ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2021–0317; FRL–8510–02–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: Proposed rule.

SUMMARY: This document comprises three distinct groups of actions under the Clean Air Act (CAA) which are collectively 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 to revise the new source performance standards (NSPS) for GHGs and volatile organic compounds (VOCs) for the Crude Oil and Natural Gas source category under the CAA to reflect the Agency's most recent review of the feasibility and cost of reducing emissions from these sources. Second, the EPA proposes emissions guidelines (EG) under the CAA, for states to follow in developing, submitting, and implementing state plans to establish performance standards to limit GHGs from existing sources (designated facilities) in the Crude Oil and Natural Gas source category. Third, the EPA is taking several related actions stemming from the joint resolution of Congress, adopted on June 30, 2021 under the Congressional Review Act (CRA), disapproving the EPA's final rule titled, ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review,'' Sept. 14, 2020 (''2020 Policy Rule''). This proposal responds to the President's January 20, 2021, Executive order (E.O.) titled ''Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis,'' which directed the EPA to consider taking the actions proposed here.

DATES:

Comments. Comments must be received on or before January 14, 2022. Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before December 15, 2021.

Public hearing: The EPA will hold a virtual public hearing on November 30, 2021 and December 1, 2021. 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. Out of an abundance of caution for members of the public and our staff, the EPA Docket Center and Reading Room are closed to the public, with limited exceptions, to reduce the risk of transmitting COVID–19. Our Docket Center staff will continue to provide remote customer service via email, phone, and webform. We encourage the public to submit comments via *https://www.regulations.gov/* or email, as there may be a delay in processing mail and faxes. Hand deliveries and couriers may be received by scheduled appointment only. 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; facsimile number: (919) 541–3470; email address: *hambrick.amy@epa.gov.*

SUPPLEMENTARY INFORMATION:

Participation in virtual public hearing. Please note that the EPA is deviating from its typical approach for public hearings, because the President has declared a national emergency. Due to the current Centers for Disease Control and Prevention (CDC) recommendations, as well as state and local orders for social distancing to limit the spread of COVID–19, the EPA cannot hold in-person public meetings at this time.

The public hearing will be held via virtual platform on November 30, 2021, and December 1, 2021, and will convene at 11:00 a.m. Eastern Time (ET) and conclude at 9:00 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 December 2, 2021. 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 upon 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 November 24, 2021. 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 5 minutes to provide oral testimony. The EPA encourages commenters to provide the EPA with a copy of their oral testimony electronically (via email) by emailing it to *marsh.karen@epa.gov* and *hambrick.amy@epa.gov.* The EPA also recommends 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 November 22, 2021. 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 information that you consider to be CBI or otherwise protected through *https://www.regulations.gov/* or email. This type of information should be submitted by mail 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.*

The EPA is temporarily suspending its Docket Center and Reading Room for public visitors, with limited exceptions, to reduce the risk of transmitting COVID–19. Our Docket Center staff will continue to provide remote customer service via email, phone, and webform. We encourage the public to submit comments via *https://www.regulations.gov/* as there may be a delay in processing mail and faxes. Hand deliveries or couriers will be received by scheduled appointment only. For further information and updates on EPA Docket Center services, please visit us online at *https://www.epa.gov/dockets.*

The EPA continues to carefully and continuously monitor information from the CDC, local area health departments, and our Federal partners so that we can respond rapidly as conditions change regarding COVID–19.

Submitting CBI. Do not submit information containing CBI to the EPA through *https://www.regulations.gov/* or email. 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, mark the outside of the digital storage media as CBI and then 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 *Instructions* above. 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. 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 CFR part 2. Send or deliver information identified as CBI only 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. Note that written comments containing CBI submitted by mail may be delayed and no hand deliveries will be accepted.

