that the “real life” state-wide emission reduction for state rule was greater than the “real-life” reduction for the presumptive standard..	PASS.
<p>Example E:</p> <p><i>Designated Facility:</i> Single Reciprocating Compressor at Gathering and Boosting.</p> <p><i>Designated Pollutant:</i> Total gas flow rate as surrogate for methane.</p> <p><i>Format of Standard:</i> Numerical: 4 scfm.</p> <p><i>Estimated Emission Reduction (Basis):</i> 88% (analysis of state-wide emissions from actual reciprocating compressors).</p> <p><i>Compliance Assurance Requirements:</i> Measure volumetric flow rate once every six months, record results.</p>	PASS	FAIL—did not demonstrate that the BSER presumptive standard model facility reduction was met.	

The EPA solicits comment on the EPA’s proposed state program equivalency demonstration methodology and evaluating criteria for when state plans may include standards of performance based on an equivalency demonstration. Specifically, the EPA solicits comments on other criteria than what the EPA is proposing should be considered; and whether there are other additional qualitative factors/criteria need to be included to make an effective stringency evaluation for different types of different design, equipment, work practice, and/or operational standards.

c. General Permitting Programs

The EPA also recognizes that some states may regulate the designated facilities proposed to be regulated under the EGs through a general permit program. For example, general permits often include standardized terms and conditions related to emissions control, compliance certification, notification, recordkeeping, reporting, and source testing requirements. The EPA is not proposing a regulatory amendment on this point but confirms that the

implementing regulations under subpart Ba allows for standards of performance and other state plan requirements to be established as part of state permits and administrative orders, which are then incorporated into the state plan. See 40 CFR 60.27a(g)(2)(ii).

However, the EPA notes that the permit or administrative order alone may not be sufficient to meet the requirements of an EG or the implementing regulations, including the completeness criteria under 40 CFR 60.27a(g). For instance, a plan submission must include supporting material demonstrating the state’s legal authority to implement and enforce each component of its plan, including the standards of performance. *Id.* at 40 CFR 60.27a(g)(2)(iii). In addition, EG OOOOc may also require demonstrations that may not be satisfied by terms of a permit or administrative order. To the extent that these and other requirements are not met by the terms of the incorporated permits and administrative orders, states will need to include materials in a state plan

submission demonstrating how the plan meets those requirements.

3. Remaining Useful Life and Other Factors (RULOF)

Under CAA section 111(d), the EPA is required to promulgate regulations under which states submit plans establishing standards of performance for designated facilities. While states establish the standards of performance, there is a fundamental obligation under CAA section 111(d) that such standards reflect the degree of emission limitation achievable through the application of the BSER, as determined by the EPA. As previously described, this obligation derives from the definition of “standard of performance” under CAA section 111(a)(1). The EPA identifies the degree of emission limitation achievable through application of the BSER as part of its EG. 40 CFR 60.22a(b)(5).

While standards of performance must generally reflect the degree of emission limitation achievable through application of the BSER, CAA section 111(d)(1) also requires that the EPA regulations permit the states, in

applying a standard of performance to a particular designated facility, to take into account the designated facility's RULOF. The EPA's implementing regulations under 40 CFR 60.24a(e) allows a state to consider a designated facility's RULOF in applying a standard of performance less stringent than the presumptive level of stringency given in an EG to a particular source, provided that the state makes the required demonstration under this provision. However, as described further below, this provision does not provide clear parameters for states on how and when to apply a standard less stringent than the presumptive level of stringency given in an EG to a particular source. The EPA intends to propose clarifying revisions to this provision under the implementing regulations in an upcoming rulemaking that would apply generally to new EG promulgated under CAA section 111(d). While inviting comments on the application of these proposed revisions in the context of the oil and gas sector in this rulemaking, the EPA also encourages the public to provide comments on these proposed revisions more generally in that upcoming rulemaking process to amend the implementing regulations. The EPA intends to finalize that rulemaking before finalizing this oil and gas rulemaking.

Consistent with its intended revisions to the implementing regulations, the EPA is proposing to supersede the current 40 CFR 60.24a(e) by providing requirements specific to EG OOOOc for the consideration of RULOF in state plans to set a less stringent standard for a particular source. The EPA notes that the EPA considers the application of the proposed RULOF provisions to apply in circumstances distinct from source-by-source evaluation discussed earlier in section V.B.2. In other words, these provisions apply where a state intends to *depart* from the presumptive standards in EG OOOOc and propose a less stringent standard for a designated facility (or class of facilities), and not where a state intends to *comply* by demonstrating that a facility or group of facilities subject to a state program would, in the aggregate, achieve equivalent or better reductions than if the state instead imposed the presumptive standards required under the EG. The EPA's proposed RULOF requirements for the application of a less stringent standard and rationale are as follows.

The RULOF provision currently under 40 CFR 60.24a(e) allows states to consider RULOF to apply a less stringent standard of performance for a designated facility or class of facilities if

they demonstrate one of the three following circumstances: unreasonable cost of control resulting from plant age, location, or basic process design; physical impossibility of installing necessary control equipment; or other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable. The implementing regulations also specify that, absent such a demonstration, the state's standards of performance must be "no less stringent than the corresponding" EG. 40 CFR 60.24a(c). This supplemental proposal largely retains the substance of this threshold provision for purposes of EG OOOOc, including the three circumstances under which a less stringent standard of performance may be applied, and provide further clarification of what a state must demonstrate in order to invoke RULOF when submitting a state plan. Specifically, the EPA proposes to require the state to demonstrate that a particular facility cannot reasonably achieve the degree of emission limitation achievable through application of the BSER, based on one or more of the three circumstances. The EPA is also proposing to clarify the third circumstance by specifying that states may apply a less stringent standard if factors specific to the facility are fundamentally different than those considered by the EPA in determining the BSER. Subsection a. describes the statutory and regulatory background, and subsection b. explains the agency's rationale for its proposal. Subsections c-h describe further proposed additions to the RULOF provision in cases where states seek to apply a standard that is less stringent than the degree of emission limitation achievable through application of the BSER. These proposed additions include requirements for the calculation of a less stringent standard, contingency requirements in cases where an operating condition is the basis for RULOF, and the consideration of disproportionately impacted communities. Finally, subsection i. describes the proposal to address cases where states seek to apply a more stringent standard.

a. Statutory and Regulatory Background

The 1970 version of CAA section 111(d) made no reference to the consideration of RULOF in the context of standards for existing sources. In the 1975 regulations promulgating subpart B, however, the EPA included a so-called variance provision. For health-based pollutants, states could apply a standard of performance less stringent

than the EPA's EGs based on cost, physical impossibility, and other factors specific to a designated facility that make the application of a less stringent standard significantly more reasonable. 40 CFR 60.24(f). For welfare-based pollutants, states could apply a less stringent standard by balancing the requirements of an EG "against other factors of public concern." 40 CFR 60.24(d). As part of the 1977 CAA amendments, Congress amended CAA section 111(d)(1) to require that the EPA's regulations under this section "shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." At the time, the EPA considered the variance provision under subpart B to meet this requirement and did not revise the provision subsequent to the 1977 CAA amendments until promulgating new implementing regulations in 2019 under subpart Ba. As part of the 2019 revisions, the EPA removed the health and welfare-based pollutants distinction and collapsed the associated requirements of the previous variance provision into a single, new RULOF provision under 40 CFR 60.24a(e). 84 FR 32520, 32570. The D.C. Circuit vacated several timing-related provisions under 40 CFR part 60, subpart Ba; however, Petitioners did not challenge, and the court did not vacate, the new RULOF provision under 40 CFR 60.24a(e). *Am. Lung Assoc. v. EPA*, 985 F.3d at 991 (D.C. Cir. 2021) (*ALA*).²⁵⁷

b. Rationale for the Proposed Revisions

As previously described, the statute expressly requires the EPA to permit states to consider RULOF for a particular designated facility when applying a standard of performance to that facility. The consideration of remaining useful life in particular can be an important consideration, as the cost of control for a specific designated facility that is not expected to operate in the long term, relative to other designated facilities in the source category, could significantly vary from the average cost calculations done as part of the BSER determination for the source category as a whole. In such an instance, and in others as described throughout this section, a less stringent standard may be more reasonable to

²⁵⁷ The Supreme Court subsequently reversed and remanded the D.C. Circuit's opinion. *West Virginia v. EPA*, 142 S.Ct. 2587 (June 30, 2022). However, no Petitioner sought certiorari on, and the *West Virginia* decision did not implicate, the D.C. Circuit's vacatur of portions of subpart Ba.

apply than a standard of performance that reflects the presumptive level of stringency.

In order to understand how states may have dealt with this issue in their programs, the EPA examined several existing state oil and natural gas regulations and programs. Based on our examination, we did not identify any provision in any of the state oil and natural gas regulations that included a less stringent standard for equipment or operations with a shortened lifespan. The EPA is interested in obtaining information on whether this situation exists in state oil and natural gas rules that we may not have identified in our search. In addition, the EPA is soliciting comment on situations where state rules for industries other than the oil and natural gas industry include less stringent requirements for sources that are soon to retire. If these situations exist, the EPA is not only interested in the less stringent requirements as they compare to the “normal” standards, but also how the state evaluated the suitability of the less stringent requirements.

As currently written, the RULOF provision in subpart Ba does not provide clear parameters for states on how and when to apply a standard less stringent than the presumptive level of stringency given in an EG to a particular source. As written, the references to reasonableness in this provision are potentially subject to widely differing interpretations and inconsistent application among states developing plans, and by the EPA in reviewing them. Without a clear analytical framework for applying RULOF, the current provision may be used by states to set less stringent standards that could effectively undermine the overall presumptive level of stringency envisioned by the EPA’s BSER determination and render it meaningless.²⁵⁸ Such a result is contrary to the overarching purpose of CAA section 111(d), which is generally to

require meaningful emission reductions from designated facilities based on the BSER.

Additionally, while states have discretion to consider RULOF under CAA section 111(d), it is the EPA’s responsibility to determine whether a state plan is “satisfactory,”²⁵⁹ which includes evaluating whether RULOF was appropriately considered. The relevant dictionary meaning of “satisfactory” is “fulfilling all demands or requirements.” The American College Dictionary 1078 (C.L. Barnhart, ed. 1970). Thus, the most reasonable interpretation of a “satisfactory plan” is a CAA section 111(d) plan that meets the applicable conditions or requirements, including those under the implementing regulations that the EPA is directed to promulgate pursuant to CAA section 111(d), including the provisions governing the application of RULOF.²⁶⁰

The EPA’s determination of whether each plan is “satisfactory”, including the application of RULOF, must be generally consistent from one plan to another. If the states do not have clear parameters for how to consider RULOF when applying a standard of performance to a designated facility, then they face the risk of submitting plans that the EPA may not be able to consistently approve as satisfactory. For example, under the current broadly structured provision, two states could consider RULOF for two identically situated designated facilities and apply completely different standards of performance on the basis of the same factors. In this example, it may be difficult for the EPA to substantiate finding both plans satisfactory in a consistent manner, and the states and sources risk uncertainty as to whether each of the differing standards of performance would be approvable. Accordingly, providing a clear analytical framework for EG OOOOc for the invocation of RULOF will provide regulatory certainty for states and the

regulated community as they seek to craft satisfactory plans that the EPA can ultimately approve.

For these reasons, the EPA is proposing the RULOF provision under subpart OOOOc, consistent with the statutory construct and goals of CAA section 111(d), in order to provide states and sources with clarity regarding the requirements that apply to the development and approvability of state plans that consider RULOF when applying a standard of performance to a particular designated facility. Below, we describe the guiding principles for the EPA’s proposed revisions.

CAA section 111(a)(1) requires that the EPA determine the BSER is “adequately demonstrated” for the regulated source category. In determining whether a given system of emission reduction qualifies as BSER, CAA section 111(a)(1) requires that the EPA take into account “the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements.” The EPA’s proposed RULOF provision does so by tethering the states’ RULOF demonstration to the statutory factors the EPA considered in the BSER determination. This is appropriate under the statute because the EPA will have demonstrated that the BSER identified in EG OOOOc is “adequately demonstrated” as achievable for sources broadly within the Crude Oil and Natural Gas source category. Therefore, RULOF is appropriately applied to permit states to address instances where the application of the BSER factors to a particular designated facility is fundamentally different than the determinations made to support the BSER and presumptive level of stringency in the EG. For example, the D.C. Circuit has stated that to be “adequately demonstrated,” the system must be “reasonably reliable, reasonably efficient, and . . . reasonably expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.” *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973). The court has further stated that the EPA may not adopt a standard in evaluating cost that would be “exorbitant,”²⁶¹ “greater than the industry could bear and survive,”²⁶² “excessive,”²⁶³ or “unreasonable.”²⁶⁴ These formulations use reasonableness

²⁵⁸ CAA section 111(d) does not require states to consider RULOF, but rather requires that the EPA’s regulations “permit” states to do so. In other words, the EPA must provide states with the ability to account for RULOF, but states may instead choose to establish a standard of performance that is the same as the presumptive level of stringency set forth in the EGs. The optionality, rather than mandate, for states to account for RULOF supports the notion that this provision is not intended to undermine the presumptive level of stringency in an EG for the source category broadly. Additionally, the EPA notes that it is not aware of any CAA section 111(d) EGs under which an EPA-approved state plan has previously considered RULOF to apply a standard of performance that deviates from the presumptive level of stringency. Clarifying parameters may better enable states to effectively use this provision in developing their state plans.

²⁵⁹ CAA section 111(d)(2)(A) authorizes the EPA to promulgate a Federal plan for any state that “fails to submit a satisfactory plan” establishing standards of performance under CAA section 111(d)(1). Accordingly, the EPA interprets “satisfactory” as the standard by which the EPA reviews state plan submissions.

²⁶⁰ Although there is no case law specifically on the standard of review of a CAA section 111(d)(1) state plan or the EPA’s duty to approve satisfactory plans, the EPA’s action on a CAA section 111(d)(1) state plan is structurally identical to the EPA’s action on a state implementation plan (SIP). Under section 110(k)(3), EPA must approve a SIP that meets all requirements of the Act. *See Train v. NRDC*, 421 U.S. 60 (1975) (discussing the 1970 version of the Act); *Virginia v. EPA*, 108 F.3d 1397, 1408–10 (D.C. Cir. 1995) (discussing the 1970, 1977, and 1990 versions).

²⁶¹ *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999).

²⁶² *Portland Cement Ass’n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975).

²⁶³ *Sierra Club v. Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981).

²⁶⁴ *Ibid.*

in light of the statutory factors as the standard in evaluating cost, so that a control technology may be considered the “best system of emission reduction . . . adequately demonstrated” if its costs are reasonable (*i.e.*, not exorbitant, excessive, or greater than the industry can bear), but cannot be considered the BSER if its costs are unreasonable. Similarly, in making the BSER determination, the EPA must evaluate whether a system of emission reduction is “adequately demonstrated” for the source category based on the physical possibility and technical feasibility of control. Under this construct, it naturally follows that most designated facilities within the source category should be able to implement the BSER at a reasonable cost to achieve the presumptive level of stringency, and RULOF will be applicable only for a subset of sources for which implementing the BSER would impose unreasonable costs or not be feasible due to unusual circumstances that are not applicable to the broader source category that the EPA considered when determining the BSER.²⁶⁵

The RULOF provision we are proposing in this rule is consistent with how the EPA has approached RULOF in the implementing regulations previously. Subparts B and Ba both currently contain the same three circumstances for when states may account for RULOF, and reasonableness in light of the statutory criteria is an element of all three circumstances. Under those subparts as currently written, states may consider RULOF if they can demonstrate unreasonable cost of control, physical impossibility of control, or other factors that make application of a less stringent standard “significantly more reasonable.” 40 CFR 60.24(f), 40 CFR 60.24a(e). The EPA’s proposal for EG OOOOc retains the first circumstance in whole and revises the second one to add “technical infeasibility” of installing a control as a situation where application of consideration of RULOF may be appropriate. The proposal for EG OOOOc further clarifies the third catch-all circumstance, which the first two

circumstances also fall under, by specifying that states may consider RULOF to apply a less stringent standard if factors specific to a designated facility are fundamentally different from the factors considered in the determination of the BSER in EG OOOOc. The proposed third criteria provides parameters for states and the EPA in developing and assessing state plans, as this criterion was previously vague in the implementing regulations and potentially open-ended as to the circumstances under which states could consider RULOF.

The “fundamentally different” standard, which undergirds all three circumstances, is also consistent with other variance provisions that courts have upheld for environmental statutes. For example, in *Weyerhaeuser Co. v. Costle*, 590 F.2d 1011 (D.C. Cir. 1978), the D.C. Circuit considered a regulatory provision promulgated under the Clean Water Act (CWA) that permitted owners to seek a variance from the EPA’s national effluent limitation guidelines under CWA sections 301(b)(1)(A) and 304(b)(1). The EPA’s regulation permitted a variance where an individual operator demonstrates a “fundamental difference” between a CWA section 304(b)(1)(B) factor at its facility and the EPA’s regulatory findings about the factor “on a national basis.” *Id.* at 1039. The court upheld this standard as ensuring a meaningful opportunity for an operator to seek dispensation from a limitation that would demand more of the individual facility than of the industry generally, but also noted that such a provision is not a license for avoidance of the Act’s strict pollution control requirements. *Id.* at 1035.

For the reasons described in this section, the EPA is proposing RULOF provisions for purposes of EG OOOOc by: (1) Including the threshold requirements for consideration of RULOF; (2) adding requirements for calculating a less stringent standard accounting for RULOF; (3) adding requirements for consideration of communities most affected by and vulnerable to the health and environmental impacts from the designated facilities being addressed; and (4) adding requirements for the types of information and evidence the states must provide to support the invocation of RULOF in a state plan. The EPA solicits comment on the proposed provisions described in the following subsections, including the use of the BSER as a central tenet governing the invocation of the RULOF provision.

The EPA also solicits comment about whether, instead of establishing firm

requirements for the application of RULOF, the EPA should instead consider establishing a framework, consistent with the proposed requirements in the following discussion, pursuant to which state plans would be considered presumptively approvable. In this scenario, states would have certainty regarding what type of demonstration the EPA would find satisfactory as they develop their plans, but states could also submit an alternative RULOF demonstration for the EPA’s consideration. In the latter case, states would bear the burden of proving to the EPA that they have proposed a satisfactory alternative analysis and standard, considering all factors relevant to addressing emissions from the source or sources at issue. The EPA also solicits comment on what different approaches might be appropriate for a state in applying RULOF to a particular source and that the EPA should consider in determining whether to finalize the provisions discussed below, either as requirements or as presumptions.

c. Threshold Requirements for Considering Remaining Useful Life and Other Factors

Under the existing RULOF provision in subpart Ba, 40 CFR 60.24a(e), a state may only account for RULOF in applying a standard of performance provided that it makes a demonstration based on one of three criteria. These criteria are: (1) Unreasonable cost of control resulting from plant age, location, or basic process design; (2) physical impossibility of installing necessary control equipment; or (3) other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable. But the existing version of this provision in subpart Ba provides no further guidance on what constitutes reasonableness or unreasonableness for these demonstrations. The EPA proposes this provision and clarifies it for purposes of EG OOOOc to require that in order to account for RULOF in applying a less stringent standard of performance to a designated facility, a state must demonstrate that the designated facility cannot reasonably apply the BSER to achieve the degree of emission limitation determined by the EPA because it entails: (1) An unreasonable cost of control resulting from plant age, location, or basic process design; (2) physical impossibility or technical infeasibility of installing necessary control equipment; or (3) other factors specific

²⁶⁵ This construct is also supported by CAA section 111(d) use of the term “establishing” in directing states to create and set standards of performance. As previously described, “standard of performance” is defined under CAA section 111(a)(1) as reflecting the degree of emission limitation achievable through application of the BSER, which sets the initial parameters for development of the standards of performance by states. The statute does not provide that states may account for RULOF in “establishing” standards of performance in the first instance, but permits states to do so in “applying” such standards to a particular source.

to the facility (or class of facilities) that are fundamentally different from the factors considered in the establishment of the emission guidelines.²⁶⁶ The EPA proposes in EG OOOOc that the first criterion remains the same as under the existing RULOF provision in 40 CFR 60.24a(e). For the second criterion, the EPA is proposing in EG OOOOc to add a reference to technical infeasibility, as a similar yet distinct factor from that of physical impossibility of control. Finally, the EPA is proposing in EG OOOOc to revise the third criterion to capture any circumstance at a specific designated facility that is fundamentally different from the factors the EPA considered in determining the BSER.

The EPA proposes in EG OOOOc to require that, in order to demonstrate that a designated facility cannot reasonably meet the presumptive level of stringency based on one of these three criteria, the state must show that implementing the BSER is not reasonable for the designated facility due to fundamental differences between the factors the EPA considered in determining the BSER, such as cost and technical feasibility of control, and circumstances at the designated facility. Per the requirements of CAA section 111(a)(1), the EPA determines the BSER by first identifying control methods that it considers to be adequately demonstrated, and then determining which are the best systems by evaluating (1) the cost of achieving such reduction, (2) any non-air quality health and environmental impacts, (3) energy requirements, (4) the amount of reductions, and (5) advancement of technology. Accordingly, the state plan must show that there are fundamental differences between a designated facility and the EPA's BSER determination based on the EPA's consideration of any of these factors.