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:

ACE Affordable Clean Energy rule
AEO Annual Energy Outlook
AMEL alternate means of emissions limitation
ANGA American Natural Gas Alliance
ANSI American National Standards Institute
APCD air pollution control devices
API American Petroleum Institute
ARPA–E Advanced Research Projects Agency-Energy
ASME American Society of Mechanical Engineers

ASTM American Society for Testing and Materials
AVO audio, visual, olfactory
BACT best achievable control technology
BOEM Bureau of Ocean Energy Management
BLM Bureau of Land Management
BMP best management practices
boe barrels of oil equivalents
BSER best system of emission reduction
BTEX benzene, toluene, ethylbenzene, and xylenes
CAA Clean Air Act
CBI Confidential Business Information
CDC Center for Disease Control
CDX EPA's Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
CH_4 methane
cm centimeter
CPI consumer price index
CPI–U consumer price index urban
CO carbon monoxide
COPD chronic obstructive pulmonary disease
CO_2 carbon dioxide
CO_2 Eq. carbon dioxide equivalent
COA condition of approval
COS carbonyl sulfide
CRA Congressional Review Act
CS_2 carbon disulfide
CVS closed vent systems
DC direct current
DOE Department of Energy
DOI Department of the Interior
DOT Department of Transportation
EAV equivalent annualized value
EDF Environmental Defense Fund
EG emission guidelines
ECOS Environmental Council of the States
EGU electricity generating units
EIA U.S. Energy Information Administration
EJ environmental justice
EO Executive Order
EPA Environmental Protection Agency
ERT Electronic Reporting Tool
FERC The U.S. Federal Energy Regulatory Commission
fpm feet per minute
GC gas chromatograph
GHGs greenhouse gases
GHGI Inventory of U.S. Greenhouse Gas Emissions and Sinks
GHGRP Greenhouse Gas Reporting Program
GRI Gas Research Institute
GWP global warning potential
HAP hazardous air pollutant(s)
HC hydrocarbons
HFC hydrofluorocarbons
H_2S hydrogen sulfide
ICR Information Collection Request
IOGCC Interstate Oil and Gas Compact Commission
IPCC Intergovernmental Panel on Climate Change
IR infrared
IRFA initial regulatory flexibility analysis
kt kilotons
kg kilograms
low-e low emission
LDAR leak detection and repair
Mcf thousand cubic feet
MMT million metric tons
MRR monitoring, recordkeeping, and reporting
MW megawatt
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NCA4 2017–2018 Fourth National Climate Assessment
NEI National Emissions Inventory
NEMS National Energy Modeling System
NESHAP National Emissions Standards for Hazardous Air Pollutants
NGL natural gas liquid
NGO non-governmental organization
NOAA National Oceanic and Atmospheric Administration
NO_X nitrogen oxides
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement Act
OCSLA The Outer Continental Shelf Lands Act
OAQPS Office of Air Quality Planning and Standards
OIG Office of the Inspector General
OGI optical gas imaging
OMB Office of Management and Budget
PE professional engineer
PFCs perfluorocarbons
PHMSA Pipeline and Hazardous Materials Safety Administration
PM particulate matter
$PM_{2.5}$ PM with a diameter of 2.5 micrometers or less
ppb parts per billion
ppm parts per million
PRA Paperwork Reduction Act
PRD pressure release device
PRV pressure release valve
PSD Prevention of Significant Deterioration
psig pounds per square inch gauge
PTE potential to emit
PV present value
REC reduced emissions completion
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
RTC response to comments
SBAR Small Business Advocacy Review
SC-CH_4 social cost of methane
SCF significant contribution finding
scf standard cubic feet
scfh standard cubic feet per hour
scfm standard cubic feet per minute
SF_6 sulfur hexafluoride
SIP State Implementation Plan
SO_2 sulfur dioxide
SO_X sulfur oxides
tpy tons per year
D.C. Circuit U.S. Court of Appeals for the District of Columbia Circuit
TAR Tribal Authority Rule
TIP Tribal Implementation Plan
TSD technical support document
TTN Technology Transfer Network
UAS unmanned aircraft systems
UIC underground injection control
UMRA Unfunded Mandates Reform Act
U.S. United States
USGCRP U.S. Global Change Research Program
USGS U.S. Geologic Survey
VCS Voluntary Consensus Standards
VOC volatile organic compounds
VRD vapor recovery device
VRU vapor recovery unit