For instance, if the state could demonstrate that the cost-per-ton was significantly higher at a specific designated facility than estimated by the EPA in the BSER analysis, and/or that a specific designated facility does not have adequate space to reasonably accommodate the installation, and/or that it is technically infeasible to comply with the presumptive standard based on source-specific technical barriers that are fundamentally different than those considered in the EPA's

BSER determination, that designated facility may be evaluated for a less stringent standard because of the consideration of RULOF.

However, states may not invoke RULOF based on minor, non-fundamental differences. There could be instances where a designated facility may not be able to comply with the level of stringency required by EG OOOOc based on the precise metrics of the BSER determination but is able to do so within a reasonable margin. For example, the costs and cost effectiveness could be slightly higher than estimated by the EPA for the BSER for the presumptive standard, but that would not invoke RULOF. Similarly, there might also be instances where the EPA determines the BSER for a designated facility as a particular technology, but a particular designated facility does not currently have the capability to implement that technology, or it would be cost prohibitive to gain that capability. However, if that designated facility has the ability instead to reasonably install a different, non-BSER technology to achieve the presumptive level of stringency, the designated facility would not be eligible for a less stringent standard that accounts for RULOF.

Following are a few illustrative examples. The EPA is proposing to determine the BSER for wet seal centrifugal compressors designated facility an emission standard of 3 scfm volumetric flow rate. As described in section IV.G of this preamble, the cost effectiveness of complying with the 3 scfm emission standard is estimated to be approximately \$711 per ton of methane reduced for compressors in the transmission and storage segment. Therefore, under the proposed RULOF requirements for this EG, the state could evaluate the cost effectiveness of implementing the BSER for a particular wet seal centrifugal compressor in order to achieve the presumptive standard. As noted above, the first criterion a state may use to justify RULOF in applying a standard of performance is unreasonable cost of control resulting from plant age, location, or basic process design. If a state determined that for a centrifugal compressor affected facility in their state, the cost effectiveness was \$71,000 per ton of methane removed, that would represent a valid demonstration of unreasonable cost of control. However, a slightly higher cost effectiveness (e.g., \$1,000 per ton, which is well within the range the EPA deems to be cost-effective) may be representative of a minor difference that would not represent a valid demonstration for unreasonable cost.

This example is only for illustrative purposes and should not be interpreted to represent the difference that must exist to demonstrate unreasonable cost of control (i.e., the cost effectiveness does not need to be two orders of magnitude higher than the presumptive standard to be considered unreasonable).

By way of further example, for the pneumatic controller designated facility, the EPA determined that use of non-venting controllers is BSER. At sites without electrical power, compliance solutions include solar-powered controllers, a generator which powers electrical controllers or an instrument air system, capturing the emissions and routing them to a process, or installing self-contained controllers. There could be physical constraints that impact the installation of solar panels or a generator, and there may be technical infeasibility issues related to ability to route to a process or to use self-contained controllers. If a state determined that it would be physically impossible and technically infeasible to install non-venting controllers at a designated facility given the size and physical constraints needed to install it, the lack of a process that can accept the gas, or operational conditions that would not support the use of a self-contained controller, this would represent a valid demonstration of physical impossibility or technical infeasibility of installing necessary control equipment.

As a third example of how RULOF may not be used is in the case of the super-emitter response program. Upon notification of an emission event over 100 kg/hr, the program requires an owner/operator to do a root cause analysis to determine the source of the emissions event and either take corrective action or explain why no corrective action was warranted. Because it is not known what the source of the emissions event is prior to the root cause analysis, RULOF cannot be applied in any state plan to exempt an owner or operator from conducting this analysis. Moreover, the EPA anticipates it would generally be inappropriate for a designated facility with a less stringent standard due to RULOF to be permitted to have unintentional and continuing emissions events as high as 100 kg/hr such that the owner/operator would not need to take corrective action under the super-emitter response program.

The EPA solicits comment on the proposal to require states to demonstrate, as a threshold matter when determining whether a state may account for RULOF in order to set a less

²⁶⁶ States may also account for RULOF when applying standards of performance to a class of designated facilities. For purposes of administrative efficiency, a state may be able to calculate a uniform standard of performance that accounts for RULOF using a single set of demonstrations to meet the proposed requirements described in this section if the group of sources has similar characteristics.

stringent standard, that the designated facility cannot reasonably apply the BSER to achieve the presumptive level of stringency determined by the EPA. The EPA further solicits comment on whether other considerations should inform the circumstances under which the EPA should permit RULOF to be used to set a less stringent standard for a particular designated facility. The EPA also discusses and solicits comments later in section V.B.3.g. on the types of information used to support a RULOF demonstration.

d. Calculation of a Standard Which Accounts for Remaining Useful Life and Other Factors

If a state has made the proposed demonstration that accounting for RULOF is appropriate for a particular designated facility, the state may then apply a less stringent standard. The current RULOF provision in subpart Ba is silent as to how a less stringent standard should be calculated, raising the potential for inconsistent application of this provision across states and the potential for the imposition of a standard less stringent than what would be reasonably achievable by a designated facility. In order to fill this gap and ensure the integrity of EG OOOOc, the EPA is proposing several requirements that would apply for the calculation of a standard of performance that accounts for RULOF. The proposed requirements described in this section would provide a framework for the state's analysis in evaluating and identifying a less stringent standard, and in doing so would prevent the application of a standard that is less stringent than what is otherwise reasonably achievable by a particular designated facility.

The EPA is first proposing in EG OOOOc to require that the state determine and include, as part of the plan submission, a source-specific BSER for the designated facility. As described previously, the statute requires the EPA to determine the BSER by considering control methods that it considers to be adequately demonstrated, and then determining which are the best systems by evaluating: (1) The cost of achieving such reduction, (2) any non-air quality health and environmental impacts, (3) energy requirements, (4) the amount of reductions, and (5) advancement of technology. To be consistent with this statutory construct, the EPA proposes that in determining a less stringent BSER for a designated facility, a state must also consider all these factors in applying RULOF for that source. Specifically, the plan submission must identify all control technologies

available for the source and evaluate the BSER factors for each technology, using the same metrics and evaluating them in the same manner as the EPA did in developing the EG using the five criteria noted above.²⁶⁷

We are further proposing that the standard must be in the same form (e.g., numerical rate-based emission standard) as required by the EG OOOOc presumptive standard. The EPA notes there may be cases where a state determines that a designated facility cannot reasonably implement the BSER but can instead reasonably implement another control measure to achieve the same level of stringency required by an EG. In such cases, the standard of performance that reflects the designated facility-specific BSER would be the same level of stringency as the degree of emission limitation achievable through application of the EPA's BSER.

The EPA solicits comment on these proposed requirements for the calculation and form of the less stringent standard that accounts for remaining useful life and other factors. The EPA believes that the five identified BSER factors generally address all relevant information that states would reasonably consider in evaluating the emission reductions reasonably achievable for a designated facility. Moreover, the EPA considers that that these factors provide states with the discretion to weigh these factors in determining the BSER and establishing a reasonable standard of performance for the source. However, the EPA solicits comments on whether there are additional factors, not already accounted for in the BSER analysis, that the EPA should permit states to consider in determining the less stringent standard for an individual source. The EPA also solicits comments on whether we should consider these factors to be part of a presumptively approvable framework for applying a less stringent standard of performance, rather than requirements, and, if so, what different approaches states might use to evaluate and identify less stringent standards that the EPA should consider to be satisfactory in evaluating state plans that apply RULOF.

The EPA also notes that CAA section 111(d) requires that state plans include measures that provide for the implementation and enforcement of a standard of performance. This requirement therefore applies to any

standard of performance established by a state that accounts for RULOF. Such measures include monitoring, reporting, and recordkeeping requirements, as required by 40 CFR 60.25a, as well as any additional measures specified under EG OOOOc. In particular, any standard of performance that accounts for RULOF is also subject to the requirement under subpart Ba that the state plan submission include a demonstration that each standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable. 40 CFR 60.27a(g)(3)(vi).

e. Contingency Requirements

The EPA recognizes that a source's operations may change over time in ways that cannot always be anticipated or foreseen by the EPA, state, or designated facility. This is particularly true where a state seeks to rely on a designated facility's operational conditions, such as the source's remaining useful life or restricted capacity, as a basis for setting a less stringent standard. If the designated facility subsequently changes its operating conditions after the state applies a less stringent standard of performance, there is potential for the standard to not match what is reasonably achievable by a designated facility, resulting in forgone emission reductions and undermining the level of stringency set by EG OOOOc. For example, a state may seek to invoke RULOF for a designated facility located at a well site (e.g., storage vessel) during a time when oil prices are low. The market demand may prompt the owner or operator to shut the well site which may not have been anticipated by the BSER. The well site may be shut in for the duration of the compliance period required by an EG. Under this scenario, the state may be able to demonstrate that it is not reasonably cost effective for the designated facility to implement the BSER in order to achieve the presumptive level of stringency, and the state could set a less stringent standard of performance for this storage vessel designated facility. However, because market conditions are not a physical constraint on the designated facilities operations, it is possible that oil prices can increase in the future therefore causing the production demand to increase without any other legal constraint.

The implementing regulations do not currently address this potential scenario. To address this issue, the EPA is proposing for purposes of EG OOOOc to add a contingency requirement to the RULOF provision that would require a state to include in its state plan a condition making a source's operating

²⁶⁷ To the extent that a state seeks to apply RULOF to a class of facilities that the state can demonstrate are similarly situated in all meaningful ways, the EPA proposes to permit the state to conduct an aggregate analysis of these factors for the entire class.

condition, such as remaining useful life or restricted capacity, enforceable whenever the state seeks to rely on that operating condition as the basis for a less stringent standard. This requirement would not extend to instances where a state applies a less stringent standard on the basis of an unalterable condition that is not within the designated source's control, such as technical infeasibility, space limitations, water access, or subsurface reservoir and geological conditions. Rather, this requirement addresses operating conditions such as operation times, operational frequency, process temperature and/or pressure, flow rate, fuel parameters, and other conditions that are subject to the discretion and control of the designated facility.

As previously discussed, the state plan submission must also include measures for the implementation and enforcement of a standard that accounts for RULOF. For standards that are based on operating conditions that a facility has discretion over and can control, the operating condition and any other measure that provides for the implementation and enforcement of the less stringent standard must be included in the plan submission and as a component of the standard of performance. For example, if a state applies a less stringent standard for a storage vessel designated facility on the basis that the storage vessel has less throughput than maximum capacity of the storage vessel (*e.g.*, due to the current well production, or a state permit limit), the plan submission must include an enforceable requirement for the source to operate at or below that capacity factor, and include monitoring, reporting, and recordkeeping requirements that will allow the state, the EPA, and the public to ensure that the source is in fact operating at that lower capacity.

The EPA notes there may be circumstances under which a designated facility's operating conditions change permanently so that there may be a potential violation of the contingency requirements approved as federally enforceable components of the state plan. For example, a storage vessel designated facility that was previously running at lower throughput now plans to run at a higher throughput full time, which conflicts with the federally enforceable state plan requirement that the facility operate at the lower throughput. To address this concern, a state may submit a plan revision to reflect the change in operating conditions. Such a plan revision must include a new standard of performance that accounts for the change in

operating conditions. The plan revision would need to include a standard of performance that reflects the level of stringency required by EG OOOO and meet all applicable requirements, or if a less stringent standard is still warranted for other reasons, the plan revision would need to meet all of the applicable requirements for considering RULOF.

The EPA requests comment on the proposed contingency requirements to address the concern that a designated facility's operations may change over time in ways that do not match the original rationale for a less stringent standard.

f. Requirements Specific to Remaining Useful Life

Remaining useful life is the one "factor" that CAA section 111(d) explicitly requires that the EPA permit states to consider in applying a standard of performance. The current RULOF provision generally allows for a state to account for remaining useful life to set a less stringent standard. However, the provision does not provide guidance or parameters on when and how a state may do so. Consistent with the principles described previously in this section, the EPA is proposing certain requirements for when a state seeks to apply a less stringent standard on grounds that a designated facility will retire in the near future.

The EPA is proposing to require that in order to account for remaining useful life in setting a less stringent standard for a particular designated facility, the state plan must identify the source's retirement date and substantiate why this retirement date qualifies for the imposition of a less stringent standard. The state plan must include a demonstration of why the source's remaining useful life based on its retirement date reasonably warrants a less stringent standard and does not undermine the control objectives of the EG and CAA section 111(d) itself.

This demonstration may take into account considerations in relation to the remaining useful life such as the time needed to purchase and install equipment required to comply, the time needed to develop a compliance plan and secure the services of specialized contractors to perform services required for compliance, the expected window of time needed to obtain approvals of outside agencies, the time needed to conduct any required community outreach or public hearings, as well as other potential factors.

However, the EPA is proposing that one consideration must be addressed in every case to substantiate that the remaining useful life qualifies the

imposition of a less stringent standard. That is, the state must demonstrate that the cost of control is unreasonable in relation to the retirement date.

When the EPA determines a BSER, it considers cost and, in many instances, the EPA specifically considers annualized costs associated with payment of the total capital investment of the technology associated with the BSER. In the estimation of this annualized cost, the EPA assumes an interest rate and a capital recovery period, sometimes referred to as the payback period. For example, in the estimation of the annual costs for the installation of an instrument air system to power pneumatic controllers with compressed air a medium-sized transmission and storage site, the EPA estimates that the total capital investment (equipment and installation) of the system would be \$76,481. For the BSER analysis, the EPA assumed an interest rate of seven percent and a capital recovery period of 15 years. This means that the annual cost of recovering the initial capital investment including interest, was \$8,397 per year for 15 years. The total annual cost includes this capital recovery cost plus the additional operation and maintenance cost of the equipment (additional beyond what would be required for a natural gas-driven controller system). For this example, the additional operation and maintenance cost was estimated to be \$2,816 per year, resulting in a total annual cost of \$11,213 and a cost effectiveness of \$1,250 per ton of methane removed, which is a value within the range considered reasonable by the EPA.

Therefore, for this example, the cost effectiveness is reasonable considering a capital recovery period, or payback period, of 15 years. If the remaining useful life was less than 15 years, the result could be a cost effectiveness that is outside of the range considered reasonable by the EPA. For example, consider a remaining useful life of six years. The resulting capital recovery cost would be \$26,742 per year and total annual cost would be \$29,196. This would yield a cost effectiveness of \$1,834 per ton of methane removed, which would still be in the range considered reasonable by the EPA. Therefore, the state would not be able to claim that the costs were unreasonable for a remaining useful life of six years. However, if the remaining useful life were only two years, the capital recovery cost would be \$70,502 per year and the total annual cost would be \$72,956. The cost effectiveness of this would be almost \$4,600 per ton of methane removed, which is outside of

the range considered reasonable by the EPA. In this situation, this could potentially be used as part of a demonstration that may qualify the remaining useful life for the imposition of a less stringent standard.

Note that this specific example is only for illustrative purposes. Specifically, for pneumatic controller designated facilities, there are compliance options (e.g., electric controllers) that are considerably less expensive than the installation of an instrument air system. A state would have to demonstrate unreasonable cost of control for each of the identified compliance options, not just one.

The EPA proposes that the only cost factor that should be considered in a remaining useful life determination of cost unreasonableness is whether there is a significant capital investment required to design, purchase, and install equipment. A BSER based on compliance measures that do not require such upfront capital expenditures would have been demonstrated to have reasonable costs in the EPA's analysis for the presumptive standards. This would largely be the case if the affected facility operates for two years or 50 years. Therefore, the EPA does not believe that all types of designated facilities should be eligible for a determination of unreasonable costs associated with remaining useful life. Accordingly, the proposed rule would only allow that cost unreasonableness be considered in a state's demonstration that a source's remaining useful life based on its retirement date reasonably warrants a less stringent standard for the following types of designated facilities: oil wells with associated gas, storage vessels, pneumatic controllers, and pneumatic pumps. A cost unreasonableness determination would not be allowed for any other designated facility types. Note that this would not necessarily prohibit a state from making a demonstration for these other types of designated facilities, as some of the other factors mentioned above (e.g., time needed to develop a compliance plan and secure the services of specialized contractors to perform services required for compliance) could be relevant for such facilities. However, a state could not rely on unreasonable cost in determining that remaining useful life justifies a less stringent standard.

The EPA recognizes that, even with the criteria outlined above, the result could be that different states could make demonstrations that result in different remaining useful life periods for the same types of designated facilities. In order to avoid this potential inequity,

the EPA is requesting comment on whether EG OOOOc should include a single "outermost retirement date" that would define the maximum length of time that would qualify for a designated facility to operate at a less stringent standard based on remaining useful life.

As previously discussed, the EPA is proposing to require that when an operational condition is used as the basis for applying a less stringent standard, the state plan must include that condition as a federally enforceable requirement. Accordingly, if a state applies a less stringent standard by accounting for remaining useful life, the EPA is proposing to require that the state plan must include the retirement date for the designated facility as an enforceable commitment and include measures that provide for the implementation and enforcement of such commitment. For example, the state could adopt a regulation or enter into an agreed order requiring the designated facility to shut down by a certain date, and that regulation or agreed order should then be incorporated into the state plan. The state could also choose to incorporate the shutdown date into a permit, such as a preconstruction permit, and incorporate that permit into the state plan.

The EPA is further proposing to require that the state plan impose a standard that applies to a designated facility until its retirement. This standard must reflect a reasonably achievable source specific BSER and be calculated as described in section IV of this preamble and section XII of the November 2021 proposal and supported by the demonstration described in 2021 TSD²⁶⁸ and the Supplemental TSD²⁶⁹ for this action. The EPA recognizes that, in some instances, a designated facility may intend to retire imminently after the promulgation of an EG, and in such cases it may not be reasonable to require any controls based on the source's exceptionally short remaining useful life. In the case of an imminently retiring source, the EPA is proposing that the state apply a standard no less stringent than one that reflects the designated facility's business as usual. This requirement equitably accommodates practical considerations without impermissibly exacerbating the impacts of the pollutant regulated under CAA section 111(d). The EPA generally expects that an "imminent" retirement

is one that is about to happen in the near term, e.g., within six months.

The EPA solicits comment on the proposed requirements specific to the consideration of remaining useful life as described in this section.

g. The EPA's Standard of Review of State Plans Invoking RULOF

Under CAA section 111(d)(2), the EPA has the obligation to determine whether a state plan submission is "satisfactory." This obligation extends to all aspects of a state plan, including the application of a less stringent standard of performance that accounts for RULOF. The proposed RULOF provision in EG OOOOc are intended to provide parameters not only for the development of CAA section 111(d) state plans, but for the EPA to evaluate the approvability of such plans. The EPA is proposing the following requirements to further bolster the RULOF provision and to facilitate the EPA's review of a state plan to determine whether the plan implementing the RULOF provision is "satisfactory." As an initial matter, the EPA proposes to explicitly require that the state must carry the burden of making the demonstrations required under the RULOF provision. States carry the primary responsibility to develop plans that meet the requirements of CAA section 111(d) and therefore have the obligation to justify any accounting for RULOF that they invoke in support of standards less stringent than those provided by EG OOOOc. While the EPA has discretion to supplement a state's demonstration, the EPA may also find that a state plan's failure to include a sufficient RULOF demonstration is a basis for concluding the plan is not "satisfactory" and therefore disapprove the plan.

The EPA is further proposing that for the required demonstrations, the state must use information that is applicable to and appropriate for the specific designated facility, and the state must show how information is applicable and appropriate. As RULOF is a source-specific determination, it is appropriate to require that the information used to justify a less stringent standard for a particular designated facility be applicable to and appropriate for that source. The EPA anticipates that in most circumstances, site-specific information will be the most applicable and appropriate to use for these demonstrations and proposes to require site-specific information where available. In some instances, site-specific information may not be available, and a state may instead be able to use general information about the Crude Oil and Natural Gas source

²⁶⁸ Document ID No. EPA-HQ-OAR-2021-0317-0166.

²⁶⁹ Located at Docket ID No. EPA-HQ-OAR-2021-0317.

category to evaluate a particular designated facility. In such cases, the state plan submission must provide both the general information and a clear assessment of how the information is applicable to and appropriate for the designated facility. The use of general information must also be consistent with and supportive of the overall assessment and conclusions regarding consideration of RULOF for the specific designated facility.

Finally, the EPA proposes to require that the information used for a state's demonstrations under the new RULOF provisions must come from reliable and adequately documented sources, which presumptively include the following: EPA sources and publications, permits, environmental consultants, control technology vendors, and inspection reports. Requiring the use of such sources will help ensure that an accounting of RULOF is premised on legitimate, verifiable, and transparent information. The EPA solicits comment on the proposed list of information sources and whether other sources should be considered as reliable and adequately documented sources of information for purposes of the RULOF demonstration, including but not limited to reliable and adequately documented sources of cost information.²⁷⁰

These requirements will aid both the EPA in evaluating whether RULOF has been appropriately accounted for, and the public in commenting on the EPA's proposed action on a state plan that includes a less stringent standard on the basis of RULOF. The EPA solicits comment on the proposed requirements described in this section regarding the EPA's standard of review for state plans that invoke consideration of RULOF.

h. Consideration of Impacted Communities

CAA section 111(d) does not specify what are the "other factors" that the EPA's regulations should permit a state to consider in applying a standard of performance. The EPA interprets this as providing discretion for the EPA to identify the appropriate factors and conditions under which the circumstance may be reasonably invoked in establishing a standard less stringent than the EG. Additionally, CAA section 111(d)(2)'s requirement that the EPA determine whether a state

plan is "satisfactory" applies to such plan's consideration of RULOF in applying a standard of performance to a particular facility. Accordingly, the EPA must determine whether a plan's consideration of RULOF is consistent with section 111(d)'s overall health and welfare objectives. While the consideration of RULOF can be warranted to apply a less stringent standard of performance to a particular facility, such standards have the potential to result in disparate health and environmental impacts to communities most affected by and vulnerable to impacts from the designated facilities being addressed by the state plan. Those communities could be put in the position of bearing the brunt of the greater health and environmental impacts resulting from that source implementing less stringent emission controls than would otherwise have been required pursuant to the EG. The EPA finds that a lack of consideration to such potential outcomes would be antithetical to the public health and welfare goals of CAA section 111(d) and the CAA generally.

In order to address the potential exacerbation of health and environmental impacts to vulnerable communities as a result of applying a less stringent standard, the EPA is proposing in EG OOOOc to require states to consider such impacts when applying the RULOF provision to establish those standards. The EPA is proposing to require that, to the extent a designated facility would qualify for a less stringent standard through consideration of RULOF, the state, in calculating such standard, must consider the potential health and environmental impacts on communities most affected by and vulnerable to the impacts from the designated facility considered in a state plan for RULOF provisions. These communities will be identified by the state as pertinent stakeholders under the proposed meaningful engagement requirements described in section V.B.6 of this preamble.²⁷¹

The EPA proposes to require that state plan submissions seeking to invoke RULOF for a source must identify where and how a less stringent standard impacts these communities. In evaluating a RULOF option for a facility, states should describe the health and environmental impacts anticipated from

the application of RULOF for such communities, along with any feedback the state received during meaningful engagement regarding its draft state plan submission, including on any standards of performance that consider RULOF. Additionally, to the extent there is a range of options for reasonably controlling a source based on RULOF, the EPA is proposing that in determining the appropriate standard of performance, states should consider the health and environmental benefits to the communities most affected by and vulnerable to the impacts from the designated facility considered in a state plan for RULOF provisions, and also provide in the state plan submission a summary of the results that depicts the impacts to those communities. This requirement to consider the health and environmental impacts in any standard of performance taking into account RULOF is consistent with the definition of "standard of performance" in CAA section 111(a)(1). This definition requires the EPA to take into account health and environmental impacts in determining the BSER. As described in this section, if a designated facility qualifies for a less stringent standard based on RULOF, the EPA is proposing the state plan must identify a source-specific BSER based on the same factors and metrics the EPA considered in determining the BSER in the EG. Therefore, state plans must consider health and environmental impacts in determining a source-specific BSER informing a RULOF standard, just as the EPA is statutorily required to take into account these factors in making its BSER determination. See section IV.D.1.b.III for an example of the environmental impacts assessed for the EPA's proposed BSER determination for pneumatic controllers.

As an example, the state plan submission could include a comparative analysis assessing potential controls on a designated facility and the corresponding potential benefits to the identified communities in controlling the designated facility. If the comparative analysis shows that a designated facility could be controlled at a certain cost threshold higher than required under the EPA's proposed revisions to the RULOF provision, and such control benefits the communities that would otherwise be adversely impacted by a less stringent standard, the state in accounting for RULOF could choose to use that cost threshold to apply a standard of performance.²⁷²

²⁷⁰ The EPA acknowledges there may be reliable and adequately documented sources of information other than those described in this section. The EPA encourages states to consult with their Regional Offices if there are questions about whether a particular source of information would meet the applicable requirements.

²⁷¹ Pursuant to the proposed meaningful engagement requirements that states must complete prior to the submittal of their state plans, states must identify pertinent stakeholders and meaningfully engage with such pertinent stakeholders, including communities most affected by and vulnerable to the impacts of the plan.

²⁷² As previously described, CAA section 111(d) gives states the discretion to consider RULOF for a particular source and are not required to do so.

Given that states have the discretion rather than mandate to consider RULOF in applying a standard of performance under CAA section 111(d), it is reasonable for states to consider the potential impacts to communities most affected by and vulnerable to the impacts from a particular designated facility in calculating the level of stringency for such standard.

Additionally, under CAA section 111(d)(2)(B), the EPA has the authority to prescribe a Federal plan promulgating a standard of performance for designated facilities located in a state that fails to submit a satisfactory plan. Consistent with the statute's mandate for the EPA's regulations under CAA section 111(d) to permit states to account for RULOF, this provision further directs that the EPA "shall" take into account RULOF in promulgating standards of performance for the source category under the Federal plan. Therefore, because the statute uses the same "other factors" phrasing in both CAA sections 111(d)(1) governing state plans and 111(d)(2) governing Federal plans, the EPA proposes in EG OOOOc to require that impacts to communities most affected by and vulnerable to the impacts from designated facilities be considered in both the state and Federal plan contexts when accounting for RULOF.

The EPA solicits comment on the proposed requirements described in this section for consideration of vulnerable communities in the context of RULOF.

i. Authority To Apply More Stringent Standards as Part of the State Plan

In the November 2021 proposal, the EPA proposed that states are authorized to include in their state plans, and the EPA is authorized to approve, requirements that are more stringent than the EG under the authority of CAA section 116, as interpreted by the Court in *Union Electric v. EPA*, 27 U.S. 246, (1976). 86 FR 63251. The EPA is now proposing that under CAA section 111(d), consistent with the authority conferred by CAA section 116, states may consider RULOF to include more stringent standards of performance in their state plans.

The current RULOF provision in subpart Ba under 40 CFR 60.24a(e) governs instances where states seek to apply a less stringent standard of performance to a particular designated facility. In promulgating this provision,

the EPA received comments contending that if states may consider factors that justify less stringent standards, they must also be permitted to consider factors that would justify greater stringency than required by an EG, such as more expeditious compliance obligations or the retirement of a source. EPA's Responses to Public Comments on the EPA's Proposed Revisions to Emission Guideline Implementing Regulations at 56 (Docket ID No. EPA-HQ-OAR-2017-0355-26740) (July 8, 2019). In response to these comments, the EPA explained that it interpreted the statutory RULOF provision as intended to authorize only standards of performance that are less stringent than the presumptive level of stringency required by a particular EG. *Id.* at 57. The EPA has reevaluated its prior interpretation and is now proposing for purposes of EG OOOOc to interpret that the statute authorizes the EPA to permit states to consider other factors that justify application of a more stringent standard to a particular source than required by an EG. See *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502 (2009). The EPA's rationale for its revised interpretation and proposal is as follows.

As described previously, while standards of performance must generally reflect the presumptive level of stringency identified in the EG, CAA section 111(d) also requires the EPA to permit states to "take into consideration, among other factors, the remaining useful life" in applying a standard of performance to a particular designated facility. Aside from the explicit reference to remaining useful life, the statute is silent as to what the "other factors" are that states may consider in applying a standard of performance. It also silent as to whether the "standard of performance" to be "appl[ie]d" to a "particular source" must be a weaker or stronger standard—the only inference that can be drawn from the statutory language is that RULOF may be used to apply a *different* standard. Therefore, the EPA may reasonably interpret this ambiguity both as to what the "other factors" are that states may use to apply a standard of performance to a particular source, and how such consideration may affect the stringency of such standard. Accordingly, the EPA reasonably interprets this phrase as authorizing states to consider other factors in exercising their discretion to apply a more stringent standard to particular a source. This is a reasonable interpretation of the statute because if Congress intended the RULOF provision

to be used only to allow states to apply less stringent standards, it would have clearly specified that its intent or enumerated "other factors" that are appropriate for relaxing the stringency of a standard. The statute's explicit reference to remaining useful life shows that if there were factors that Congress specifically wanted the EPA to allow or disallow states to consider, it knew how to expressly make its intent clear in the RULOF provision.

In addition to finding that the statute does not preclude the EPA's reasonable interpretation of the statutory RULOF provision as described above, the EPA has reevaluated the bases for its prior interpretation that states may only consider RULOF to apply a less stringent standard and determined those bases were flawed. In making its prior interpretation, the EPA noted that the new regulatory RULOF provision under subpart Ba at 40 CFR 60.24a(e) was substantively similar to the variance provision under subpart B, which authorizes the use of other factors that "make application of a less stringent standard or final compliance time significantly more reasonable." 40 CFR 60.24(f)(3). The EPA reasoned that because the variance provision under subpart B is similar to and predated Congress's addition of the statutory RULOF provision to CAA section 111(d) as part of the 1977 CAA Amendments, "Congress effectively ratified the EPA's implementing regulations' clear construct that remaining useful life and other factors are only relevant in the context of setting less stringent standards." EPA's Responses to Public Comments on the EPA's Proposed Revisions to Emission Guideline Implementing Regulations at 57 (Docket ID# No. EPA-HQ-OAR-2017-0355-26740) (July 8, 2019). The EPA has closely reexamined the variance provision under subpart B and the RULOF provision under CAA section 111(d) and does not find that these provisions support the proposition that Congress clearly ratified the aspect of the variance provision in subpart B allowing states to apply only less stringent standards under certain circumstances. There are notable differences between the subpart B variance provision and the CAA section 111(d) RULOF provision that indicate Congress did not intend to incorporate and ratify all aspects of the EPA's regulatory approach when amending CAA section 111(d) in 1977. Particularly, for pollutants found to cause or contribute to endangerment of public health, subpart B allows states to apply a less stringent standard under

States thus have the authority to choose to impose a more stringent standard, including the presumptive standard, than would be permissible under RULOF for other reasons, e.g. based on consideration of communities other than identified impacted communities.

certain circumstances unless the EPA provides otherwise in a specific EG for a particular designated facility or class of facilities. 40 CFR 60.24(c), (f). Subpart B places no similar exception for states in authorizing them to seek a variance for a standard addressing a pollutant for which the EPA has made a welfare-based, but not public health-based, endangerment finding under 111(b)(1)(A). 40 CFR 60.24(d). By contrast, the statutory RULOF provision does not make a similar distinction between public health and welfare-based pollutants, which the EPA itself acknowledged in promulgating the regulatory RULOF provision in subpart Ba. 84 FR 32570 (July 8, 2019). Therefore, the EPA cannot clearly ascertain whether the statutory RULOF provision ratified the variance provision under subpart B, given that certain key elements of the latter are not present in the former. There is nothing in CAA section 111(d) or the legislative history that suggests Congress enacted the statutory RULOF provision by ratifying certain elements of the regulatory variance provision in subpart B but not others.

Additionally, in taking its prior position that states may only consider RULOF to apply a less stringent standard, the EPA asserted that the legislative history of the 1977 CAA Amendments supported its interpretation. The EPA highlighted the following statement in the House conference report adopting the amendment to add the statutory RULOF provision: “The section also makes clear that standards adopted for existing sources under section 111(d) of the Act are to be based on available means of emission control (not necessarily technological) and must, unless the state decides to be more stringent, take into account the remaining useful life of the existing sources.” H.R. Conf. Rep. No. 94–1742, (Sep. 30, 1976), 1977 CAA Legis. Hist. at 88. Based on this statement, the EPA found that the caveat that states have the choice to not invoke the RULOF provision and instead “be more stringent” suggests that considering RULOF is only intended to allow a state to make a standard less stringent. The EPA now finds that its prior reliance on this legislative history was flawed. The cited statement only speaks to remaining useful life, which is a factor that inherently suggests a less stringent standard, but it is completely silent as to the “other factors” the statute references. Thus, there is no indication that Congress intended to limit the “other factors” that states may apply in developing their plans only to

permit less stringent, and not also more stringent standards. Rather, the cited statement explicitly acknowledges that states may choose to “be more stringent”, which supports the EPA’s interpretation of the statute to permit states to consider other factors to set standards more stringent than the degree of emission limitation achievable through application of the BSER.

Interpreting the statutory RULOF provision as authorizing states to apply a more stringent standard of performance to a particular source is also consistent with the purpose and structure of CAA section 111(d). CAA section 111(d) clearly contemplates cooperative federalism, where states bear the obligation to establish standards of performance. Nothing under CAA section 111(d) suggests that the EPA has the authority to preclude states from determining that it is appropriate to regulate certain sources within their jurisdiction more strictly than otherwise required by federal requirements. To do so would be arbitrary and capricious in light of the overarching purpose of CAA section 111(d), which is to require emission reductions from existing sources for certain pollutants that endanger public health or welfare. It is inconsistent with the purpose of CAA section 111(d) and the role it confers upon states for the EPA to constrain them from further reducing emissions that harm their citizens, and the EPA does not see a reasonable basis for doing so.

Other factors states may wish to account for in applying a more stringent standard than required under an EG include, but are not limited to, early retirements, effects on local communities, and availability of control technologies that allow a source to achieve greater emission reductions. However, the EPA cannot anticipate each and every factor under which a state may seek to apply a more stringent standard. Therefore, the EPA will evaluate on a case-by-case basis the inclusion of a more stringent standard in a state plan addressing EG OOOOc. The EPA is also proposing to require that states seeking to apply a more stringent standard of performance based on other factors must adequately demonstrate that the different standard is in fact more stringent than the presumptive level of stringency. Such standard of performance must meet all applicable statutory and regulatory requirements, including that it is adequately demonstrated,²⁷³ and the

²⁷³ The EPA is not proposing to require the state to conduct a source-specific BSER analysis for purposes of applying a more stringent standard, as

state plan must include measures that provide for the implementation and enforcement of the standard as with any standard of performance under CAA section 111(d).

For the reasons described in this section, the EPA proposes to permit states to consider factors which justify applying a standard of performance that is more stringent than required under an EG OOOOc.

Therefore, for purposes of EG OOOOc, per the authority of CAA sections 111(d) and 116, the EPA proposes to permit states to include more stringent standards of performance in their plans and that the EPA must approve and render such standards as federally enforceable, so long as the minimum requirements of the EG and subpart Ba are met.²⁷⁴ The EPA solicits comment on its proposal as described in this section.

4. Providing Measures That Implement and Enforce Such Standards

As described in the November 2021 proposal, the EPA proposed to require that state plans must also include compliance schedules for the presumptive standards including where states choose to account for RULOF, methods employed to implement and enforce the presumptive standards such that the EPA can review and identify measures that assure transparent and verifiable implementation, and states must include appropriate monitoring, reporting, and recordkeeping requirements to ensure that state plans adequately provide for the implementation and enforcement of the presumptive standards.²⁷⁵ The EPA is proposing to supplement the November 2021 proposal by clarifying that states maintain the same monitoring, reporting, and recordkeeping requirements, or equivalent requirements as described in EG OOOOc for presumptive standards that states adopt in their plans. The EPA further clarifies that where a state plan adopts standards of performance that

the EPA proposes to require for application of a less stringent standard. So long as the standard will achieve equivalent or better emission reductions than required by EG OOOOc, the EPA believes it is appropriate to defer to the state’s discretion to, e.g., choose to impose more costly controls on an individual source.

²⁷⁴ The EPA notes that its authority is constrained to approving measures which comport with applicable statutory requirements. For example, CAA section 111(d) only contemplates that state plans would include requirements for designated facilities regulated by a particular EG; therefore, the EPA concludes that CAA section 116 does not provide it with the authority to approve and render federally enforceable measures on entities other than those on designated facilities.

²⁷⁵ 86 FR 63252 (November 15, 2021).

differ from the presumptive standards, the plan may accordingly include different monitoring, reporting, and recordkeeping requirements than those in the presumptive standards, but such requirements must be appropriate for the implementation and enforcement of the standards and must be determined to be equivalent as described in Section V.B.2. For components of a state plan that differ from any presumptively approvable aspects of the final EG, the EPA will review the approvability of such components through notice and comment rulemaking.

5. Emissions Inventories

In the November 2021 proposal the EPA discussed that the implementing regulations at 40 CFR 60.25a contain generally applicable requirements for emission inventories, source surveillance, and reports. 86 FR 63253 (November 16, 2021). 40 CFR 60.25a(a) requires that state plans shall include an inventory of all designated facilities, including emission data for the designated pollutants. This provision further requires that such data shall be summarized in the plan, and emission rates of designated pollutants from designated facilities shall be correlated with applicable standards of performance. However, due to the very large number of existing oil and natural gas sources,²⁷⁶ and the frequent change of configuration and/or ownership, the EPA recognized that it may not be practical to require states to compile this information in the same way that is typically expected for other industries under other EG. Therefore, the EPA solicited comment on whether to supersede the requirements of 40 CFR 60.25a(a) for purposes of this EG.²⁷⁷

State commenters generally support superseding the implementing regulations and agree that states should be able to document impacted sources differently than other CAA section 111(d) plans.²⁷⁸ While some state commenters have state inventories, others confirmed the EPA's understanding that some states do not have comprehensive tracking systems

for a designated facility inventory and associated emissions.²⁷⁹ Some commenters discussed that the development of such an inventory would be resource intensive with little benefit.²⁸⁰ The State of Colorado referenced their 2020 leak inspection reporting program which suggests there are over 15,000 well production facilities in the state and the State of West Virginia estimates over 54,000 natural gas and over 10,000 crude oil producing wells in the state.²⁸¹ Both states recognize that each well production facility would represent a much greater number of individual designated facilities. The State of West Virginia further described the complexity of inventory development given not only the vast number of sources, but also the frequent change of configurations and ownership within the industry. These points were echoed by the State of Texas which also provided an estimate of the number of production wells in the state, however, they noted that unless a state-wide equipment inventory is conducted the number of designated facilities is unclear.²⁸² Multiple state commenters support the EPA allowing states to leverage existing inventories and emissions data, even if that data might not be fully aligned with the designated facilities in the EG.²⁸³

For purposes of this EG, the EPA does not believe that the inventory and detailed emissions data required under 40 CFR 60.25a(a) is necessary for states to develop standards of performance, and that standards of performance could be developed with a different type of emissions inventory data. For example, the emissions inventory data could be derived from the GHGRP, which collects GHG emissions and activity data annually from applicable facilities conducting petroleum and natural gas systems activities. Facilities use uniform methods prescribed by the EPA to calculate emissions for applicable source types, and the EPA conducts a multi-step verification process to ensure reported data are accurate, complete, and consistent. Reported data are made available to the public through several portals accessible via the EPA's website. The emissions and activity data reported to the GHGRP can be leveraged

to develop standards of performance. While the EPA recognizes that the GHGRP includes a reporting threshold and that GHGRP facility definitions and emission factors might not be fully aligned with the designated facilities in the EG, the GHGRP data represent the same general type of inventory information as the inventory and detailed emissions data required under 40 CFR 60.25a(a). In addition, the EPA does not think it reasonable to burden states to derive information from GHGRP, which the EPA already has, only to resubmit it to the Agency. The EPA notes that emissions inventory data used to develop standards of performance could also be derived from other available existing inventory information available to the state. Therefore, in order to avoid the potential burden that could be imposed by applying 40 CFR 60.25a(a) as written to this EG, and potential burden and duplicative information collection imposed by requiring states to use other inventories such as GHGRP, the EPA proposes to supersede the requirements of 40 CFR 60.25a(a) for purposes of this EG, so that state plans are not required to include an inventory and emissions data as described under this provision.

6. Meaningful Engagement

In the November 2021 proposal, the EPA proposed and solicited comment on requiring states to perform early outreach and meaningful engagement with overburdened and underserved communities during the development process of their state plan pursuant to EG OOOOc.²⁸⁴ The fundamental purpose of CAA section 111 is to reduce emissions from certain stationary sources that cause, or significantly contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare. Therefore, a key consideration in the state's development of a state plan, in any significant plan revision,²⁸⁵ and in the EPA's development of a Federal plan pursuant to an EG promulgated under CAA section 111(d) is the potential impact of the proposed plan requirements on public health and welfare. A robust and meaningful public participation process during plan development is critical to ensuring that the full range of these impacts are understood and considered. The EPA received numerous comments from states supporting the proposed

²⁷⁶ In the U.S. the EPA has identified over 15,000 oil and gas owners and operators, around 1 million producing onshore oil and gas wells, about 5,000 gathering and boosting facilities, over 650 natural gas processing facilities, and about 1,400 transmission compression facilities.

²⁷⁷ The EPA may supersede any requirement in its implementing regulations for CAA section 111(d) if done so explicitly in the EG. See 40 CFR 60.20a(a)(1).

²⁷⁸ The EPA received several comments on this topic. A sampling of these comments is cited in footnotes in this section. See Document ID Nos. EPA-HQ-OAR-2021-0317-0769, EPA-HQ-OAR-2021-0317-0775.

²⁷⁹ See Document ID Nos. EPA-HQ-OAR-2021-0317-0832-A2, EPA-HQ-OAR-2021-0317-0722.

²⁸⁰ See Document ID Nos. EPA-HQ-OAR-2021-0317-0200.

²⁸¹ See Document ID Nos. EPA-HQ-OAR-2021-0317-0775, EPA-HQ-OAR-2021-0317-0424.

²⁸² See Document ID Nos. EPA-HQ-OAR-2021-0317-0419.

²⁸³ See Document ID Nos. EPA-HQ-OAR-2021-0317-1267.

²⁸⁴ See 86 FR 63254 (November 15, 2021).

²⁸⁵ Significant state plan revision includes, but is not limited to, any revision to standards of performance or to measures that provide for the implementation or enforcement of such standards.

requirements for meaningful engagement, providing suggestions based on their own experience and initiatives, while requesting that the EPA provide specificity around meaningful engagement and examples of satisfactory engagement. The EPA also hosted two discussions with representatives of state and local air agencies to hear more about their perspectives on meaningful engagement. The Agency held a similar meeting with communities, tribes, and small businesses to hear their views on meaningful engagement.