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

I. Executive Summary

A. Purpose of the Regulatory Action

This proposed rulemaking takes a significant step forward in mitigating climate-destabilizing pollution and protecting human health by reducing GHG and VOC emissions from the Oil and Natural Gas Industry,[1] specifically the Crude Oil and Natural Gas source category.[2] 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 Oil and Natural Gas Industry also emits other harmful pollutants in varying concentrations and amounts, including carbon dioxide (CO_2), VOC, sulfur dioxide (SO_2), nitrogen oxide (NO_X), hydrogen sulfide (H_2S), carbon disulfide (CS_2), and carbonyl sulfide (COS), as well as benzene, toluene, ethylbenzene, and xylenes (this group is commonly referred to as ''BTEX''), and n-hexane.

Under the authority of CAA section 111, this rulemaking proposes comprehensive standards of performance for GHG emissions (in the form of methane limitations) and VOC emissions for new, modified, and reconstructed sources in the Crude Oil and Natural Gas source category, including the production, processing, transmission and storage segments. For designated facilities,[3] this rulemaking proposes EG containing presumptive standards for GHG in the form of methane limitations. When finalized, States shall utilize these EG to submit to the EPA plans that establish standards of performance for designated facilities and provide for implementation and enforcement of such standards. The EPA will provide support for States in developing their plans to reduce methane emissions from designated facilities within the Crude Oil and Natural Gas source category.

The EPA is proposing these actions in accordance with its legal obligations and authorities following a review directed by E.O. 13990, ''Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis,'' issued on January 20, 2021. The EPA intends for these proposed actions to address the far-reaching harmful consequences and real economic costs of climate change. According to the IPCC AR6 assessment, ''It is unequivocal that human influence has warmed the atmosphere, ocean and land. Widespread and rapid changes in the atmosphere, ocean, cryosphere and biosphere have occurred.'' The IPCC AR6 assessment states these changes have led to increases in heat waves and wildfire weather, reductions in air quality, more intense hurricanes and

[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. 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''.

[3] The term ''designated facility'' means ''any existing facility which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility.'' See 40 CFR 60.21a(b).

rainfall events, and rising sea level. These changes, along with future projected changes, endanger the physical survival, health, economic well-being, and quality of life of people living in the United States (U.S.), especially those in the most vulnerable communities.

Methane is both the main component of natural gas and a potent GHG. One ton of methane in the atmosphere has 80 times the warming impact of a ton of CO_2, and contributes to the creation of ground-level ozone which is another greenhouse gas. Because methane has a shorter lifetime than CO_2, it has a smaller relative impact—although still significantly greater than CO_2—when considering longer time periods. One standard metric is the 100-year global warming potential (GWP), which is a measure of the climate impact of emissions of one ton a greenhouse gas over 100 years relative to the impact of the emissions of one ton of CO_2. Even over this long timeframe, methane has a 100-year GWP of almost 30. The IPCC AR6 assessment found that ''Over time scales of 10 to 20 years, the global temperature response to a year's worth of current emissions of SLCFs (short lived climate forcer) is at least as large as that due to a year's worth of CO_2 emissions.'' [4] The IPCC estimated that, depending on the reference scenario, collective reductions in these SLCFs (methane, ozone precursors, and HFCs) could reduce warming by 0.2 degrees Celsius (°C) (more than one-third of a degree Fahrenheit (°F) in 2040 and 0.8 °C (almost 1.5 °F) by the end of the century, which is important in the context of keeping warming to well below 2 °C (3.6 °F). As methane is the most important SLCF, this makes methane mitigation one of the best opportunities for reducing near term warming. Emissions from human activities have already more than doubled atmospheric methane concentrations since 1750, and that concentration has been growing larger at record rates in recent years.[5] In the absence of additional reduction policies, methane emissions are projected to continue rising through at least 2040.

Methane's radiative efficiency means that immediate reductions in methane emissions, including from sources in the Crude Oil and Natural Gas source category, can help reduce near-term warming. As natural gas is comprised primarily of methane, every natural gas leak, or intentional release of natural gas through venting or other processes, constitutes a release of methane. Reducing human-caused methane emissions, such as controlling natural gas leaks and releases as proposed in these actions, would contribute substantially to global efforts to limit temperature rise, aiding efforts to remain well below 2 °C above pre-industrial levels. See preamble section III for further discussion on the Crude Oil and Natural Gas Emissions and Climate Change, including discussion of the GHGs, VOCs, and SO_2 Emissions on Public Health and Welfare.