Many stakeholders support robust public engagement, especially with communities most affected by and vulnerable to the impacts of the state plan, and some highlight how this type of public engagement aligns with their commitment to EJ.²⁸⁶ State commenters also encouraged the EPA to allow for flexibility to craft plans to the unique economic and demographic features of each state.²⁸⁷ Some states and industry commenters question the EPA's authority to require states to conduct meaningful engagement and seek guidance on alternative procedures for meaningful engagement.²⁸⁸ Other state commenters indicate that states already take EJ initiatives into consideration and some say additional efforts would be redundant and share concern about adequate resources to conduct meaningful engagement.²⁸⁹ State commenters generally advocate for the EPA to provide examples of the types of engagement that will be approvable and seek additional guidance. Industry commenters expressed commitment to support constructive interactions between industry, regulators, and surrounding communities and populations that may be disproportionately impacted.²⁹⁰ Some industry and state commenters express

concern that the meaningful engagement requirement could cause disapproval of a state plan if the EPA fails to provide a definition for meaningful engagement with clear parameters and examples of adequate engagement.²⁹¹

State commenters offer an array of helpful suggestions based on their own experience and initiatives. New Mexico, for example, agreed with the EPA that requiring states to share information and solicit input from stakeholders at critical junctures during plan development will ensure communities have abundant opportunities to participate in the plan development process.²⁹² New Mexico further agreed with the EPA's proposal to give the reasonable notice requirement additional and separate meaning from "public hearing" to ensure the public has reasonable notice of relevant information, as well as the opportunity to participate in the state plan development.

New Mexico discusses that in addition to using traditional communication technologies, even with potential barriers involving accessibility of technologies (e.g., video conferencing, social media, and smart phone applications), these new technologies should also be utilized during the meaningful engagement process and they specifically ask the EPA to permit both new and traditional communication technologies to qualify as a means to conduct meaningful public engagement. New Mexico also suggests that states, local governments, community organizations, and other stakeholders may find it helpful to create organized groups that can help address interstate air quality issues. For example, they participate in the Four Corners Air Quality Group, which could serve as a model for such coordination. New Mexico, along with the Navajo Nation, Colorado, Arizona, and Utah meet regularly to address common air quality issues in the region. The Four Corners Air Quality Group also includes a variety of different stakeholders including community members and organizations and industry leaders. The goals and functions of any cross-border groups can, and should, be crafted to the unique needs of the area(s) in which they serve.

States and Cities provided other examples of strategies for states to consider.²⁹³ They first suggest targeting special notice, by mail, of public

participation opportunities to residents and schools within a certain radius from regulated oil and natural gas facilities. Their second suggestion includes hosting a series of public meetings or workshops to provide background on the purpose of the state plans, the process for developing the plans, and the public comment and hearing process. Third, they suggest assuring that those public meetings, workshops, and hearings are held at times that are convenient for members of the affected community, that translation services are available at such events, and that there are options for participating via phone or videoconference. Fourth, they recommend ensuring that any public meeting, workshop, hearing, or other format for gathering input are safe spaces and that participation does not endanger community members because of immigration or employment status. Fifth, they suggest providing information on a public website and in hardcopy at an accessible location within the community, such as a public library or school. Lastly, they agree that the state plan submission would need to describe and report on the engagement conducted which would be evaluated as part of the state plan completeness determination. Commenters also seek additional guidance on how states could go about making public meetings or workshops safe spaces for undocumented members of overburdened or underserved communities. Similarly, commenters ask if the EPA could specify that information about the rulemaking to be shared at a public meeting or workshop must be translated in communities with linguistic barriers by the EPA's duties under Title VI of the Civil Rights Act.

The EPA previously proposed in EG OOOOc to include certain meaningful engagement in addition to the requirements for notice and public hearing. The notice and public hearing requirements in 40 CFR 60.23a(c)–(f) require the states to conduct one or more public hearings prior to the adoption of any plan. The states are to provide notification to the public by prominent advertisement to the public of the date, time, and place of the public hearing, 30 days prior to the date of such hearing, and the advertisement requirement may be satisfied through the internet. *Id.* at (d).

The EPA recognizes that a fundamental purpose of the Act's notice and public hearing requirements is for all affected members of the public, and not just a particular subset, to participate in pollution control planning processes that impact their health and

²⁸⁶ The EPA received several comments on this topic. A sampling of these comments are cited in footnotes in this section. See Document ID Nos. EPA–HQ–OAR–2021–0317–0581, EPA–HQ–OAR–2021–0317–0808–A1, EPA–HQ–OAR–2021–0317–0921, EPA–HQ–OAR–2021–0317–0938, EPA–HQ–OAR–2021–0317–0814, EPA–HQ–OAR–2021–0317–0832–A2, EPA–HQ–OAR–2021–0317–0727, EPA–HQ–OAR–2021–0317–0775, and EPA–HQ–OAR–2021–0317–1267.

²⁸⁷ See Document ID Nos. EPA–HQ–OAR–2021–0317–0832–A2 and EPA–HQ–OAR–2021–0317–0581.

²⁸⁸ See Document ID Nos. EPA–HQ–OAR–2021–0317–0727, EPA–HQ–OAR–2021–0317–0921, EPA–HQ–OAR–2021–0317–0938, EPA–HQ–OAR–2021–0317–0921, EPA–HQ–OAR–2021–0317–0763, EPA–HQ–OAR–2021–0317–0722.

²⁸⁹ See Document ID Nos. EPA–HQ–OAR–2021–0317–0775 and EPA–HQ–OAR–2021–0317–0727.

²⁹⁰ See Document ID Nos. EPA–HQ–OAR–2021–0317–0808–A1, EPA–HQ–OAR–2021–0317–0445, EPA–HQ–OAR–2021–0317–0819, and EPA–HQ–OAR–2021–0317–0456.

²⁹¹ See Document ID Nos. EPA–HQ–OAR–2021–0317–0921 and EPA–HQ–OAR–2021–0317–0938.

²⁹² See Document ID Nos. EPA–HQ–OAR–2021–0317–0832–A2.

²⁹³ See Document ID Nos. EPA–HQ–OAR–2021–0317–1267.

welfare.²⁹⁴ Accordingly, in order for there to be a meaningful opportunity for the public to participate in hearings on CAA section 111(d) state plans, the notice of such hearings must be reasonably adequate in its ability to reach affected members of the public. Many states provide for notification of public engagement through the internet, however there cannot be a presumption that such notification is adequate in reaching all those who are impacted by a CAA section 111(d) state plan and would benefit the most from participating in a public hearing. For example, data shows that as many as 30 million Americans do not have access to broadband infrastructure that delivers even minimally sufficient speeds, and that 25 percent of adults ages 65 and older report never going online.²⁹⁵ Examples of prominent advertisement for a public hearing, in addition to through the internet, may include notice through newspapers, libraries, schools, hospitals, travel centers, community centers, places of worship, gas stations, convenience stores, casinos, smoke shops, Tribal Assistance for Needy Families offices, Indian Health Services, clinics, and/or other community health and social services as appropriate for the emission guideline addressed.

Given the public health and welfare objectives of CAA section 111(d) in regulating specific existing sources, the EPA believes it is reasonable to require meaningful engagement as part of the state plan development public participation process in order to further these objectives. Additionally, CAA section 301(a)(1) provides that the EPA is authorized to prescribe such regulations “as are necessary to carry out [its] functions under [the CAA].” The proposed meaningful engagement requirements would effectuate the EPA’s function under CAA section 111(d) in prescribing a process under which states submit plans to implement

the statutory directives of this section. Therefore, the EPA is proposing additional meaningful engagement requirements to ensure that pertinent stakeholders have reasonable notice of relevant information and the opportunity to participate in the state plan development throughout the process. The EPA intends to propose similar meaningful engagement provisions to this provision under the implementing regulations in a separate upcoming rulemaking that would apply generally to new EG promulgated under CAA section 111(d). While inviting comments on the application of these proposed revisions in the context of the oil and gas sector in this rulemaking, the EPA also encourages the public to provide comments on these proposed revisions more generally in that upcoming rulemaking process to amend the implementing regulations. The EPA intends to finalize that rulemaking before finalizing this oil and gas rulemaking.

Consistent with its intended addition to the implementing regulations, in this supplemental proposal, the EPA is proposing regulatory text for EG OOOOc in 40 CFR 60.5365c regarding the proposed meaningful engagement requirements that states must complete prior to the submittal of their state plans. In particular, the EPA is proposing to define meaningful engagement as “. . . timely engagement with pertinent stakeholder representation in the plan development or plan revision process. Such engagement must not be disproportionate nor favor certain stakeholders. It must include the development of public participation strategies to overcome linguistic, cultural, institutional, geographic, and other barriers to participation to assure pertinent stakeholder representation, recognizing that diverse constituencies may be present within any particular stakeholder community. It must include early outreach, sharing information, and soliciting input on the State plan.” The EPA is also proposing to define that pertinent stakeholders “. . . include, but are not limited to, industry, small businesses, and communities most affected by and/or vulnerable to the impacts of the plan or plan revision.” Increased vulnerability of communities may be attributable, among other reasons, to both an accumulation of negative and lack of positive environmental, health, economic, or social conditions within these populations or communities. Examples of such communities have historically included, but are not limited to,

communities of color (often referred to as “minority” communities), low-income communities, tribal and indigenous populations, and communities in the United States that potentially experience disproportionate health or environmental harms and risks as a result of greater vulnerability to environmental hazards. Tribal communities or communities in neighboring states may also be impacted by a state plan and, if so, should be identified as pertinent stakeholders. In addition, to the extent a designated facility would qualify for a less stringent standard through consideration of RULOF as described in section V.B.3.h of this preamble, the state, must identify and engage with the communities most affected by and vulnerable to the health and environmental impacts from the designated facility considered in a state plan for RULOF provisions. The EPA expects that the inclusion of the definitions of meaningful engagement and pertinent stakeholders in EG OOOOc will provide the states specificity around the meaningful engagement requirements while allowing for flexibility in the implementation of such requirements.

In the November 2021 proposal, the EPA proposed to include a requirement for a demonstration of meaningful engagement as part of the completeness evaluation of a state plan submittal. The EPA is proposing regulatory text associated to the proposed meaningful engagement demonstration states are to include in their plans as part of the completeness criteria. The EPA is proposing that a state would be required to provide, in their plan submittal, a list of the pertinent stakeholders and a summary of engagement conducted and of the stakeholder input provided. The EPA would evaluate the states’ demonstrations regarding meaningful engagement as part of its completeness evaluation of a state plan submittal. If a state plan submission does not include the required elements for public participation, including requirements for meaningful engagement, this may be grounds for the EPA to find the submission incomplete or to disapprove the plan. The EPA is soliciting comment on the proposed definitions of meaningful engagement and pertinent stakeholders as well as the inclusion of meaningful engagement requirements in completeness criteria for state plan submission. The EPA also solicits comments on examples or models of meaningful engagement by states, including best practices and challenges.

During the state plan process, the EPA expects states to identify the pertinent stakeholders. As part of efforts to ensure

²⁹⁴ Consistent with this principle of providing reasonable notice under the CAA, under programs other than CAA section 111(d), the EPA similarly requires states to provide specific notice to an area affected by a particular proposed action. *See e.g.*, 40 CFR 51.161(b)(1) requiring specific notice for an area affected by a state or local agency’s analysis of the effect on air quality in the context of the New Source Review program; 40 CFR 51.102(d)(2), (4), and (5) requiring specific notice for an area affected by a CAA section 110 SIP submission.

²⁹⁵ FACT SHEET: Biden-Harris Administration Mobilizes Resources to Connect Tribal Nations to Reliable, High-Speed internet (Dec. 22, 2021). <https://www.whitehouse.gov/briefing-room/statements-releases/2021/12/22/fact-sheet-biden-harris-administration-mobilizes-resources-to-connect-tribal-nations-to-reliable-high-speed-internet/>; 7% of Americans don’t use the internet. Who are they? Pew Research Center (Apr. 2, 2021), <https://www.pewresearch.org/fact-tank/2021/04/02/7-of-americans-dont-use-the-internet-who-are-they/>.

meaningful engagement, states will share information and solicit input on plan development and on any accompanying assessments. This engagement will help ensure that plans achieve the appropriate level of emission reductions, that communities most affected by and vulnerable to the health and environmental impacts from the designated facilities partake in the benefits of the state plan, and that these communities are protected from being adversely impacted by the plan. In addition, the EPA recognizes that emissions from designated facilities could cross state and/or Tribal borders, and therefore may affect communities in neighboring states or Tribal lands. The EPA expects that the discussion in section VI of the November 2021 proposal (86 FR 63139) will assist the states in the identification of pertinent stakeholders. The EPA is soliciting comment on how meaningful engagement should apply to pertinent stakeholders inside and outside of the borders of the state that is developing a state plan, for example, if a state should coordinate with the neighboring state and/or tribes for engagement or directly contact the affected communities.

The EPA further proposes to allow a state to request the approval of different state procedures for public participation. The EPA proposes to require that such alternate state procedures do not supersede the meaningful engagement requirements, so that a state would still be required to comply with the meaningful engagement requirements even if they apply for a different procedure than the other public notice and hearing requirements. The EPA is however also proposing that states may apply for, and the EPA may approve, alternate meaningful engagement procedures if, in the judgement of the Administrator, the procedures, although different from the requirements of this subpart, in fact provide for adequate notice to and meaningful engagement of the public. The EPA is soliciting comment on the distinction between request for approval of alternate state procedures to meet public notice and hearing requirements from those to meet meaningful engagement, and comment on the consideration of request for approval of alternate meaningful engagement procedures.

The EPA conducted meaningful engagement prior to the November 2021 proposal. The EPA believes this example will provide states with ideas for how they can structure their own meaningful engagement activities. States are not limited by the EPA's example, but rather the EPA's example should be

viewed as a minimum of what type of engagement is considered sufficient to meet the meaningful engagement requirement for purpose of state plan submittal.

Prior to the November 2021 proposal, the EPA identified stakeholder groups likely to be interested in the proposal and engaged with them in several ways including through meetings, training webinars, and public listening sessions to share information with stakeholders about this action, on how stakeholders may comment on the proposed rule, and to hear their input about the industry and its impacts as we were developing this proposal.²⁹⁶ Specifically, on May 27, 2021, the EPA held a webinar-based training designed for communities affected by this rule.²⁹⁷ This training provided an overview of the Crude Oil and Natural Gas Industry and how it is regulated and offered information on how to participate in the rulemaking process. The EPA also held virtual public listening sessions June 15 through June 17, 2021, and heard various community and health related themes from speakers who participated.²⁹⁸

In addition to the trainings and listening sessions, the EPA engaged with community leaders potentially impacted by this proposed action by hosting a meeting with EJ community leaders on May 14, 2021. The EPA provided the public with factual information to help them understand the issues addressed by the November 2021 proposal. We obtained input from the public, including communities, about their concerns about air pollution from the oil and gas industry, including receiving stakeholder perspectives on alternatives. The EPA considered and weighed information from communities as the agency developed the November 2021 proposal.

In addition to the engagement conducted prior to the November 2021 proposal, the EPA provided the public, including those communities disproportionately impacted by the burdens of pollution, opportunities to

engage in the EPA's public comment period for this proposal, including by hosting trainings on the proposed rule and a public hearing. EPA hosted three half-day trainings November 16 through 18, 2021, to provide background information, an overview of the proposed rule, stakeholder panel discussions, and information on how to effectively engage in the regulatory process. The trainings were open to the public, with a focus on communities with EJ concerns, Tribes and small business stakeholders. The public hearing occurred on November 30 to December 2, 2021, and the EPA requested speakers discuss:

- What impacts they are experiencing (i.e., health, noise, smells, economic),
- How the community would like the EPA to address their concerns,
- How the EPA is addressing those concerns in the rulemaking, and
- Any other topics, issues, concerns, etc. that the public may have regarding this proposal.

The EPA expects that the description of the meaningful engagement with pertinent stakeholders included in the preamble and in the docket of this rulemaking will serve as a guide of the meaningful engagement demonstration states are to include in their plans as part of the completeness criteria.

C. Components of State Plan Submission

While the EPA is not proposing any changes from the November 2021 proposal to this section, the EPA is proposing to add a provision for electronic submission of state plans. The provision at 40 CFR 60.23a(a)(1) currently requires state plan submissions to be made in accordance with the provision in 40 CFR 60.4. Pursuant to 40 CFR 60.4(a), all requests, reports, applications, submittals, and other communications to the Administrator pursuant to 40 CFR part 60 shall be submitted in duplicate to the appropriate Regional Office of the EPA. The provision in 40 CFR 60.4(a) then proceeds to include a list of the corresponding addresses for each Regional Office. In this supplemental proposal, the EPA is proposing to require electronic submission of state plans instead of paper copies as according to 40 CFR 60.4. In particular, the EPA is proposing to include a sentence in 40 CFR 60.5362c(a) that reads as follows: "The submission of such plan shall be made in electronic format according with 40 CFR 60.5362c(d) of this subpart." In 40 CFR 60.5362c(d), the EPA is proposing the requirements associated with the electronic submittal of plans.

²⁹⁶ For more information about the EPA's pre-proposal outreach activities, please see EPA Docket ID No. EPA-HQ-OAR-2021-0295 and EPA-HQ-OAR-2021-0317. For a description of the themes that commenters raised please see the 2021 November proposal at 86 FR 63143.

²⁹⁷ https://www.epa.gov/sites/default/files/2021-05/documents/us_epa_training_webinar_on_oil_and_natural_gas_for_communities.5.27.2021.pdf.

²⁹⁸ June 15, 2021 session: <https://youtu.be/T8XwDbf-B8g>; June 16, 2021. session: <https://www.youtube.com/watch?v=l23bKPF-5oc>; June 17, 2021 session: <https://www.youtube.com/watch?v=R2AZrmfuAXQ>.

²⁹⁹ Full transcripts for the listening sessions are posted at EPA Docket ID No. EPA-HQ-OAR-2021-0295.

As previously described, CAA section 111(d) requires the EPA to promulgate a “procedure” similar to that of CAA section 110 under which states submit plans. The statute does not prescribe a specific platform for plan submissions, and the EPA reasonably interprets the procedure it must promulgate under the statute as allowing it to require electronic submission. Requiring electronic submission is reasonable for the following reasons. Providing for electronic submittal of CAA section 111(d) state plans in EG OOOOc in place of paper submittals aligns with current trends in electronic data management and will result in less burden on the states. It is the EPA’s experience that the electronic submittal of information increases the ease and efficiency of data submittal and data accessibility. The EPA’s experience with the electronic submittal process for SIPs under CAA section 110 has been successful as all the states are now using the State Planning Electronic Collaboration System (SPeCS). SPeCS is a user-friendly, web-based system that enables state air agencies to officially submit SIPs and associated information electronically for review and approval to meet their CAA obligations related to attaining and maintaining the NAAQS. SPeCS is the EPA’s preferred method for receiving such SIPs submissions. The EPA has worked extensively with state air agency representatives and partnered with E-Enterprise for the Environment and the Environmental Council of the States to develop this integrated electronic submission, review, and tracking system for SIPs. SPeCS can be accessed by the states through the CDX. The CDX is the Agency’s electronic reporting site and performs functions for receiving acceptable data in various formats. The CDX registration site supports the requirements and procedures set forth under the EPA’s Cross-Media Electronic Reporting Regulation, 40 CFR part 3.

The EPA is proposing to include the requirements associated with the electronic submittal of a state plan in EG OOOOc. As proposed, EG OOOOc will require state plan submission to the EPA be via the use of SPeCS or through an analogous electronic reporting tool provided by the EPA for the submission of any plan required by this subpart. The EPA is also proposing to include language to specify that states are not to transmit CBI through SPeCS. Even though state plans submitted to the EPA for review and approval pursuant to CAA section 111(d) through SPeCS are not to contain CBI, this language will also address the submittal of CBI in the

event there is a need for such information to be submitted to the EPA. The requirements for electronic submission of CAA section 111(d) state plans in EG OOOOc will ensure that these Federal records are created, retained, and maintained in electronic format. Electronic submittal will also improve the Agency’s efficiency and effectiveness in the receipt and review of state plans. The electronic submittal of state plans may also provide continuity in the event of a disaster like the one our nation experienced with COVID–19. The EPA requests comment on whether the EPA should provide for electronic submittals of plans as an option instead of as a requirement. The EPA requests comment on whether a requirement for electronic submissions of CAA section 111(d) state plans should be via SPeCS or whether another electronic mechanism should be considered as appropriate for CAA section 111(d) state plan submittals.

D. Timing of State Plan Submissions and Compliance Times

Background and Court Decision Re: Vacated Timelines. Under CAA section 111(d), it is first the EPA’s responsibility to establish a BSER and a presumptive level of stringency via a promulgated EG. It is then each state’s obligation to submit a plan to the EPA that establishes standards of performance for each designated facility. The EPA acknowledged in the November 2021 proposal that the D.C. Circuit vacated certain timing provisions within 40 CFR part 60, subpart Ba. *Am. Lung Assoc. v. EPA*, 985 F.3d at 991 (D.C. Cir. 2021) (ALA). See 86 FR 63255 (November 15, 2021). These vacated timing requirements include: the timeline for state plan submissions, the timeline for the EPA to act on a state plan, the timeline for the EPA to promulgate a Federal plan, and the timeline that dictates when state plans must include increments of progress. As a result of the court’s vacatur, no regulations currently govern the timing of these actions for EGs promulgated after July 8, 2019.³⁰⁰ The Agency plans to undertake a separate rulemaking to address these vacated provisions in subpart Ba for purposes of the implementing regulations, including a generally applicable deadline for state plan submissions. However, the EPA solicited comment in the November 2021 proposal on any facts and circumstances that are unique to the oil and natural gas industry that the EPA should consider when proposing a

timeline for plan submission applicable to a final EG for this source category. The EPA is now proposing to require that each state adopt and submit to the Administrator, within 18 months after publication of the final EG OOOOc, a plan for the control of GHGs in the form of limitations on methane to which EG OOOOc applies. As described further in this section, an 18-month deadline for state plans addressing EG OOOOc both appropriately accommodates the process required by states to develop plans to effectuate the EG OOOOc, and is consistent with the objective of CAA section 111(d) to ensure that designated facilities control emissions of GHGs that the EPA has determined may be reasonably anticipated to endanger public health or welfare.

The EPA notes that the portions of the implementing regulations under subpart Ba that were not affected by the court’s vacatur, the November 2021 proposal, and this supplemental proposal collectively lay out all of the required components of, and requirements for, state plans for purposes of EG OOOOc. Therefore, states will have the necessary information at that time to develop state plans to meet the requirements of any final EG OOOOc. Any separate rulemaking to address the vacated provisions in subpart Ba will not add to or change these required components. The EPA intends to propose deadlines for its action on state plan submissions and for promulgation of a Federal plan in its separate rulemaking. These deadlines are intended to apply generally to these actions implementing EGs under CAA section 111(d), including to the EPA’s action on state plan submissions and promulgation of a Federal plan under the final EG OOOOc. It is not necessary for the EPA to propose deadlines on its own action on state plans submitted in response to a final EG OOOOc, or promulgation of a Federal plan where a state fails to submit an approvable plan, as part of this supplemental proposal because these deadlines are not relevant to states in the development of their plans, and go to the EPA’s actions subsequent to the states’ development of their plans. However, the EPA intends to propose and finalize these deadlines not later than finalization of an EG OOOOc, so that states and stakeholders will have knowledge of them as development on state plans begins. Additionally, as described further in this section, the EPA is proposing the final compliance schedule for designated facilities to run from the deadline for state plan submissions. Accordingly, the compliance deadline for any final EG

³⁰⁰ The court did not vacate the applicability provision for subpart Ba under 40 CFR 60.20a(a).

OOOOC will also be knowable and provide certainty of obligations to regulated entities and other stakeholders in advance of state plan development. The D.C. Circuit's vacatur of the extended timelines in subpart Ba was based both on the EPA's failure to substantiate the necessity for the additional time at each step of the administrative process, and the EPA's failure to address how those extended implementation timelines would impact public health and welfare. Accordingly, for EG OOOOC, the EPA has evaluated these factors and is proposing the 18-month state plan deadline based on the minimum administrative time reasonably necessary for each step in the implementation process thus, minimizing impacts on public health and welfare. This approach addresses both aspects of the *ALA* decision because states will take no longer than necessary to develop and adopt plans that impose requirements consistent with the overall objectives of CAA section 111(d).

The EPA acknowledges this proposed 18-month deadline is not identical to the generally applicable three year-deadline for SIPs under CAA section 110, which the agency adopted in the vacated subpart Ba rule. However, the EPA's proposed deadline is consistent with the requirement of CAA section 111(d) that the EPA to promulgate a procedure "similar" to that of CAA section 110, rather than an identical procedure. This is also consistent with the *ALA* decision, which requires the EPA to "engage meaningfully with the different scale" of CAA section 111(d) and 110 plans. *Am. Lung Ass'n v. EPA*, 985 F.3d 914, 993 (D.C. Cir. 2021). Accordingly, the EPA evaluated each step of the OOOOC implementation process to independently determine the appropriate duration of time to accomplish the given step as part of the overall process, and the proposed timeline represents what the EPA is proposing to determine will be necessary for a state plan upon publication of any final EG OOOOC.

As described previously, no timing requirements for state plan submissions are currently in effect for EGs published after July 8, 2019. The original implementing regulations promulgated under subpart B in 1975, which are applicable to EGs published before July 8, 2019, provide that states have nine months to submit a state plan after publication of a final EG. 40 CFR 60.23(a)(1). In 2019, the EPA promulgated subpart Ba and provided three years for states to submit plans, consistent with the timelines provided for submission of SIPs pursuant to CAA

section 110(a)(1). This 3-year timeframe was vacated in the *ALA* decision, and thus currently there is no applicable deadline for state plan submissions required under EGs subject to subpart Ba. In evaluating the appropriate timeline for plan submittal to propose for EG OOOOC, the EPA reviewed steps that states need to carry out to develop, adopt, and submit a state plan to the EPA, and its history in implementing EGs under the timing provisions of subpart B. The EPA further evaluated statutory deadlines, contents, and processes for relatively comparable state plans under CAA sections 129 and 182. The EPA also considered the characteristics of the Crude Oil and Natural Gas source category to assist justification for the timelines and address how the timeline will impact health and welfare.

In developing a CAA section 111(d) state plan, a state must consider multiple components in meeting applicable requirements. In addition to any requirements that an EG specifies for state plans, subpart Ba specifies certain fundamental elements that must be included in a state plan submission (see 40 CFR 60.24a, 60.25a, 60.26a) and certain processes that a state plan must undergo in adopting and submitting a plan (see 40 CFR 60.23a). In addition to these EPA requirements for state plans, there are also state-specific processes applicable to the development and adoption of a state plan. In particular, the component that the EPA expects to take the most time and have the most variability from state to state is the administrative process (*e.g.*, through legislative processes, regulation, or permits) that establishes standards of performance. Considering this variability, 18 months should adequately accommodate the differences in state processes necessary for the development of a state plan that meets applicable requirements. The EPA evaluated data from previously implemented EGs, and the statutory deadlines and data from analogous programs (*i.e.*, CAA section 129), as described below, to help inform this proposed 18-month timeline.

Subpart B provides nine months for states to submit plans after publication of a final EG. The EPA's review of state's timeliness for submitting CAA section 111(d) plans under the 9-month timeline indicates that most states either did not submit plans or submitted plans that were substantially late. We note that the plans submitted under subpart B were not subject to the additional requirements the EPA is proposing for meaningful engagement and consideration of RULOF, respectively

described in section V.B. Based on the lack of timeliness of prior state plan submissions under subpart B and the additional requirements of this proposal, EG OOOOC, nine months is not a suitable amount of time for most states to adequately develop a plan for an EG.

To help inform what is an appropriate proposal for the state plan submission deadline, the EPA also reviewed CAA section 129's statutory deadline and requirements for state plans, and the timeliness and responsiveness of states under CAA section 129 EGs. CAA section 129 references CAA section 111(d) in many instances, creating considerable overlap in the functionality of the programs. Notably, existing solid waste incineration units are subject to the requirements of both CAA sections 129 and 111(d). CAA section 129(b)(1). The processes for CAA sections 111(d) and 129 are very similar in that states are required to submit plans to implement and enforce the EPA's EGs. However, there are some key distinctions between the two programs, most notably that CAA section 129(b)(2) specifies that state plans be submitted no later than 1 year from the promulgation of a corresponding EG, whereas the statute does not specify a particular timeline for state plan submissions under CAA section 111(d) and is instead governed by the EPA's implementing regulations (*i.e.*, subparts B and Ba). Moreover, CAA section 129 plans are required by statute to be at least as protective as the EPA's EGs. However, CAA section 111(d) permits states to take into account remaining useful life and other factors, which suggests that the development of a CAA section 111(d) plan could involve more complicated analyses than a CAA section 129 plan (see section V.B. for more information on RULOF provisions). The contrast between the CAA section 129 plans and CAA section 111(d) plans suggests that in determining the timeframe for CAA section 111(d) plan submissions the EPA should provide for a longer timeframe than the 1 year timeframe the statute provides under CAA section 129.

The EPA found that a considerable number of states have not made required state plan submissions in response to a CAA section 129 EG. In instances where states submitted CAA section 129 plans, a significant number of states submitted plans between 14 to 17 months after the promulgated EG. This suggests that states will typically need more than 1 year to develop a state plan to implement an EG, particularly for a program that permits more source-

specific analysis than under CAA section 129 as CAA section 111(d) does.

In the 2019 promulgation of subpart Ba, the EPA mirrored CAA section 110 by giving states 3 years to submit plans. As previously described, the court partly faulted the EPA for adopting the CAA section 110 timelines without accounting for the differences in scale and scope between CAA section 110 and 111(d) plans. The EPA has now more closely evaluated the statutory deadlines and requirements in the CAA section 110 implementation context to determine what might be feasible for an OOOOc EG state plan submission timeline. The EPA specifically focused on statutory SIP submission deadline and requirements in the context of attainment plans for the ozone NAAQS. Subpart 2 of Title I of the CAA contains a number of deadlines for ozone attainment plans that are 2 years or longer. For example, areas initially designated Marginal have two years from designation to submit a SIP that contains a permitting program and emissions inventory. CAA section 182(a). Areas initially designated Moderate have two years to submit a plan implementing reasonable available control technologies under CAA section 182(b)(2)), and three years to submit their attainment plan and other requirements under CAA section 182(b)(1). These ozone attainment plans are arguably more complicated for states to develop when compared to plans under CAA section 111(d) for EG OOOOc. For example, ozone attainment plans require states to determine how to control a variety of sources, based on extensive modeling and analyses, in order to bring a nonattainment area into attainment of the NAAQS by a specified attainment date. Under CAA section 111(d) and EG OOOOc, it is clear which designated facilities must be subject to a state plan, and the standards of performance for these sources must generally reflect the level of stringency determined by the EG unless a state chooses to account for RULOF. Additionally, ozone attainment plans must contain inventories of actual emissions from certain sources, whereas the EPA is proposing to supersede the subpart Ba inventory requirement for purposes of this EG. The difference in complexity between the CAA ozone attainment plan requirements and the plan requirements for EG OOOOc suggests that a timeline of 18 months is more appropriate for developing state plans submissions in response to this EG.

Furthermore, the EPA considered the characteristics of the Crude Oil and Natural Gas source category. The EPA

believes that EG OOOOc has the potential to require states to perform considerable engineering and/or economic analyses for their plan. For example, the EPA anticipates considerable engineering analyses for when states chose to leverage their existing state programs and determine that their existing state program meets the criteria to conduct a source-by-source stringency comparison. The engineering analysis can become more complex should a state chooses to utilize a different design, equipment, work practice, and/or operational standard than the EG because a qualitative assessment will have a number of metrics that require evaluation. The EPA also anticipates states will need to conduct considerable engineering and economic analysis should a state invoke RULOF. As discussed in section V.C., when invoking RULOF, the plan submission must identify all control technologies available for the source and evaluate the BSER factors for each technology, using the same metrics and evaluating them in the same manner as the EPA did in developing the EG. For example, if the EPA considered capital cost as part of the BSER analysis, the state will also need to consider the same.

The EPA has long recognized the unique nature of the Crude Oil and Natural Gas source category because, in comparison to other EG, it is geographically spread out covering multiple industry segments. Specifically, the EPA defines the Crude Oil and Natural Gas source category to mean: (1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and (2) natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.³⁰¹ The Crude Oil and Natural Gas source category impacts a great number of states, tribes, and U.S. territories in some capacity. U.S. Energy Information Administration (EIA) production data shows thirty-four states that have crude oil and or natural gas production.³⁰² Except for Vermont and Hawaii, the

states not producing crude oil and or natural gas have compressor stations in the transmission and storage segment. The EPA understands that EG OOOOc for the Crude Oil and Natural Gas source category will apply to an extraordinary number of designated facilities and for many designated facilities the standards are complex compared to other EG. For example, in the U.S., the EPA has identified over 15,000 oil and gas owners and operators, around 1 million producing onshore oil and gas wells, about 5,000 gathering and boosting facilities, over 650 natural gas processing facilities, and about 1,400 transmission compression facilities. States will need to develop and draft plans covering these designated facilities that include the required components, such as standards of performance and implementation measures for such standards, and adopt the plans through their required administrative processes before submitting them to the EPA. EG OOOOc covers numerous designated facilities with corresponding presumptive standards. By comparison, the EPA's EG for Municipal Solid Waste Landfills included one designated facility type, affecting approximately 1,000 landfills. 81 FR 59313 (August 29, 2016). Of these 1,000 landfills, approximately 731 will be affected by the collection and control standard laid out in the rule, approximately 93 more landfills than the 1996 Municipal Solid Waste Landfills EG. 61 FR 9919 (March 12, 1996).

The EPA also recognizes the need to address potential health and welfare impacts of methane emissions from this source category. The EPA discusses extensively in section III of the November 2021 proposal³⁰³ titled, "Air Emissions from the Crude Oil and Natural Gas Sector and Public Health and Welfare," and in section VI of the November 2021 proposal titled, "Environmental Justice Considerations, Implications, and Stakeholder Outreach," the urgent need to mitigate climate-destabilizing pollution and protecting human health by reducing GHG emissions from the Oil and Natural Gas Industry,³⁰⁴ specifically, the Crude Oil and Natural Gas source category.³⁰⁵

³⁰³ See 86 FR 63110 (November 15, 2021).

³⁰⁴ The EPA characterizes the Oil and Natural Gas Industry operations as being generally composed of four segments: (1) Extraction and production of crude oil and natural gas ("oil and natural gas production"), (2) natural gas processing, (3) natural gas transmission and storage, and (4) natural gas distribution.

³⁰⁵ The EPA defines the Crude Oil and Natural Gas source category to mean: (1) Crude oil production, which includes the well and extends to

³⁰¹ For purposes of the November 2021 proposal and this supplemental proposed rulemaking, for crude oil, the EPA's focus is on operations from the well to the point of custody transfer at a petroleum refinery, while for natural gas, the focus is on all operations from the well to the local distribution company custody transfer station commonly referred to as the "city-gate".

³⁰² See https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbldpd_a.htm and https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPGO_FGW_mmcfa.htm.

The Oil and Natural Gas Industry is the United States' largest industrial emitter of methane, a highly potent GHG. Human activity-related emissions of methane are responsible for about one third of the warming due to well-mixed GHGs and constitute the second most important warming agent arising from human activity after carbon dioxide (a well-mixed gas is one with an atmospheric lifetime longer than a year or two, which allows the gas to be mixed around the world, meaning that the location of emission of the gas has little importance in terms of its impacts). According to the Intergovernmental Panel on Climate Change (IPCC), strong, rapid, and sustained methane reductions are critical to reducing near-term disruption of the climate system and are a vital complement to reductions in other GHGs that are needed to limit the long-term extent of climate change and its destructive impacts. The need to balance the complexity of EG OOOOc and the need to mitigate climate change and protecting human health further suggest that a timeline of 18 months is more appropriate for development of state plans submissions.

Thus, based on the EPA's evaluation of states' responsiveness to previous CAA section 111(d) EGs, the contrast between the development of CAA section 111(d) plans and CAA section 129 plans, the complexity of the source category and designated facilities, and the need to quickly take action to address critical climate and health and welfare impacts, the EPA is proposing to require that state plans under EG OOOOc be due 18 months after publication of the final EG. This proposed timeframe is substantially shorter than the 3-year deadline vacated by the D.C. Circuit; however, it should give states adequate time to adopt and submit approvable plans without extending the timing such that significant adverse impacts to health and welfare are likely to occur from the foregone emission reductions during the state planning process. Allowing states sufficient time to develop feasible implementation plans for their designated facilities that adequately

address public health and environmental objectives will ultimately help ensure timelier implementation of EG OOOOc, and therefore achievement in actual emission reductions, than would an unattainable deadline that may result in the failure of states to submit plans and require the development and implementation of a Federal plan.

The EPA recognizes that the court, in *ALA*, faulted the Agency for failing to consider the potential impacts to public health and welfare associated with extending planning deadlines. The EPA does not interpret the court's direction to require a quantitative measure of impact, but rather consideration of the importance of the public health and welfare goals when determining appropriate deadlines for implementation of regulations under CAA section 111(d). Because 18 months is the minimum period of time in which the EPA finds that most states can expeditiously create and submit a plan that meets applicable requirements for EG OOOOc, it follows that the EPA has appropriately considered the potential impacts to public health and welfare associated with this extension of time by providing no more time than the states reasonably need to ensure a plan is comprehensive and timely. The EPA is soliciting comment on the proposed 18-month state plan submission deadline upon publication of the final EG OOOOc, and the analysis supporting the EPA's proposed determination regarding the amount of time reasonably necessary for plan development and submission. The EPA is also soliciting comment on whether the EPA should consider any other factors in setting this deadline.

As discussed in section V.B of this preamble, the EPA is proposing to include a requirement for states to undertake outreach and meaningful engagement with pertinent stakeholders as part of the state plan development process. The EPA solicits comment on how much, if any, time this additional engagement will take in the state plan development process.

In section V.B of this preamble, the EPA is also proposing revisions to the RULOF provision. These proposed revisions would clarify the procedures for considering RULOF by establishing a robust analytical framework that would require a state to provide a sufficient justification when applying a standard of performance that is less stringent than the EPA's presumptive level of stringency, thereby allowing the EPA to readily determine if the state's plan is satisfactory and therefore approvable. The proposed state plan

submission timeline of 18 months should adequately provide time for states to conduct the analyses required by this provision; however, the EPA is soliciting comment on whether states will need additional time in the plan development to account for instances where RULOF is considered. The EPA is specifically requesting comment on how much additional time might be required for this consideration and how that additional time fits within the entire process of state plan development.

The proposed state plan submission timeline should be generally achievable by states. The EPA notes it is obligated to promulgate a Federal plan for states that have not submitted a plan by the submission deadline. Once the obligation to promulgate a Federal plan is triggered, it can only be tolled by the EPA's approval of a state plan. If a Federal plan is promulgated, a state may still submit a plan to replace the Federal plan. A Federal plan under CAA section 111(d) is a means to ensure timely implementation of EGs, and a state may choose to accept a Federal plan for their sources rather than submit a state plan. While the EPA encourages states to timely submit plans, there are no mandatory sanctions associated with submitting a late plan or accepting the implementation of a Federal plan.

Timeline for State Plan Compliance Schedule. Under 40 CFR 60.22a(b)(5), the EPA in an EG is required to provide, among other things, "the time within which compliance with standards of performance can be achieved". Each state plan must then include compliance schedules that, subject to certain exception, require compliance as expeditiously as practicable but no later than the compliance times included in the relevant EG. *Id.* at 60.24a(a) and (c). States are free to include compliance times in their plans that are earlier than those included in the final EG. *Id.* at 40 CFR 60.24a(f)(2). If a state chooses to include a compliance schedule in its plan that extends for a certain period beyond the date required for submittal of the plan, then "the plan must include legally enforceable increments of progress to achieve compliance for each designated facility." 341 *Id.* at 40 CFR 60.24a(d). To the extent a state accounts for remaining useful life and other factors in applying a less stringent standard of performance than required by the EPA in the final EG, the state must also include a compliance deadline that it can demonstrate appropriately correlates with that standard.

The November 2021 proposal proposed requiring that state plans impose a compliance timeline on

the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and (2) natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station. For purposes of this proposed rulemaking, for crude oil, the EPA's focus is on operations from the well to the point of custody transfer at a petroleum refinery, while for natural gas, the focus is on all operations from the well to the local distribution company custody transfer station commonly referred to as the "city-gate".

designated facilities to require final compliance with the standards of performance as expeditiously as practicable, but no later than 2 years following the state plan submittal deadline. 86 FR 63256 (November 15, 2021). Commenters on the proposal indicated that more than 2 years after the submittal of a state plan was needed to come into compliance for existing sources. Given the number of designated facilities that would need to come into compliance, commenters explained that requiring existing sources to upgrade at the same time would place a substantial burden on the supply chain (all orders at the same time) and vendors (all

install at the same time). Commenters stated that, if compliance timelines are too short, there will be significant economic disruptions for both the companies operating these facilities as well as the manufacturers who support them. Commenters also stated that there would be a need to train a tremendous number of staff on the regulatory requirements and actions needed to comply. A few of the commenters representing states also noted that 2 years from state plan submittal would not allow sufficient time for states to issue the air quality permits in advance of the compliance date for the sources to have regulatory requirements with

which to demonstrate compliance. Environmental commenters supported the EPA's proposed requirement that state plans include a compliance timeline within no more than 2 years of plan submission and urged the Agency to consider whether a more abbreviated compliance timeline is warranted.³⁰⁶

In evaluating whether to revise the November 2021 proposed two-year final compliance deadline, the EPA considered several factors that could impact the ability of a designated facility to come into compliance with the proposed presumptive standards. These factors are presented in Table 38.