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 does not seat properly at the end of an automated liquid dumping event, inefficient separation of gas and liquid phases occurs 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 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. But 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 reducing multiple pollutants at once and recovering saleable product. These technologies and best practices have been deployed by individual oil and natural gas companies, required by State regulations, or reflected in regulations issued by the EPA and other Federal agencies.

In this action, the EPA has taken 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 emissions, consistent with the requirements of section 111 of the CAA. If finalized and implemented, the actions proposed in this rulemaking would lead to significant and cost-effective reductions in climate and health-harming pollution and encourage development and deployment of innovative technologies to further reduce this pollution in the Crude Oil and Natural Gas source category. The actions proposed in this rulemaking would:

- Update, strengthen, and expand current requirements under CAA section 111(b) for methane and VOC emissions from new, modified, and reconstructed facilities,
- establish new limits for methane, and VOC emissions from new, modified, and reconstructed facilities that are not currently regulated under CAA section 111(b),
- establish the first nationwide EG for States to limit methane pollution from existing designated facilities in the source category under CAA section 111(d), and
- take comment on additional sources of pollution that, with understanding gained from more information, may offer opportunities for emission reductions, which the EPA would present in a supplemental rulemaking proposal under both CAA section 111(b) and (d).

In developing this proposal, the EPA drew on its own prior experience in regulating sources in the Crude Oil and Natural Gas source category under section 111 and other CAA programs; applied lessons learned from States' regulatory efforts, the emission reduction efforts of leading companies, and the EPA's long-standing voluntary emission reduction programs; and reviewed the latest available information about new and developing technologies, as well as, peer-reviewed research from emission measurement campaigns across the U.S. Further, the EPA undertook extensive pre-proposal outreach to the public and to stakeholders, including three full days

[4] However, the IPCC AR6 assessment cautioned that ''The effects of the SLCFs decay rapidly over the first few decades after pulse emission. Consequently, on time scales longer than about 30 years, the net long-term temperature effects of sectors and regions are dominated by CO_2.''

[5] Naik, V., S. Szopa, B. Adhikary, P. Artaxo, T. Berntsen, W.D. Collins, S. Fuzzi, L. Gallardo, A. Kiendler 41 Scharr, Z. Klimont, H. Liao, N. Unger, P. Zanis, 2021, Short-Lived Climate Forcers. In: Climate Change 42 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the 43 Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. 44 Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. 45 Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu and B. Zhou (eds.)]. Cambridge University 46 Press. In Press.

of public listening sessions, roundtables with State energy and environmental regulators, a two-day workshop on innovative methane detection technologies, and a nonregulatory docket established in May 2021 to receive written comments. Through this outreach, the EPA heard from diverse voices and perspectives including State and local governments, Tribal nations, communities affected by oil and gas pollution, environmental and public health organizations, and representatives of the oil and natural gas industry, all of which provided ideas and information that helped shape and inform this proposal.

The EPA also considered community and environmental justice implications in the development of this proposal and sought to ensure equitable treatment and meaningful involvement of all people regardless of race, color, national origin, or income in the process. The EPA engaged and consulted representatives of frontline communities that are directly affected by and particularly vulnerable to the climate and health impacts of pollution from this source category through interactions such as webinars, listening sessions and meetings. These opportunities allowed the EPA to hear directly from the public, especially overburdened and underserved communities, on the development of the proposed rule and to factor these concerns into this proposal. For example, in addition to establishing EG that extend fugitive emission requirements to existing oil and natural gas facilities, the EPA is proposing to expand leak detection programs already in effect for new sources to include known sources of large emission events and proposing to require more frequent monitoring at sites with more emissions. The EPA is also taking comment on innovative mechanisms to ensure compliance and minimize emissions, including the possibility of providing a pathway for communities to detect and report large emitting events that may require follow-up and mitigation by owners and operators. The extensive pollution reduction measures in this proposal, if finalized, would collectively reduce a suite of harmful pollutants and their associated health impacts in communities adjacent to these emission sources. Further, to help ensure that the needs and perspectives of communities with environmental justice concerns are considered as States develop plans to establish and implement standards of performance for existing sources, the EPA is proposing to require that States demonstrate they have undertaken meaningful outreach and engagement with overburdened and underserved communities as part of their State plan submissions under the EPA. A full discussion of the Environmental Justice Considerations, Implications, and Stakeholder Outreach can be found in section VI of the preamble. A full discussion of Other Stakeholder Outreach is found in section VII of the preamble.