TABLE 38—FACTORS CONSIDERED WHEN DETERMINING COMPLIANCE TIMELINE

Factor	Description
Design/Purchase Equipment	Equipment must be purchased and installed to comply. This could be control equipment or specific equipment to meet an equipment standard (e.g., solar powered pneumatic controller). This would also typically involve design considerations.
Availability of Equipment (Supply Chain Issues)	This factor is related to the potential shortage of available equipment. Note that this could have an impact on small businesses as the assumption is that larger businesses would be supplied first.
Cost of Equipment (Individual Designated Facility)	The cost of equipment for an individual designated facility. This cost may disproportionately impact small businesses.
Performance Testing	The requirement for a performance testing requires securing the services of a testing contractor, scheduling and planning the test, and notifying/coordinating with the state agency. In addition to control device performance testing, this would also include monitoring (e.g., fugitive component monitoring).
Complexity of Requirements	More complex requirements may need more time for owners and operators to understand the requirements and develop procedures up-front to ensure initial and continuing compliance.
Availability of Specialized Services (Monitoring)	This is related to the potential shortage of available specialized services (e.g., OGI contractors). Note that this could have an impact on small businesses as the assumption is that contractors could prioritize larger businesses.
Number of Designated Facilities	The sheer number of designated facilities may have an impact on the ability to comply within a specified timeline, which assumes that it will potentially be more problematic for companies owning many designated facilities to comply in a shorter time frame.
Existing Sources Covered by State Regulation	If the designated facility is covered by state regulations that cover existing sources to a degree equivalent to the EG, the number of designated facilities needing to comply with be less.
Emissions Reduced/Total Designated Facility	The overall methane emissions reduction that will result from control of existing sources under the EG. EPA could prioritize designated facilities to achieve emission reductions sooner.

Some of the factors presented in Table 38 would impact the ability of an owner or operator of a designated facility to comply within two years more than others. For example, factors that are beyond an owner or operator's control, such as the availability of specialized services and availability of equipment, can be compounded by the fact that there are a large number of designated facilities where owners or operators are dependent on the availability of equipment and services. Other factors,

such as the cost of equipment necessary for a designated facility to come into compliance, will impact some owners and operators more than others. Small businesses have often reported that large businesses generally have an advantage over small businesses in such cases. Presumptive standards that include a higher reliance on factors that would impact the ability of a designated facility to come into compliance, such as those proposed for pneumatic controllers, were considered to require

more time (i.e., greater than the November 2021 proposed 2-year time frame). For example, to meet the proposed presumptive standards for pneumatic controllers, it is expected that more time may be needed due to the anticipated high demand for specialized equipment to meet the proposed EG standards and the increased reliance on "design/purchase equipment", "availability of equipment", "cost of equipment," and "number of designated facilities." Other

³⁰⁶ See Document ID No. EPA-HQ-OAR-2021-0317-0844.

designated facility presumptive standards that are less dependent on the need for specialized equipment or services (e.g., fugitive emissions work practice standards) might require less time to come into compliance than pneumatic controllers but would still require considerable upfront planning based on the number of designated facilities.

After consideration of comments received on the November 2021 proposal and consideration of the factors that could impact the ability of a designated facility to come into compliance with the proposed presumptive standards, the EPA is proposing to require that state plans impose a compliance timeline on designated facilities to require final compliance with the standards of performance as expeditiously as practicable, but no later than 36 months following the state plan submittal deadline. The EPA considered requiring differing compliance timelines for the differing designated facilities depending on the requirements of the proposed presumptive standards and the factors presented in Table 38 but chose to include a uniform compliance timeframe for all of the designated facilities. The EPA believes that establishing a uniform compliance timeline of no later than 36 months following the state plan submittal deadline simplifies compliance and eases the burden on large and small business owners and operators that need to develop and implement plans to meet their compliance obligations for a large number of designated facilities. The required state plan compliance elements for owners and operators to come into compliance include the need to: (1) Become familiar with state plan requirements for the nine different types of designated facilities, (2) assess all existing sites and operations owned by the company to determine the universe of designated facilities that are subject to requirements, (3) prepare an increment of progress final control compliance plan for meeting standards of performance for all of the hundreds, potentially thousands, of designated facilities owned by the company, (4) implement a compliance plan for each designated facility, (5) ensure standards of performance for designated facility are met by required compliance dates, and (6) plan and implement initial compliance performance testing, monitoring, recordkeeping, and reporting. Each of the nine types of designated facilities include various compliance element needs (e.g., engineering assessments, requirements

to purchase equipment, contract services for modifying existing equipment to include add-on control equipment, contract services to perform monitoring and/or performance testing, contract services to perform maintenance and repair services to ensure compliance).

The level of planning and implementation of a plan to come into compliance will differ by each type of designated facility. Further, site-specific conditions may require different compliance paths even for the same type of designated facility. Another factor to consider is the ability of an owner or operator to meet the initial capital and labor expenditures needed to develop and implement a compliance plan will vary based on the numbers of each of the designated facilities and available capital and in-house expertise/labor. Small businesses often need more time to absorb the associated capital and labor expenditure needs to develop and implement compliance plans. By allowing a uniform compliance deadline of 36 months from the time of submittal of the state plan to come into compliance, owners and operators are able to take into consideration all of the differing designated facilities, sites and expenditures that will be needed to comply when they develop their compliance plans. This will also reduce any potential confusion that could occur with varied compliance deadlines for designated facilities that are covered under the proposed EG.

As previously described, EPA is proposing to require that states submit their state plan within 18 months of publication of the EGs. Accordingly, linking a 36-month compliance deadline to the state plan submittal deadline for purposes of this EG would give sources ample time to plan for compliance with an approved state plan. The EPA also notes that publication of a final EG will also give sources meaningful information as to their potential compliance obligations, such as the presumptive standards, in advance of the state plan submittal deadline. Though EPA has not yet proposed a timeline for its action on state plans in response to the *ALA* vacatur, and intends to do so in an upcoming rulemaking, such timeline cannot be so lengthy as to contravene the court's direction to consider potential health and welfare impacts of an extended deadline. The EPA believes that a compliance deadline 36 months from the state plan submittal deadline is an appropriate amount of time for designated facilities to ensure compliance based on the EPA's general understanding of the industry and the

proposed presumptive standards and accounts for retrofit considerations and potential supply chain issues that owners and operators may encounter. The EPA considered whether to link the compliance deadline to its approval of a state plan, however, requiring compliance with state plans based on the state plan submittal deadline rather than the state plan approval date standardizes when designated facilities must come into compliance across states.

Subpart Ba requires that standards of performance are implemented in a timely manner through provisions that require legally enforceable increments of progress if the compliance schedule extends beyond 24 months after the state plan submission deadline.³⁰⁷ However, the 24-month timeline for triggering increments of progress was vacated by the D.C. Circuit in the *ALA* decision. Petitioners did not challenge, and the court did not vacate, the substantive requirement for increments of progress. The EPA intends to address the vacated timeline for increments of progress for purposes of the implementing regulations in an upcoming rulemaking. For EG OOOOc, because the EPA is proposing a final compliance deadline of 36 months after publication of the EG, the EPA is proposing to require that state plans must include legally enforceable increments of progress in order to better assure compliance by each designated facility or category of facilities. While the EPA is proposing 36 months after the state plan submission deadline for final compliance based on the considerations described above, increments of progress will help assure that designated facilities are on track to actually achieve compliance by undertaking certain concrete interim steps. Taking into consideration the large numbers of designated facilities that regulated entities would need to evaluate and plan for to come into compliance, we are proposing that state plans require owners and operators of designated facilities address two of the five incremental of progress steps identified in the definition of increments of progress subpart Ba: (1) A final control plan and (2) final compliance. The EPA is proposing that the final control plan include a compliance plan for each designated facility, but a company would be allowed to submit one plan that covers all of the company's designated facilities in the state in lieu of submitting a plan for each designated facility. The final control plan would be

³⁰⁷ 40 CFR 60.24a(a) and 60.24a(d).

required to include an identification of their designated facilities and how they are planning to comply with the EGs for each of their designated facilities (e.g., air pollution control devices/measures to be used to comply with the emission limits, standards and other requirements). The final control plan would also be required to include all instances where a designated facility is complying with an alternative standard (e.g., routing centrifugal compressor wet seal emissions to a control device to achieve a 95 percent reduction in methane instead of complying with the 3 scfm volumetric flow rate standard) or when the owner or operator is planning to claim technical infeasibility to allow compliance with an alternative standard (e.g., a pneumatic pump that demonstrates it is technically infeasible to use a pump that is not driven by natural gas and that is technically infeasible to route to control). We are proposing that the final control plan be required to be submitted within two years after the deadline for the state plan submittals. This timeline allows sufficient time for regulated entities to develop their compliance plan for each of their designated facilities to meet their compliance obligations. The EPA solicits comment on the timing and requirements of this final control plan proposal.

In addition to the final control plan, we evaluated whether to require a report that demonstrates final compliance as an increment of progress report. We are proposing that state plans include a requirement for owners and operators of designated facilities to submit a notification of final compliance report for each designated facility on or before 60 days after the compliance date of the state plan. Under this proposal, a company would be allowed to submit one notification that covers all of the company's designated facilities in a state in lieu of submitting a notification for each designated facility. As an alternative, we evaluated not including a specific requirement for a notification of final compliance report. Without a requirement for a notification of final compliance report, confirmation that designated facilities are complying with a state plan would not occur until the first annual report. The EPA determined that requiring a notification of final compliance report that was submitted before the first annual report was more closely aligned with the intent of a final compliance increment of progress step. The EPA solicits comment on this proposed notification of final compliance report.

VI. Use of Optical Gas Imaging in Leak Detection (Appendix K)

A. Overview of the November 2021 Proposal

In the November 2021 proposal, the EPA proposed a protocol for the use of OGI in the determination of leaks as Appendix K. The protocol was proposed for use in the oil and gas sector but was proposed to have broader applicability to surveys of process equipment using OGI cameras throughout the entire oil and gas upstream and downstream sectors from production through refining to distribution where a subpart in those sectors references its use.

The proposed appendix K was based on extensive literature review on the technology development, as well as observations on current applications of OGI technology, multiple empirical laboratory studies and OGI technology evaluations commissioned by the EPA, and a virtual stakeholder workshop hosted by the EPA to gather input on development of a protocol for the use of OGI. The proposed appendix K outlined the procedures that camera operators would be required to follow to identify leaks or fugitive emissions using a field portable infrared camera. Additionally, the proposed appendix K contained specifications relating to the required performance of OGI cameras, required operator training and verification, determination of an operating window for performing surveys, and requirements for a monitoring plan and recordkeeping.

B. Significant Changes Since Proposal

1. Scope

The EPA proposed that appendix K would have broad applicability across the oil and gas upstream and downstream sectors, but that it must be referenced by an applicable subpart before it would apply. This would potentially include well sites, compressor stations, boosting stations, petroleum refineries, gas processing plants, and gasoline distribution facilities. Chemical plants and other facilities outside of the oil and gas upstream and downstream sectors were specifically excluded in the applicability section.

Commenters stated that appendix K applicability should not be restricted to the oil and gas upstream and downstream sectors.³⁰⁸ While the EPA originally excluded the chemical sector because there are issues with seeing

some of the compounds that could be released as emissions in some of the chemical sector sources, there are some chemical sector sources where most of the emissions are made up of compounds that can be imaged by an OGI camera. As such, the EPA is proposing to revise the scope and applicability for appendix K to remove the sector applicability and to base the applicability on being able to image most of the compounds in the gaseous emissions from the process equipment. The EPA is retaining the requirement that appendix K does not on its own apply to anyone but must be referenced by a subpart before it would apply.

2. Operator Training

The EPA proposed a multi-layered training requirement for OGI camera operators because operator training is critical in developing the ability to see leaks with an OGI camera. The proposed training consisted of both an initial and annual classroom training on the fundamental concepts of OGI, basic operation of the camera, best practices for finding leaks, and the site's monitoring plan. appendix K also contained initial field training consisting of 100 site surveys with a senior OGI camera operator, where initially the trainee observes the senior OGI camera operator and then eventually is observed by the senior OGI camera operator, and a final site survey test with zero missed persistent leaks. Additionally, the EPA proposed quarterly performance audits for OGI camera operators either by comparative monitoring or a review of video footage by a senior OGI camera operator, where the auditee must have zero missed persistent leaks and a technique that aligns with the site's monitoring plan. Auditees not meeting these criteria must be retrained. The EPA also proposed that operators would be required to repeat initial training after 12 months of inactivity.

The EPA received numerous comments on all aspects of the proposed training requirements. Commenters stated that online training should be allowed for classroom training, and they recommended that periodic classroom training should be extended to every 2 or 3 years.³⁰⁹ Commenters also provided a broad range of recommendations on what the initial field training should

³⁰⁸ See Document ID Nos. EPA-HQ-OAR-2021-0317-0604, EPA-HQ-OAR-2021-0317-0748, EPA-HQ-OAR-2021-0317-0808, and EPA-HQ-OAR-2021-0317-0831.

³⁰⁹ See Document ID Nos. EPA-HQ-OAR-2021-0317-0561, EPA-HQ-OAR-2021-0317-0793, EPA-HQ-OAR-2021-0317-0808, EPA-HQ-OAR-2021-0317-0814, EPA-HQ-OAR-2021-0317-0831, EPA-HQ-OAR-2021-0317-0954, and EPA-HQ-OAR-2021-0317-1373.

look like.³¹⁰ The recommendations for initial training hours ranged from around 5 to 80 hours. Additionally, some commenters said the determination of suitability for independent monitoring should be based on observations and comparative monitoring, not on a set number of hours of training.³¹¹ Some commenters suggested reducing the final survey test to 1 hour.³¹² Commenters also suggested that requiring zero missed leaks during the final survey test was too stringent.³¹³ Some commenters thought the OGI camera operator audits were unnecessary, while others thought they were too frequent or too long. There was a range of recommendations on what the audit frequency should be, including annual or a stepped up and down frequency based on performance.³¹⁴ Additionally, commenters stated that requiring zero missed leaks during the audit was too stringent and that instead of a failed audit triggering automatic retraining, there should be an opportunity to counsel the auditee and let them try again.³¹⁵ Commenters thought returning operators should only be required to take refresher level training, pass a performance audit, or pass the final survey test.³¹⁶ Commenters also thought there should be some grandfathering of current OGI camera operators.³¹⁷ Finally, commenters stated that there should be

different performance audit and retraining requirements for small businesses and the Alaska North Slope.³¹⁸

Based on these comments, the EPA is proposing specific revisions or clarifications related to the operator training requirements. In this action, the EPA is clarifying our intent to allow classroom training to be online or in-person and revising the classroom refresher training frequency to biennial (*i.e.*, every 2 years). For the initial field training, the EPA is proposing 30 survey hours with a senior OGI camera operator and changing the final field test from one site to two survey hours. The EPA is also proposing to allow up to 10 percent missed leaks on the final survey test if there are more than 10 leaks found by the senior OGI camera operator during the final field test and is providing clarification on what happens if a trainee doesn't pass the final field test. In this instance, the senior OGI camera operator would discuss the failure with the trainee and provide instruction on improving performance, then allow the trainee to repeat the test. While the EPA is retaining quarterly operator audits, we are proposing to reduce the audit from four hours to two hours and allow up to 10 percent missed leaks if there are more than 10 leaks found by the senior OGI camera operator during the audit. While an auditee would still need to retrain following a failed audit, the EPA is proposing to reduce the amount of retraining from 25 site surveys to 16 survey hours and adding a requirement that the senior OGI camera operator counsel the auditee on the reasons for the failure and how to improve surveying techniques. However, if an auditee fails two consecutive audits, the auditee will have to complete the initial training again. The EPA is also proposing to reduce the amount of training required for OGI operators who have been inoperative for an extended period from the initial training requirements to the retraining requirements.

Finally, the EPA is proposing to allow previous OGI experience to substitute for some of the initial training requirements within appendix K in order to recognize the experience of current OGI camera operators. Specifically, OGI camera operators with previous classroom training (either at a physical location or online) that covers the majority of the elements required by the initial classroom training required in

appendix K prior to the finalization of appendix K will not need to complete the initial classroom training, but if the date of training is more than 2 years before the date that the appendix is finalized, the OGI camera operator will need to complete the biennial classroom training in lieu of the initial classroom training. Also, OGI camera operators who have 40 hours of experience over the 12 calendar months prior to the date that appendix K is finalized may substitute the retraining requirements, including the final monitoring survey test, for the initial field training requirements.

3. Senior OGI Camera Operator

The EPA proposed that a senior OGI camera operator is a camera operator who has conducted a minimum of 500 site surveys over their career, including at least 20 site surveys in the past year, and who has taken or developed the initial classroom training. Commenters were concerned that there may be a lack of available senior OGI camera operators, especially in the period right after finalization of appendix K.³¹⁹ Commenters also stated that the definition is too restrictive, and some were concerned there is no certification program.³²⁰ Some commenters also recommended that senior OGI operators should be removed from the auditing process since they are auditing and training others.³²¹

The EPA is proposing to change the definition of senior OGI camera operator to someone with 1400 survey hours over their career, including 40 hours in the past year. The 1400 survey hours is consistent with the level that experienced operators had during the studies on operator experience performed at the Methane Emissions Technology Evaluation Center (METEC) test site.³²² The study clearly showed a delineation of the detection capabilities of high experienced operators, with the high experienced operators detecting about 67 percent more leaks than other operators. The experience of the group of operators considered to be high experienced operators began at around 700 sites surveyed. The background

³¹⁰ See Document ID Nos. EPA-HQ-OAR-2021-0317-0463, EPA-HQ-OAR-2021-0317-0561, EPA-HQ-OAR-2021-0317-0608, EPA-HQ-OAR-2021-0317-0718, EPA-HQ-OAR-2021-0317-0749, EPA-HQ-OAR-2021-0317-0793, EPA-HQ-OAR-2021-0317-0808, EPA-HQ-OAR-2021-0317-0816, EPA-HQ-OAR-2021-0317-0831, and EPA-HQ-OAR-2021-0317-0934.

³¹¹ See Document ID Nos. EPA-HQ-OAR-2021-0317-0608 and EPA-HQ-OAR-2021-0317-0718.

³¹² See Document ID Nos. EPA-HQ-OAR-2021-0317-0808 and EPA-HQ-OAR-2021-0317-0831.

³¹³ See Document ID Nos. EPA-HQ-OAR-2021-0317-0599, EPA-HQ-OAR-2021-0317-0750, EPA-HQ-OAR-2021-0317-0782, EPA-HQ-OAR-2021-0317-0793, EPA-HQ-OAR-2021-0317-0808, EPA-HQ-OAR-2021-0317-0817, and EPA-HQ-OAR-2021-0317-0831.

³¹⁴ See Document ID Nos. EPA-HQ-OAR-2021-0317-0463, EPA-HQ-OAR-2021-0317-0561, EPA-HQ-OAR-2021-0317-0599, EPA-HQ-OAR-2021-0317-0608, EPA-HQ-OAR-2021-0317-0718, EPA-HQ-OAR-2021-0317-0749, EPA-HQ-OAR-2021-0317-0782, EPA-HQ-OAR-2021-0317-0808, EPA-HQ-OAR-2021-0317-0831, and EPA-HQ-OAR-2021-0317-0916.

³¹⁵ See Document ID Nos. EPA-HQ-OAR-2021-0317-0561, EPA-HQ-OAR-2021-0317-0599, EPA-HQ-OAR-2021-0317-0749, EPA-HQ-OAR-2021-0317-0808, and EPA-HQ-OAR-2021-0317-0831.

³¹⁶ See Document ID Nos. EPA-HQ-OAR-2021-0317-0463, EPA-HQ-OAR-2021-0317-0608, EPA-HQ-OAR-2021-0317-0718, EPA-HQ-OAR-2021-0317-0808, EPA-HQ-OAR-2021-0317-0816, and EPA-HQ-OAR-2021-0317-0831.

³¹⁷ See Document ID Nos. EPA-HQ-OAR-2021-0317-0808 and EPA-HQ-OAR-2021-0317-0831.

³¹⁸ See Document ID Nos. EPA-HQ-OAR-2021-0317-0814, EPA-HQ-OAR-2021-0317-0916, and EPA-HQ-OAR-2021-0317-1373.

³¹⁹ See Document ID Nos. EPA-HQ-OAR-2021-0317-0599, EPA-HQ-OAR-2021-0317-0750, EPA-HQ-OAR-2021-0317-0782, and EPA-HQ-OAR-2021-0317-0831.

³²⁰ See Document ID Nos. EPA-HQ-OAR-2021-0317-0599, EPA-HQ-OAR-2021-0317-0561, EPA-HQ-OAR-2021-0317-0608, EPA-HQ-OAR-2021-0317-0718, EPA-HQ-OAR-2021-0317-0750, EPA-HQ-OAR-2021-0317-0802, and EPA-HQ-OAR-2021-0317-0808.

³²¹ See Document ID Nos. EPA-HQ-OAR-2021-0317-0749, and EPA-HQ-OAR-2021-0317-0808.

³²² See Document ID No. EPA-HQ-OAR-2021-0317-0076.

document for the METEC study estimated experience at about four sites per day, which equates to about two hours per site. Therefore, based on the data used in the study, 700 sites should equate to about 1400 hours on average. Additionally, the EPA is clarifying that the hours spent by the senior OGI camera operator performing comparative monitoring, either as part of initial training, retraining, or auditing other OGI camera operators, can be included when determining the senior OGI camera operator's experience both over their career and the past 12 months.

4. Dwell Time

The EPA proposed that during a survey, OGI camera operators should view equipment from multiple angles. For each angle, the dwell time, the active time the operator is looking for potential leaks when the scene is in focus and steady, would need to be a minimum of 5 seconds per component in the field of view. Some commenters stated that there is no need to specify a dwell time, while other commenters said that the dwell time should be shorter.³²³ Still other commenters stated that the dwell time requirement should be based on the scene and not on a per component basis.³²⁴

The EPA is proposing to change the dwell time per angle to two seconds per component in the field of view. This aligns closely with the estimated time to complete a monitoring survey in the analysis performed for onshore natural gas processing plants for the proposed NSPS OOOOb.³²⁵ The EPA based that analysis on data provided by OGI camera operators. The EPA believes that two seconds per component would provide enough time to determine whether a leak is present, and it is expected that a trained OGI camera operator would be aware of situations that necessitate dwelling longer than the minimum required time.

5. Other Changes

The EPA proposed that OGI camera operators must take 5-minute rest breaks after 20 minutes of continuous surveying. This proposed requirement is

the same as the requirement for opacity observations in EPA Method 9 of 40 CFR part 60 appendix A–4. Commenters were divided over this requirement. Some commenters agreed with the principal of rest breaks while requesting additional flexibility or longer surveying times between breaks. Others felt it was unnecessary to mandate rest breaks.³²⁶

Rest breaks are an appropriate requirement for OGI camera operators because physical, mental, and eye fatigue are concerns with continuous field operation of OGI cameras. The EPA is proposing to update the requirement for rest breaks to once every 30 minutes, as one commenter³²⁷ noted that this makes tracking breaks easier. The EPA does not believe that changing the continuous survey period from 20 minutes to 30 minutes will have a detrimental effect on an operator's ability to see leaks, and as such, is proposing to update the requirement to ease the burden on operators performing surveys. The EPA is not proposing a change in the length of the rest break. No comments were received on the specific length of the rest break. The EPA also notes that operators may perform tasks related to the survey, such as documentation, during rest breaks; the rest break is solely a break from actively imaging components.

The EPA proposed that OGI cameras must be capable of imaging methane emissions of 17 grams per hour (g/hr) and butane emissions of 18.5 g/hr at a viewing distance of 2 meters and a delta-T of 5 °C in an environment of calm wind conditions. Commenters stated that gases other than butane should be used for certification of cameras.³²⁸ Additionally, some commenters stated that the emission rates in the camera certification should be the same as in NSPS OOOOa.³²⁹ While the EPA does not agree that the camera certification should be the same as what is in NSPS OOOOa because we have learned more about the detection capabilities of OGI cameras since that time, we are proposing to change the butane requirement to a choice between

propane or butane and noting that referencing subparts may provide specifications for other gases. The EPA is also clarifying that the initial certification testing, as well as the operating window development testing, can be performed by the owner or operator, the camera manufacturer, or a third party.

The EPA proposed that the response factors used when determining whether an OGI camera would be able to image the components in gaseous emissions would need to come from peer reviewed publications. Commenters requested that the EPA develop guidance on how to develop response factors and stated that the response factors should be able to be developed by manufacturers without the requirement for peer reviewed publication.³³⁰ The EPA agrees with these comments, and as such, is proposing to remove the requirement for peer reviewed publications. Guidance for developing response factors is being provided as annex 1 to appendix K.

The EPA found that when a leak is found with OGI, the OGI camera operator must take a video clip of the leak. As requested by commenters, this requirement is being updated to allow a photograph of leaks as an option in lieu of video clips.³³¹ Additionally, as requested by a commenter, the EPA is proposing to allow the option for full videos of the surveys to be retained in lieu of video clips of leaks.³³²

The EPA is proposing to add a definition of monitoring survey, which means imaging equipment with an OGI camera at one site on one day. Changing site location or changing the day of imaging would constitute a new monitoring survey. This definition is needed to help clarify some of the requirements related to recordkeeping for monitoring surveys.

Finally, the EPA is also making a number of other clarifications and minor edits based on comments received during the November 2021 proposal.

C. Summary of Proposed Requirements

In this action, the EPA is proposing a protocol for the use of OGI as appendix K. As part of the development of appendix K, the EPA conducted an extensive literature review on the technology development as well as

³²³ See Document ID Nos. EPA–HQ–OAR–2021–0317–0570, EPA–HQ–OAR–2021–0317–0599, EPA–HQ–OAR–2021–0317–0463, EPA–HQ–OAR–2021–0317–0608, EPA–HQ–OAR–2021–0317–0718, EPA–HQ–OAR–2021–0317–0782, EPA–HQ–OAR–2021–0317–0793, EPA–HQ–OAR–2021–0317–0808, EPA–HQ–OAR–2021–0317–0814, EPA–HQ–OAR–2021–0317–0816, EPA–HQ–OAR–2021–0317–0808, EPA–HQ–OAR–2021–0317–0831, EPA–HQ–OAR–2021–0317–0916, and EPA–HQ–OAR–2021–0317–0954.

³²⁴ See Document ID Nos. EPA–HQ–OAR–2021–0317–0561, EPA–HQ–OAR–2021–0317–0816, and EPA–HQ–OAR–2021–0317–0954.

³²⁵ See Chapter 10 of the November 2021 TSD at Document ID No. EPA–HQ–OAR–2021–0317–0166.

³²⁶ See Document ID Nos. EPA–HQ–OAR–2021–0317–0561, EPA–HQ–OAR–2021–0317–0599, EPA–HQ–OAR–2021–0317–0608, EPA–HQ–OAR–2021–0317–0718, EPA–HQ–OAR–2021–0317–0749, EPA–HQ–OAR–2021–0317–0750, EPA–HQ–OAR–2021–0317–0782, EPA–HQ–OAR–2021–0317–0793, EPA–HQ–OAR–2021–0317–0808, EPA–HQ–OAR–2021–0317–0814, EPA–HQ–OAR–2021–0317–0816, EPA–HQ–OAR–2021–0317–0954, and EPA–HQ–OAR–2021–0317–1373.

³²⁷ See Document ID No. EPA–HQ–OAR–2021–0317–0561.

³²⁸ See Document ID Nos. EPA–HQ–OAR–2021–0317–0599 and EPA–HQ–OAR–2021–0317–0808.

³²⁹ See Document ID Nos. EPA–HQ–OAR–2021–0317–0782 and EPA–HQ–OAR–2021–0317–0808.

³³⁰ See Document ID Nos. EPA–HQ–OAR–2021–0317–0808 and EPA–HQ–OAR–2021–0317–0831.

³³¹ See Document ID Nos. EPA–HQ–OAR–2021–0317–0463, EPA–HQ–OAR–2021–0317–0599, EPA–HQ–OAR–2021–0317–0808, EPA–HQ–OAR–2021–0317–0814 and EPA–HQ–OAR–2021–0317–1373.

³³² See Document ID No. EPA–HQ–OAR–2021–0317–0816.

observations on current application of OGI technology. Approximately 150 references identify the technology, applications, and limitations of OGI. The EPA also commissioned multiple laboratory studies and OGI technology evaluations. Additionally, on November 9 and 10, 2020, the EPA held a virtual stakeholder workshop to gather input on development of a protocol for the use of OGI. The information obtained from these efforts was used to develop the TSD for appendix K, which provides technical analyses, experimental results, and other supplemental information used to evaluate and develop standardized procedures for the use of OGI technology in monitoring for fugitive emissions of VOCs, HAP, and methane from industrial environments.³³³

The EPA notes that while this protocol is being proposed for use at onshore natural gas processing plants in this action at the proposed 40 CFR 60.5400b and 40 CFR 60.5400c, the applicability of the protocol is broader. The protocol is applicable to facilities when specified in a referencing subpart to help determine the presence and location of leaks; it is not currently applicable for use in direct emission rate measurements from sources. The protocol may be applied, when referenced, to surveys of process equipment using OGI cameras where the majority of compounds (>75 percent by weight) in the emissions streams have a response factor of at least 0.25 when compared to the response factor of propane. The OGI camera must also be capable of detecting (or producing a detectable image of) methane emissions of 17 g/hr and either butane emissions of 5.0 g/hr or propane emissions of 18 g/hr at a viewing distance of 2 meters and a delta-T of 5 °C in an environment of calm wind conditions around 1 meter per second or less. Verification that the OGI camera meets these criteria may be performed by the owner or operator, the camera manufacturer, or a third party. The supplies necessary for conducting the verification are described in section 6.2 of the proposed appendix.

Field conditions, such as the viewing distance to the component to be monitored, wind speed, ambient air temperature, and the background temperature, have the potential to impact the ability of the OGI camera operator to detect a leak. Because it is important that the OGI camera has been tested under the full range of expected field conditions in which the OGI camera will be used, an operating

envelope must be established for field use of the OGI camera. Imaging must not be performed when the conditions are outside of the developed operating envelope. Operating envelopes are specific to each model of OGI camera and can be developed by the owner or operator, the camera manufacturer, or a third party. To develop the operating envelope, methane gas is released at a set mass rate and wind speed, viewing distance, and delta-T (the temperature differential of the background and the released gas) are all varied to determine the conditions under which a leak can be imaged. For purposes of developing the operating envelope, a leak is considered able to be imaged if three out of four observers can see the leak. Once the operating envelope is developed using methane, the testing is repeated with either butane or propane gas. The operating envelope for the OGI camera is the more restrictive operating envelope developed between the different test gases.

The operating envelope must be confirmed for all potential configurations that could impact the detection limit of the OGI camera. In response to the November 2021 proposal, several commenters suggested that the operating envelope determination requirements should be streamlined. For example, if a configuration is established and confirmed, another configuration that is inherently more sensitive should be allowed without additional testing. Commenters also requested a more defined and acceptable list of configurations be provided based on the technology's capabilities, not user preferences.³³⁴ The EPA does not currently have enough data or empirical evidence to provide a complete list of possible configurations for all the available commercial OGI cameras (taking into account future possible configurations) or a definitive ranking of which configurations are more stringent than other. The EPA is requesting comment on this topic and seeking any empirical data that could be used to create such a defined ranking of configurations. Additionally, one commenter suggested that instead of having different operating envelopes for different situations and having to decide which envelope to use, the OGI camera operator should conduct a daily camera demonstration each day prior to imaging to determine the maximum distance at which the OGI camera operator should

image for that day.³³⁵ The EPA believes that this type of determination would be more difficult and costly than creating an operating envelope, as it would require OGI camera operators to have necessary gas supplies on hand and take time to do this determination daily, or potentially multiple times a day. Nevertheless, the EPA is requesting comment on this suggestion, as well as how such a demonstration could be used if conditions on the site change throughout the day, at what point would the changed conditions necessitate repeating the demonstration, and how changes in the background in different areas of the site (such as to affect the delta-T) would be factored into such a demonstration.

The EPA is proposing that each site would have a monitoring plan that describes the procedures for conducting a monitoring survey. One monitoring plan can be used for multiple sites, as long as the plan contains the relevant information for each site. The monitoring plan must contain procedures for a daily verification check, ensuring that the monitoring survey is performed only when conditions in the field are within the operating envelope, monitoring all the components regulated by the referencing subpart within the unit or area, viewing the components with the camera, operator rest breaks, documenting surveys, and quality assurance.

Delta-T is a crucial variable in determining whether it is possible to see a leak. Without an adequate delta-T, it will be difficult, or even impossible to see a leak, no matter how big the leak is. The EPA is proposing that the monitoring plan must describe how the operator will ensure an adequate delta-T is present in order to view potential gaseous emissions, *e.g.*, using a delta-T check function built into the features of the OGI camera or using a background temperature reading in the OGI camera field of view. In response to the November 2021 proposal, a commenter stated guidance should be added for operators who are using a background temperature reading in the OGI camera field of view.³³⁶ The EPA is requesting comment on ways that an OGI camera operator can ensure an adequate delta-T exists during monitoring surveys for cameras that do not have a built-in delta-T check function.

The EPA is proposing that a component must be imaged from at least

³³³ See Document ID No. EPA-HQ-OAR-2021-0317-0079.

³³⁴ See Document ID Nos. EPA-HQ-OAR-2021-0317-0604 and EPA-HQ-OAR-2021-0317-0954.

³³⁵ See Document ID No. EPA-HQ-OAR-2021-0317-0561.

³³⁶ See Document ID No. EPA-HQ-OAR-2021-0317-0719.

two different angles, and the OGI camera operator must dwell on each angle for a minimum of 2 seconds per component in the field of view, where dwell time is defined as the time the scene is steady and in focus and the operator is actively viewing the scene. The operator may reduce the dwell time for complex scenes based on the monitoring area and number of components in the subsection as prescribed in Table 14–1 of the appendix; use of this table is only required when an operator wants to reduce the dwell time from the minimum 2 second per component dwell time. In response to the November 2021 proposal, commenters suggested that dwell time should be based on the scene, not on a per component basis. Additionally, commenters suggested further defining the scene as “simple” or “complex” with a greater dwell time for “complex” scenes.³³⁷ The EPA is concerned with creating blanket dwell times for scenes, as scenes can vary in complexity within these categories, and an operator would need to look at scenes with more components longer than a scene with fewer components. Additionally, the EPA does not believe it is possible to describe every possible scene in order to create bins for “simple” and “complex” scenes that would be inclusive of all scenes an OGI camera operator might encounter in the field. However, the EPA is soliciting comment on how dwell time could be based on the scene while still accounting for the differences in the complexity of scenes or ways to create bins for “simple” and “complex” scenes. The EPA is also soliciting comment on ways to similarly achieve the goal of ensuring that OGI camera operators survey a scene for an adequate amount of time to ensure there are no leaks from any components in the field of view without specifying a dwell time.

Physical, mental, and eye fatigue are concerns with continuous field operation of OGI cameras. The EPA is proposing that OGI camera operators must take a rest break after surveying continuously for a period of 30 minutes. In response to the November 2021 proposal, commenters suggested that this was an unnecessary requirement. The EPA is aware that continuously surveying for long periods can lead to decreased detection of leaks. However, the EPA has heard anecdotally that this may have more to do with the number of hours the OGI camera operator has

surveyed during the day, such that it is more appropriate to limit the hours of surveying per day than it is to mandate rest breaks at a set frequency. The EPA is seeking any empirical data on the topic of the necessity of rest breaks when conducting OGI surveys or the link between operator performance and length of survey period.

The EPA is proposing that the facility or company performing the OGI surveys must have a training plan which ensures and monitors the proficiency of the OGI camera operators. If the facility does not perform its own OGI monitoring, the facility must ensure that the training plan for the company performing the OGI surveys adheres to this requirement. The proposed appendix K prescribes a multi-faceted approach to training. Training includes classroom instruction (either online or at a physical location) 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. Prior to conducting monitoring surveys, camera operators must demonstrate proficiency with the OGI camera. The initial field training includes a minimum of 30 survey hours with OGI where trainees first observe the techniques and methods of a senior OGI camera operator and then eventually perform monitoring surveys independently with a senior OGI camera operator present to provide oversight. The trainee must then pass a final monitoring survey test of at least two hours. If there are 10 or more leaks identified by the senior OGI operator, the trainee must achieve less than 10 percent missed persistent leaks relative to the senior OGI camera operator to be considered authorized for independent survey execution. If there are less than 10 leaks identified by the senior OGI operator, the trainee must achieve zero missed persistent leaks relative to the senior OGI camera operator to be considered authorized for independent survey execution. If the trainee doesn’t pass the monitoring survey test, the senior OGI camera operator must discuss the reasons for the failure with the trainee and provide instruction/correction on improving the trainee’s performance, following which the trainee may repeat the final test.

The EPA is proposing that performance audits for all OGI camera operators must occur on a quarterly basis and can be conducted either by comparative monitoring or video review by a senior OGI camera operator. If the senior OGI camera operator finds that the survey techniques during the video

review do not match those described in the monitoring plan, then the camera operator being audited will need to be retrained. Additionally, if there are 10 or more leaks identified by the senior OGI operator, the camera operator being audited must achieve less than 10 percent missed persistent leaks relative to the senior OGI camera operator. If there are less than 10 leaks identified by the senior OGI operator, the camera operator being audited must achieve zero missed persistent leaks relative to the senior OGI camera operator. Retraining consists of a discussion of the reasons for the failure with the OGI operator being audited and techniques to improve performance; a minimum of 16 survey training hours; and a final monitoring survey test. If an OGI operator requires retraining in two consecutive quarterly audits, the OGI operator must repeat the initial training requirements. In response to the November 2021 proposal, commenters stated that there should be no performance audit requirements for senior OGI camera operators because senior OGI camera operators are responsible for training and auditing other OGI camera operators. The EPA believes that it is important to verify the performance of all OGI camera operators, even the most experienced operators, on an ongoing basis. Nevertheless, the EPA is requesting comment on whether there should be a reduced performance audit frequency for certain OGI camera operators, and if so, who should qualify for a reduced frequency, what the reduced frequency should be, and the basis for the reduced frequency.

Previous experience with OGI camera operation can be substituted for some of the initial training requirements. OGI camera operators with previous classroom training (either at a physical location or online) that covers the majority of the elements required by the initial classroom training required in appendix K prior to the finalization of appendix K do not need to complete the initial classroom training, but if the date of certification is more than 2 years before the publication date of the final rule, the biennial classroom training must be completed in lieu of the initial classroom training. OGI camera operators who have 40 hours of experience over the 12 calendar months prior to the date of publication of the final rule may substitute the retraining requirements, including the final monitoring survey test, for the initial field training requirements.

Recordkeeping is an important compliance assurance measure. The proposed appendix K requires records

³³⁷ See Document ID Nos. EPA–HQ–OAR–2021–0317–0561, EPA–HQ–OAR–2021–0317–0604, EPA–HQ–OAR–2021–0317–0816, and EPA–HQ–OAR–2021–0317–0954.

to be retained in hard copy or electronic form. Records include the site monitoring plan, operating envelope limitations, data supporting the initial OGI camera performance verification and development of the operating envelope, the training plan for OGI camera operators, OGI camera operator training and auditing records, records necessary to verify senior OGI camera operator status, monitoring survey records, quality assurance verification videos for each operator, and maintenance and calibration records. Some of the records required by the proposed appendix K are not required to be kept onsite as long as the owner or operator can easily access these records and can make the records available for review if requested by the Administrator.

VII. Impacts of This Proposed Rule

A. What are the air impacts?

The EPA projected that, from 2023 to 2035, relative to the baseline, the proposed NSPS OOOOb and EG OOOOc will reduce about 36 million short tons of methane emissions (810 million tons CO₂ Eq.), 9.7 million short tons of VOC emissions, and 390 thousand short tons of HAP emission from facilities that are potentially affected by this proposal. The EPA projected regulatory impacts beginning in 2023 as that year represents the first full year of implementation of the proposed NSPS OOOOb. The EPA assumes that emissions impacts of the proposed EG OOOOc will begin in 2026. The EPA projected impacts through 2035 to illustrate the accumulating effects of this rule over a longer period. The EPA did not estimate impacts after 2035 for reasons including limited information, as explained in the RIA, though the EPA is soliciting comment on whether information exists to better characterize the likely effects beyond 2035.

As noted in section I of this preamble, the updated analysis not only incorporates the new provisions put forth in the supplemental proposal (in addition to the elements of the November 2021 proposal that are unchanged), but also includes key updates to assumptions and methodologies that impact both the baseline and policy scenarios. Accordingly, these estimates of air impacts are not directly comparable to corresponding estimates presented in the November 2021 proposal.

B. What are the energy impacts?

The energy impacts described in this section are those energy requirements associated with the operation of

emission control devices. Potential impacts on the national energy economy from the rule are discussed in the economic impacts section in VIII.D of this preamble. There will likely be minimal change in emissions control energy requirements resulting from this rule. Additionally, this proposed action continues to encourage the use of emission controls that recover hydrocarbon products that can be used on-site as fuel or reprocessed within the production process for sale.

C. What are the compliance costs?

The equivalent annualized value, or EAV, of the regulatory compliance cost associated with the proposed NSPS OOOOb and EG OOOOc over the 2023 to 2035 period was estimated to be \$1.4 billion per year using a 3-percent discount rate and \$1.4 billion using a 7-percent discount rate. The corresponding estimates of the present value (PV) of compliance costs were \$14 billion (in 2019 dollars) using a 3-percent discount rate and \$12 billion using a 7-percent discount rate. These estimates include the producer revenues associated with the projected increase in the recovery of saleable natural gas, using the 2022 Annual Energy Outlook (AEO) projection of natural gas prices to estimate the value of the change in the recovered gas at the wellhead projected to result from the proposed action. Estimates of the value of the recovered product have been included in previous regulatory analyses as offsetting compliance costs and are appropriate to include when assessing the societal cost of a regulation. If the recovery of saleable natural gas is not accounted for, the EAV of the regulatory compliance costs of the proposed rule over the 2023 to 2035 period were estimated to be \$1.8 billion per year using a 3-percent discount rate and \$1.8 billion per year using a 7-percent discount rate. The PV of these costs were estimated to be \$19 billion using a 3-percent discount rate and \$15 billion using a 7-percent discount rate.

D. What are the economic and employment impacts?

The EPA conducted an economic impact and distributional analysis for this proposal, as detailed in section 4 of the RIA for this supplemental proposal. To provide a partial measure of the economic consequences of the proposed NSPS OOOOb and EG OOOOc, the EPA developed a pair of single-market, static partial-equilibrium analyses of national crude oil and natural gas markets. We implemented the pair of single-market analyses instead of a coupled market or general equilibrium approach to provide

broad insights into potential national-level market impacts while providing maximum analytical transparency. We estimated the price and quantity impacts of the proposed NSPS OOOOb and EG OOOOc on crude oil and natural gas markets for a subset of years within the time horizon analyzed in the RIA. The models are parameterized using production and price data from the U.S. Energy Information Administration and supply and demand elasticity estimates from the economics literature.