As described in more detail below, the EPA recognizes that several States and other Federal agencies currently regulate the Oil and Natural Gas Industry. The EPA also recognizes that these State and other Federal agency regulatory programs have matured since the EPA began implementing the current NSPS requirements in 2012 and 2016. The EPA further acknowledges the technical innovations that the Oil and Natural Gas Industry has made during the past decade; this industry operates at a fast pace and changes constantly as technology evolves. The EPA commends these efforts and recognizes States for their innovative standards, alternative compliance options, and implementation strategies, and intends these proposed actions to build upon progress made by certain States and Federal agencies in reducing GHG and VOC emissions. See preamble section V for fuller discussion of Related State Actions and Other Federal Actions Regulating Oil and Natural Gas Sources and Industry and Voluntary Actions to Address Climate Change.

The EPA believes that a broad ensemble of mutually leveraging efforts across all States and all Federal agencies is essential to meaningfully address climate change effectively. As the Federal agency with primary responsibility to protect human health and the environment, the EPA has the unique responsibility and authority to regulate harmful air pollutants emitted by the Crude Oil and Natural Gas source category. The EPA recognizes that States and other Federal agencies regulate in accordance with their respective legal authorities and within their respective jurisdictions but collectively do not fully and consistently address the range of sources and emission reduction measures contained in this proposal. Direct Federal regulation of methane from new, reconstructed, and modified sources in this category, combined with approved State plans that are consistent with the EPA's presumptive standards for designated facilities (existing sources), will help reduce both climate- and other health-harming pollution from a large number of sources that are either unregulated or from which additional, cost-effective reductions are available, level the regulatory playing field, and help promote technological innovation.

Throughout this action, unless noted otherwise, the EPA is requesting comments on all aspects of the 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. As a further step in the rulemaking process and to solicit additional public input, the EPA plans to issue a supplemental proposal and supplemental RIA for the supplemental proposal to provide regulatory text for the proposed NSPS OOOOb and EG OOOOc. In light of certain innovative elements of this proposed rule and the EPA's request for information that would support the regulation of additional sources in the Crude Oil and Natural Gas source category as part of this rulemaking, the EPA is considering including additional provisions in this supplemental proposal and RIA based on information and comment collected in response to this document.

As noted later in this preamble, the supplemental proposal may address, among other issues: (1) Ways to mitigate methane from abandoned wells, (2) measures to reduce emissions from pipeline pigging operations and other pipeline blowdowns, (3) ways to minimize emissions from tank truck loading operations, and (4) ways to strengthen requirements to ensure proper operation and optimal performance of control devices. In addition, and as noted in the solicitations of comment in this document, the supplemental proposal may revisit and refine certain provisions of this proposal in response to information provided by the public. For instance, the EPA is seeking input 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; the methodology for calculating baseline methane emissions and whether it should account for malfunctions or improper operation of controls at storage vessels; and ways to ensure that emissions from wells owned by small businesses are addressed while still recognizing the greater challenges that small businesses with less dedicated staff and resources for environmental compliance may have. The EPA is also seeking input on ways to ensure that captured associated gas is collected for a useful purpose rather than flared, and the feasibility of requiring broader use of zero-emitting technology for pneumatic pumps.