The RIA projects that regulatory costs are at their highest in 2026, the first year the requirements of both the proposed NSPS OOOOb and EG OOOOc are assumed to be in effect and will represent the year with the largest market impacts based upon the partial equilibrium modeling. We estimated that the proposed rule could result in a maximum decrease in annual natural gas production of about 358 million Mcf in 2026 (or about 1.00 percent of natural gas production) with a maximum price increase of \$0.07 per Mcf (or about 2.35 percent). We estimated the maximum annual reduction in crude oil production would be about 21 million barrels (or about 0.52 percent of crude oil production) with a maximum price increase of about \$0.10 per barrel (or less than 0.16 percent).

Before 2026, the modeled market impacts are much smaller than the 2026 impacts as only the incremental requirements under the proposed NSPS OOOOb are assumed to be in effect. As regulatory costs are projected to decline after 2026, the modeled market impacts for years after 2026 are smaller than the peaks estimated for 2026. Please see section 4.1 of the RIA for more detail on the formulation and implementation of the model as well as a discussion of several important caveats and limitations associated with the approach.

As discussed in the RIA for this proposal, employment impacts of environmental regulations are generally composed of a mix of potential declines and gains in different areas of the economy over time. Regulatory employment impacts can vary across occupations, regions, and industries; by labor and product demand and supply elasticities; and in response to other labor market conditions. Isolating such impacts is a challenge, as they are difficult to disentangle from employment impacts caused by a wide variety of ongoing, concurrent economic changes.

The oil and natural gas industry directly employs approximately 140,000 people in oil and natural gas extraction, a figure which varies with market prices

and technological change and employs a large number of workers in related sectors that provide materials and services.³³⁸ As indicated above, the proposed NSPS OOOOb and EG OOOOc are projected to cause small changes in oil and natural gas production and prices. As a result, demand for labor employed in oil and natural gas-related activities and associated industries might experience adjustments as there may be increases in compliance-related labor requirements as well as changes in employment due to quantity effects in directly regulated sectors and sectors that consume oil and natural gas products.

E. What are the benefits of the proposed standards?

To satisfy the requirement of E.O. 12866 and to inform the public, the EPA estimated the climate and health benefits due to the emissions reductions projected under the proposed NSPS OOOOb and EG OOOOc. The EPA expects climate and health benefits due to the emissions reductions projected under the proposed NSPS OOOOb and EG OOOOc. The EPA estimated the climate benefits of CH₄ emission reductions expected from this proposed rule using the SC-CH₄ estimates presented in the “Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under E.O. 13990 (IWG 2021)” published in February 2021 by the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG). The SC-CH₄ is the monetary value of the net harm to society associated with a marginal increase in emissions in a given year, or the benefit of avoiding that increase. In principle, SC-CH₄ includes the value of all climate change impacts, including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC-CH₄ therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CH₄ emissions.

The interim estimates of the social cost of methane and other greenhouse gases (collectively referred to as the social cost of greenhouse gases (SC-GHG)) presented in the February 2021

Technical Support Document (TSD) (IWG 2021) were developed over many years, using a transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. As a member of the IWG involved in the development of the February 2021 TSD, the EPA agrees that the interim SC-GHG estimates continue to represent at this time the most appropriate estimate of the SC-GHG until revised estimates have been developed reflecting the latest, peer-reviewed science. However, while the IWG’s SC-GHG work under E.O. 13990 continues, the RIA accompanying this proposal the EPA presents a sensitivity analysis of the monetized climate benefits using a set of SC-CH₄ estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017).

We invite the public to comment on both the sensitivity analysis of the monetized climate benefits and the accompanying external review draft technical report that the EPA has prepared that explains the methodology underlying the newer set of SC-CH₄ estimates. This report is also included as supporting material for the RIA in the docket.³³⁹ However, we emphasize that the monetized benefits analysis is entirely distinct from the statutory BSER determinations proposed herein and is presented solely for the purposes of complying with E.O. 12866. As discussed in more detail in the November 2021 proposal and earlier in this notice, the EPA weighed the relevant statutory factors to determine the appropriate proposed standards and did not rely on the monetized benefits analysis for purposes of determining the standards. E.O. 12866 separately requires the EPA to perform a benefit-cost analysis, including monetizing costs and benefits where practicable, and the EPA has conducted such an analysis. The monetized climate benefits calculated using the SC-CH₄ are included in the benefit-cost analysis, and thus, as is generally the case with any analytical methods, data, or results associated with RIAs, the EPA welcomes the opportunity to continually improve its understanding through public input on these estimates.

The EPA estimated the PV of the climate benefits over the 2023 to 2035 period to be \$48 billion at a 3-percent discount rate. The EAV of these benefits is estimated to be \$4.5 billion per year

at a 3-percent discount rate. These values represent only a partial accounting of climate impacts from methane emissions and do not account for health effects of ozone exposure from the increase in methane emissions.

Under the proposed NSPS OOOOb and EG OOOOc, the EPA expects that VOC emission reductions will improve air quality and are likely to improve health and welfare associated with exposure to ozone, PM_{2.5}, and HAP. Calculating ozone impacts from VOC emissions changes requires information about the spatial patterns in those emissions changes. In addition, the ozone health effects from the proposed rule will depend on the relative proximity of expected VOC and ozone changes to population. In this analysis, we have not characterized VOC emissions changes at a finer spatial resolution than the national total. In light of these uncertainties, we present an illustrative screening analysis in Appendix C of the RIA based on modeled oil and natural gas VOC contributions to ozone concentrations as they occurred in 2017 and do not include the results of this analysis in the estimate of benefits and net benefits projected from this proposal.

VIII. Statutory and Executive Order Reviews

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

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This proposed action is an economically significant regulatory action that was submitted to the OMB for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, “Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review”, is available in the docket and describes in detail the EPA’s assumptions and characterizes the various sources of uncertainties affecting the estimates.

B. Paperwork Reduction Act (PRA)

The information collection activities in the proposed amendments for 40 CFR part 60, subparts OOOOb and OOOOc,

³³⁸ Employment figure drawn from the Bureau of Labor Statistics Current Employment Statistics for NAICS code 211.

³³⁹ For more information about the development of these estimates, see www.epa.gov/environmental-economics/scghg.

have been submitted for approval to the OMB under the PRA. The ICR document that the EPA prepared has been assigned OMB Control No. 2060-0721 and EPA ICR number 2523.05. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. As noted in section IV.N of this supplemental preamble, draft versions of the proposed templates for the semiannual and annual reports for these subparts are included in the docket for this action,³⁴⁰ and the EPA specifically requests comment on the content, layout, and overall design of the templates.

40 CFR Part 60, Subpart OOOOb

This ICR reflects the EPA's proposed NSPS OOOOb for a wide range of emissions sources in the Crude Oil and Natural Gas source category. The information collected will be used by the EPA and delegated state and local agencies to determine the compliance status of affected facilities subject to the rule.

Respondents/affected entities: Oil and natural gas operators and owners; approved third-party notifiers.

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 1,849.

Frequency of response: Varies depending on affected facility.³⁴¹

Total estimated burden: 883,625 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: \$58,535,262(\$2019) (per year), which includes \$12,182,846 in capital costs.

40 CFR Part 60, subpart OOOOc

This rule does not directly impose specific requirements on oil and natural gas facilities located in states or areas of Indian country. The rule also does not impose specific requirements on tribal governments that have affected facilities located in their area of Indian country. This rule does impose specific requirements on state governments with affected oil and natural gas facilities. The information collection requirements are based on the recordkeeping and reporting burden associated with developing, implementing, and enforcing a plan to limit GHG emissions from existing sources in the oil and natural gas sector. These recordkeeping

and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

The annual burden for this collection of information for the states (averaged over the first 3 years following promulgation) is estimated to range from 55,467 to 69,333 hours at a total annual labor cost of between \$7 to \$8.8 million. The annual burden for the Federal government associated with the state collection of information (averaged over the first 3 years following promulgation) is estimated to be 22,520 hours at a total annual labor cost of \$1,399,930. The annual burden for industry (averaged over the first 3 years following promulgation) is estimated to be 2.2 million hours at a total annual labor cost of \$166 million. We realize, however, that some facilities may not incur these costs within the first 3 years and may incur them during the fourth or fifth year instead. Therefore, this ICR presents a conservatively high burden estimate for the initial 3 years following promulgation of the proposed emission guidelines. Burden is defined at 5 CFR 1320.3(b).

Respondents/affected entities: States with one or more designated facilities covered under subpart OOOOc.

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 50.

Frequency of response: Once.

Total estimated burden: 69,333 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: \$8,822,020 (per year), which includes \$36,750 in capital costs.

An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. The EPA will respond to any ICR-related comments in the final rule.

Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to www.reginfo.gov/public/do/PRAMain. Find this particular

information collection by selecting "Currently under 30-day Review—Open for Public Comments" or by using the search function. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than January 5, 2023.

C. Regulatory Flexibility Act (RFA)

Pursuant to section 603 of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) that examined the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact. The complete IRFA is available for review in the RIA (see Section 4.3) and the EPA is soliciting comment on the presentation of its analysis of the impacts on small entities, particularly if there is value in presenting more granular information beyond a focus on entities above and below the SBA size classifications.

As required by section 609(b) of the RFA, the EPA also convened a Small Business Advocacy Review (SBAR) Panel to obtain advice and recommendations from small entity representatives that potentially would be subject to the rule's requirements. The SBAR Panel evaluated the assembled materials and small-entity comments on issues related to elements of an IRFA. A copy of the full SBAR Panel Report is available in the rulemaking docket.

As required by section 604 of the RFA, the EPA will prepare a final regulatory flexibility analysis (FRFA) for this action as part of the final rule. The FRFA will address the issues raised by public comments on the IRFA.

D. Unfunded Mandates Reform Act (UMRA)

The NSPS contains a federal mandate under UMRA, 2 U.S.C. 1531–1538, that may result in expenditures of \$100 million or more for state, tribal, and local governments, in the aggregate, or the private sector in any one year. Accordingly, the EPA has prepared under section 202 of the UMRA a written statement of the benefit-cost analysis, which can be found in Section VII of this preamble, and in Chapter 1 of the RIA.

Consistent with section 205, the EPA has identified and considered a reasonable number of regulatory alternatives. These alternatives are described in Section IV of this preamble.

The EG is proposed under CAA section 111(d) and does not impose any direct compliance requirements on designated facilities, apart from the

³⁴⁰ See Part 60_Subpart OOOOb_60.5420b(b)_Annual_Report.xlsx and Part 60_Subpart OOOOb_60.5422b(b)_Semiannual_Report.xlsx, available in the docket for this action.

³⁴¹ The specific frequency for each information collection activity within this request is shown in Tables 1a through 1d of the Supporting Statement in the public docket.

requirement for states to develop state plans. As explained in section XIV.G. of the November 2021 proposal³⁴² and section V of this supplemental proposal, the EG also does not impose specific requirements on tribal governments that have designated facilities located in their area of Indian country. The burden for states to develop state plans following promulgation of the rule is estimated to be below \$100 million in any one year. Thus, the EG is not subject to the requirements of section 203 or section 205 of the UMRA.

The NSPS and EG are also not subject to the requirements of section 203 of UMRA because, as described in 2 U.S.C. 1531–38, they contain no regulatory requirements that might significantly or uniquely affect small governments. Specifically, for the EG the state governments to which rule requirements apply are not considered small governments. In light of the interest among governmental entities, the EPA conducted pre-proposal outreach with national organizations representing states and tribal governmental entities while formulating the proposed rule as discussed in section VII of the November 2021 proposal.³⁴³ The EPA considered the stakeholders' experiences and lessons learned to help inform how to better structure this proposal and consider ongoing challenges that will require continued collaboration with stakeholders. With this proposal, the EPA seeks further input from states and tribes. For public input to be considered during the formal rulemaking, please submit comments on this proposed action to the formal regulatory docket at EPA Docket ID No. EPA–HQ–OAR–2021–0317 so that the EPA may consider those comments during the development of the final rule.

E. Executive Order 13132: Federalism

Under Executive Order 13132, the EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal Government provides the funds necessary to pay the direct compliance costs incurred by state and local governments, or the EPA consults with state and local officials early in the process of developing the proposed action.

The proposed NSPS OOOOb and proposed EG OOOOc do not have federalism implications. These actions will not have substantial direct effects on the states as defined in the Executive

Order, on the relationship between the Federal Government and the States, or on the distribution of power and responsibilities among the various levels of government.

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

This action has tribal implications. However, it will neither impose substantial direct compliance costs on Federally recognized Tribal governments, nor preempt Tribal law, and does not have substantial direct effects on the relationship between the Federal Government and Indian Tribes or on the distribution of power and responsibilities between the Federal Government and Indian Tribes, as specified in E.O. 13175. See 65 FR 67249 (November 9, 2000). As stated in the November 2021 proposal, the EPA found that 112 unique tribal lands are located within 50 miles of an affected oil and natural gas source, and 32 tribes have one or more oil or natural gas sources on their lands.³⁴⁴ The majority of the designated facilities impacted by proposed NSPS and EG on Tribal lands are owned by private entities, and tribes will not be directly impacted by the compliance costs associated with this rulemaking. There would only be tribal implications associated with this rulemaking in the case where a unit is owned by a Tribal government or in the case of the NSPS, a Tribal government is given delegated authority to enforce the rulemaking. Tribes are not required to develop plans to implement the EG under CAA section 111(d) for designated existing sources. The EPA notes that this supplemental proposal does not directly impose specific requirements on designated facilities, including those located in Indian country. Before developing any standards for sources on Tribal land, the EPA would consult with leaders from affected tribes.

After the November 2021 proposal, the EPA held consultation with the Mandan, Hidatsa, and Arikara Nation (January 24, 2022), the Northern Arapaho Tribe (January 24, 2022), and the Eastern Shoshone Tribe (January 25, 2022).³⁴⁵ Consistent with previous actions affecting the Crude Oil and Natural Gas source category, the EPA understands there is continued significant tribal interest because of the growth of the oil and natural gas production in Indian country. In accordance with the EPA Policy on

Consultation and Coordination with Indian Tribes, the EPA will continue to engage in consultation with tribal officials during the development of this supplemental proposal.

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

This action is subject to E.O. 13045 (62 FR 19885; April 23, 1997) because it is an economically significant regulatory action as defined by E.O. 12866, and the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. Accordingly, the Agency has evaluated the environmental health and welfare effects of climate change on children. GHGs, including methane, contribute to climate change and are emitted in significant quantities by the oil and gas industry. The EPA believes that the GHG emission reductions resulting from implementation of these proposed standards and guidelines, if finalized will further improve children's health. The assessment literature cited in the EPA's 2009 Endangerment Findings concluded that certain populations and life stages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects (74 FR 66524). The assessment literature since 2009 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience (e.g., the 2016 Climate and Health Assessment).³⁴⁶ These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households. More

³⁴² See 86 FR 63256 (November 15, 2021).

³⁴³ See 86 FR 63145 (November 15, 2021).

³⁴⁴ 86 FR 63143 (November 15, 2021).

³⁴⁵ See memorandums located at Docket ID No. EPA–HQ–OAR–2021–0317.

³⁴⁶ USGCRP, 2016: The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment. Crimmins, A. J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C. Sarofim, J. Trtanj, and L. Ziska, Eds. U.S. Global Change Research Program, Washington, DC, 312 pp. <http://dx.doi.org/10.7930/J0R49NQX>.

detailed information on the impacts of climate change to human health and welfare is provided in sections III and VI of the November 2021 proposal³⁴⁷ and section VII of this preamble.

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

This action, which is a significant regulatory action under Executive Order 12866, has a significant adverse effect on the supply, distribution or use of energy. The documentation for this decision is contained in the *Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* prepared for the November 2021 proposal and the *Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* for this action³⁴⁸

I. National Technology Transfer and Advancement Act (NTTAA)

This proposed action for NSPS OOOOb and EG OOOOc involves technical standards. Therefore, the EPA conducted searches for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). Searches were conducted for EPA Methods 1, 1A, 2, 2A, 2C, 2D, 3A, 3B, 3C, 4, 6, 10, 15, 16, 16A, 18, 21, 22, and 25A of 40 CFR part 60, appendix A. No applicable voluntary consensus standards were identified for EPA Methods 1A, 2A, 2D, 21, and 22 and none were brought to its attention in comments. All potential standards were reviewed to determine the practicality of the voluntary consensus standards (VCS) for this rule. Two VCS were identified as an acceptable alternative to EPA test methods for the purpose of this proposed rule. First, ANSI/ASME PTC 19–10–1981, Flue and Exhaust Gas Analyses (Part 10) (manual portions only and not the instrumental portion) was identified to be used in lieu of EPA

Methods 3B, 6, 6A, 6B, 15A and 16A. This standard includes manual and instrumental methods of analysis for carbon dioxide, carbon monoxide, hydrogen sulfide, nitrogen oxides, oxygen, and sulfur dioxide. Second, ASTM D6420–99 (2010), “Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry” is an acceptable alternative to EPA Method 18 with the following caveats, only use when the target compounds are all known and the target compounds are all listed in ASTM D6420 as measurable. ASTM D6420 should never be specified as a total VOC Method. (ASTM D6420–99 (2010) is not incorporated by reference in 40 CFR part 60.) The search identified 19 VCS that were potentially applicable for this proposed rule in lieu of EPA reference methods. However, these have been determined to not be practical due to lack of equivalency, documentation, validation of data and other important technical and policy considerations. For additional information, please see the September 10, 2021, memo titled, “Voluntary Consensus Standard Results for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review.”³⁴⁹ In this document, the EPA is proposing to include in a final rule regulatory text for 40 CFR part 60, subpart OOOOb and OOOOc that includes incorporation by reference. In accordance with requirements of 1 CFR part 51, the EPA is proposing to incorporate the following ten standards by reference.

- ASTM D86–96, Distillation of Petroleum Products (Approved April 10, 1996) covers the distillation of natural gasolines, motor gasolines, aviation gasolines, aviation turbine fuels, special boiling point spirits, naphthas, white spirit, kerosenes, gas oils, distillate fuel oils, and similar petroleum products, utilizing either manual or automated equipment.
- ASTM D1945–03 (Reapproved 2010), Standard Test Method for Analysis of Natural Gas by Gas Chromatography covers the determination of the chemical composition of natural gases and similar gaseous mixtures within a certain range of composition. This test method may be abbreviated for the analysis of lean natural gases containing negligible amounts of hexanes and higher hydrocarbons, or for the determination of one or more components.

- ASTM D3588–98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuel covers procedures for calculating heating value, relative density, and compressibility factor at base conditions for natural gas mixtures from compositional analysis. It applies to all common types of utility gaseous fuels.

- ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion covers the determination of the heating value of natural gases and similar gaseous mixtures within a certain range of composition.

- ASTM D6522–00 (Reapproved December 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers covers the determination of nitrogen oxides, carbon monoxide, and oxygen concentrations in controlled and uncontrolled emissions from natural gas-fired reciprocating engines, combustion turbines, boilers, and process heaters.

- ASTM E168–92, General Techniques of Infrared Quantitative Analysis covers the techniques most often used in infrared quantitative analysis. Practices associated with the collection and analysis of data on a computer are included as well as practices that do not use a computer.

- ASTM E169–93, General Techniques of Ultraviolet Quantitative Analysis (Approved May 15, 1993) provide general information on the techniques most often used in ultraviolet and visible quantitative analysis. The purpose is to render unnecessary the repetition of these descriptions of techniques in individual methods for quantitative analysis.

- ASTM E260–96, General Gas Chromatography Procedures (Approved April 10, 1996) is a general guide to the application of gas chromatography with packed columns for the separation and analysis of vaporizable or gaseous organic and inorganic mixtures and as a reference for the writing and reporting of gas chromatography methods.

- ASME/ANSI PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus] (Issued August 31, 1981) covers measuring the oxygen or carbon dioxide content of the exhaust gas.

- EPA–600/R–12/531, EPA Traceability Protocol for Assay and Certification of Gaseous Calibration

³⁴⁷ See 86 FR 63124 and 86 FR 63139 (November 15, 2021).

³⁴⁸ See Document ID No. EPA–HQ–OAR–2021–0317–0173.

³⁴⁹ See Document ID No. EPA–HQ–OAR–2021–0317–0072.

Standards (Issued May 2012) is mandatory for certifying the calibration gases being used for the calibration and audit of ambient air quality analyzers and continuous emission monitors that are required by numerous parts of the CFR.

The EPA determined that the ASTM and ASME/ANSI standards, notwithstanding the age of the standards, are reasonably available because they are available for purchase from the following addresses: ASTM International (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959; or ProQuest, 300 North Zeeb Road, Ann Arbor, MI 48106 and the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990. The EPA determined that the EPA standard is reasonably available because it is publicly available through the EPA's website: [https://](https://nepis.epa.gov/Adobe/PDF/P100EKJR.pdf)

nepis.epa.gov/Adobe/PDF/P100EKJR.pdf.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially applicable VCS and to explain why such standards should be used in this regulation.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

This action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations, and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629; February 16, 1994). The documentation for this assessment is contained in section 4 of the *Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing*

Sources: Oil and Natural Gas Sector Climate Review prepared for the November 2021 proposal and in section 4 of the *Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* prepared for this action.³⁵⁰

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference; Reporting and recordkeeping requirements.

Michael S. Regan,
Administrator.

[FR Doc. 2022–24675 Filed 12–5–22; 8:45 am]

BILLING CODE 6560–50–P

³⁵⁰ See Document ID No. EPA–HQ–OAR–2021–0317–0173.