Finally, the EPA is seeking comment and information on alternative measurement technologies, which we are proposing to allow in the rule. We have heard strong interest from various stakeholders on employing new tools for methane identification and quantification, particularly for large emission sources (commonly known as ''super-emitters''). Information provided in response to this proposal may be used to evaluate whether a change in BSER from the proposed quarterly OGI monitoring to a monitoring program using alternative measurement technologies is appropriate. Separate from the role of these alternative measurement technologies in a regulatory monitoring program, we are also soliciting comment on ways to structure a pathway for communities to identify large emission events which owners or operators would then be required to investigate, and mechanisms for the collection and public dissemination of this information, for possible further development as part of a supplemental proposal.

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—Proposed Rule Summary of Comment Solicitations.''

B. Summary of the Major Provisions of This Regulatory Action

This proposed rulemaking includes three distinct groups of actions under the CAA that are each severable from the other. First, pursuant to CAA 111(b)(1)(B), the EPA has reviewed, and is proposing revisions to, the standards of performance for the Crude Oil and Natural Gas source category published in 2016 and amended in 2020, codified at 40 CFR part 60, subpart OOOOa—*Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015* (2016 NSPS OOOOa). Specifically, the EPA is proposing to update, strengthen, and expand the current 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 standards of performance will be in a new subpart, 40 CFR part 60, subpart OOOOb (NSPS OOOOb), and include standards for emission sources previously not regulated under the 2016 NSPS OOOOa.

Second, pursuant to CAA 111(d), the EPA is proposing the first nationwide EG for States to limit methane pollution from designated facilities in the Crude Oil and Natural Gas source category. The EG being proposed in this rulemaking will be in a new subpart, 40 CFR part 60, subpart OOOOc (EG OOOOc). The 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 from their designated facilities in the Crude Oil and Natural Gas source category.

Third, the EPA is taking several related actions stemming from the joint resolution of Congress, adopted on June 30, 2021 under the CRA, disapproving the EPA's final rule titled, ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review,'' 85 FR 57018 (Sept. 14, 2020) (''2020 Policy Rule''). As explained in Section X of this action (Summary of Proposed Action for NSPS OOOOa), the EPA is proposing amendments to the 2016 NSPS OOOOa to address (1) certain inconsistencies between the VOC and methane standards resulting from the disapproval of the 2020 Policy Rule, and (2) certain determinations made in the final rule titled ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration,'' 85 FR 57398 (September 15, 2020) (2020 Technical Rule), specifically with respect to fugitive emissions monitoring at low production well sites and gathering and boosting stations. With respect to the latter, as described below, the EPA is proposing to rescind provisions of the 2020 Technical Rule that were not supported by the record for that rule, or by our subsequent information and analysis. The regulatory text for these proposed amendments is included in the docket for this rulemaking at Docket ID EPA–HQ–OAR–2021–0317.

In addition, in the final rule for this action, the EPA will update the NSPS OOOO and NSPS OOOOa provisions in the Code of Federal Regulations (CFR) to reflect the Congressional Review Act (CRA) resolution's disapproval of the final 2020 Policy Rule, specifically, the reinstatement of the NSPS OOOO and NSPS OOOOa requirements that the 2020 Policy Rule repealed but that came back into effect immediately upon enactment of the CRA resolution. It should be noted that these requirements have come back into effect already even though the EPA has not yet updated the CFR text to reflect them.[6] These updates to the CFR text are also included in the docket for this rulemaking at Docket ID EPA–HQ–OAR–2021–0317 for public awareness, but the EPA is not soliciting comment on them as they merely reflect current law. Under 5 U.S.C. 553(b)(3)(B), notice and comment is not required ''when the agency for good cause finds . . . that notice and public procedure thereon are . . . unnecessary . . . ,'' [7] and, as just noted, notice and comment is not necessary for these updates. The EPA is waiting to make these updates to the CFR text until the final rule simply because it would be more efficient and clearer to amend the CFR once at the end of this rulemaking process to account for all changes to the 2012 NSPS OOOO (77 FR 49490, August 16, 2012) and 2016 NSPS OOOOa at the same time.

As CAA section 111(a)(1) requires, the standards of performance 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.'' This action further proposes EG for designated facilities, under which States must submit plans which establish standards of performance that reflect the degree of emission limitation achievable through application of the BSER, as identified in the final EG. In this proposed rulemaking, we evaluated potential control measures available for the affected facilities, the emission reductions achievable through these measures, and employed multiple approaches to evaluate the reasonableness of control costs associated with the options under

[6] See Congressional Review Act Resolution to Disapprove EPA's 2020 Oil and Gas Policy Rule Questions and Answers (June 30, 2021) available at *https://www.epa.gov/system/files/documents/2021-07/qa_cra_for_2020_oil_and_gas_policy_rule.6.30.2021.pdf.*

[7] 5 U.S.C. 553(b)(3)(B) is applicable to rules promulgated under CAA section 111(b), under CAA section 307(d)(1) (flush language at end).

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 consider that the systems of emission reduction considered in this rule typically achieve reductions in multiple pollutants at once and secure a multiplicity of climate and public health benefits. For a detailed discussion of the EPA's consideration of this and other BSER statutory elements, please see sections IV and IX of this preamble.

TABLE 1—APPLICABILITY 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.
40 CFR part 60, subpart OOOOc	Existing sources	On or before November 15, 2021.

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

As described in sections XI and XII of this preamble, under the authority of CAA section 111(b)(1)(B) the EPA has reviewed the VOC, GHG (in the form of limitations on methane), and SO_2 standards in the 2016 NSPS OOOOa (as amended in 2020 by the Technical Rule). Based on its review, the EPA is proposing revisions to the standards for certain emissions sources to reflect the updated BSER for those affected sources. Where our analyses show that the BSER for an affected source remains the same, the EPA is proposing to retain the current standard for that affected source. In addition, the EPA is proposing methane and VOC standards for several new sources that are currently unregulated. The proposed NSPS described above 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 revisions to the NSPS. In particular, this action proposes to retain the 2016 NSPS OOOOa SO_2 performance standard for sweetening units and the 2016 OOOOa VOC and methane performance standards for well completions and centrifugal compressors; proposes revisions to strengthen the 2016 NSPS OOOOa VOC and methane standards addressing fugitive emissions from well sites and compressor stations, storage vessels, pneumatic controllers, reciprocating compressors, pneumatic pumps, and equipment leaks at natural gas processing plants; and proposes new VOC and methane standards for well liquids unloading operations and intermittent vent pneumatic controllers, and oil wells with associated gas previously not regulated in the 2016 NSPS OOOOa. A summary of the proposed BSER determination and proposed NSPS for new, modified, and reconstructed sources (NSPS OOOOb) is presented in Table 2. See sections XI and XII of this preamble for a complete discussion of BSER determination and proposed NSPS requirements.

This proposal also solicits certain information relevant to the potential identification of additional emissions sources as affected facilities. Specifically, the EPA is evaluating the potential for establishing standards for abandoned and unplugged wells, blowdown emissions associated with pipeline pig launchers and receivers, and tank truck loading operations. While the EPA has assessed these sources based on currently available information, we have determined that we need additional information to evaluate BSER and to propose NSPS for these emissions sources. A full discussion of the solicitation for comment regarding these additional emission sources is found in section XIII of the preamble.

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

As described in sections XI and XII of this preamble, under the authority of CAA section 111(d), the EPA is proposing 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). 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 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 action, the EPA is proposing 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. Section XIV 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 believes 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 XI and XII of this preamble for a complete discussion of the proposed EG requirements.

As discussed above for the proposed NSPS OOOOb, the EPA is considering including additional sources as affected facilities in a potential future supplemental rulemaking proposal[9] under CAA section 111(b). The EPA is also considering including these additional sources as designated facilities under the EG in OOOOc in a potential future supplemental rulemaking proposal under CAA section 111(d). As with the proposed NSPS OOOOb, the EPA is evaluating the potential for establishing EG applicable to abandoned and unplugged wells, blowdown emissions associated with pipeline pig launchers and receivers, and tank truck loading operations (assuming the EPA establishes NSPS for these emissions points). As described in section XIII of this preamble, the EPA is soliciting information to assist in this effort.

3. Proposed Amendments to 2016 NSPS OOOOa, and CRA-Related CFR Updates

The EPA is also proposing certain modifications to the 2016 NSPS OOOOa to address certain amendments to the VOC standards for sources in the production and processing segments finalized in the 2020 Technical Rule. Because the methane standards for the production and processing segments and all standards for the transmission and storage segment were removed from the 2016 NSPS OOOOa via the 2020 Policy Rule prior to the finalization of the 2020 Technical Rule, the latter amendments apply only to the 2016 NSPS OOOOa VOC standards for the production and processing segments. In this proposed rulemaking, the EPA also is proposing to apply some of the 2020 Technical Rule amendments to the methane standards for all industry segments and to VOC standards for the transmission and storage segment in the 2016 NSPS OOOOa. These amendments are associated with the requirements for well completions, pneumatic pumps, closed vent systems, fugitive emissions, alternative means of emission limitation (AMELs), onshore natural gas processing plants, as well as other technical clarifications and corrections. The EPA also is proposing to repeal the amendments in the 2020 Technical Rule that (1) exempted low production well sites from monitoring fugitive emissions and (2) changed monitoring of VOC emissions at gathering and boosting compressor stations from quarterly to semiannual, which currently apply only to VOC standards (not methane standards) from the production and processing segments. A summary of the proposed amendments to the 2016 OOOOa NSPS is presented in section X of this preamble.

Lastly, in the final rule for this action, the EPA will update the NSPS OOOO and OOOOa provisions in the CFR to reflect the CRA resolution's disapproval of the final 2020 Policy Rule, specifically, the reinstatement of the OOOO and OOOOa requirements that the 2020 Policy Rule repealed but that came back into effect immediately upon enactment of the CRA resolution. The EPA is waiting to make the updates to the CFR text until the final rule simply because it would be more efficient and clearer to amend the CFR once at the end of this rulemaking process to account for all changes to the 2012 NSPS OOOO and 2016 NSPS OOOOa at the same time. In accordance with 5 U.S.C. 553(b)(3)(B), the EPA is not soliciting comment on these updates.

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

Affected source	Proposed BSER	Proposed standards of performance for GHGs and VOCs
Fugitive Emissions: Well Sites with Baseline Emissions >0 to <3 tpy[1] Methane.	Demonstrate actual site emissions are reflected in calculation.	Perform survey to verify that actual site emissions are reflected in calculation.
Fugitive Emissions: Well Sites ≥3 tpy Methane.	Monitoring and repair based on quarterly monitoring using OGI[2].	Quarterly OGI monitoring following appendix K. (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.
(Co-proposal) Fugitive Emissions: Well Sites with Baseline Emissions ≥3 to <8 tpy Methane.	Monitoring and repair based on semiannual monitoring using OGI.	Semiannual OGI monitoring following appendix K. (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.

[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 XIV.F. for information on Federal plans.

[9] A supplemental proposal would include an updated RIA.

TABLE 2—SUMMARY OF PROPOSED BSER AND PROPOSED STANDARDS OF PERFORMANCE FOR GHGS AND VOC—Continued

[NSPS OOOOb]

Affected source	Proposed BSER	Proposed standards of performance for GHGs and VOCs
(Co-proposal) Fugitive Emissions: Well Sites with Baseline Emissions ≥8 tpy Methane.	Monitoring and repair based on quarterly monitoring using OGI.	Quarterly OGI monitoring following appendix K. (Optional quarterly EPA Method 21 monitoring with 500 ppm [3] 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: Compressor Stations	Monitoring and repair based on quarterly monitoring using OGI.	Quarterly OGI monitoring following appendix K. (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 following appendix K. (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 bimonthly screening using an advanced measurement technology and annual monitoring using OGI.	(Optional) Alternative bimonthly screening with advanced measurement technology with annual OGI monitoring following appendix K.
Storage Vessels: A Single Storage Vessel or Tank Battery with PTE [4] of 6 tpy or More of VOC.	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).	Installation 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	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.	Each affected well that unloads liquids employ techniques or technology(ies) that eliminate or minimize venting of emissions during liquids unloading events to the maximum extent. Co Proposal Options: *Option One*—Affected facility would be defined as every well that undergoes liquids unloading. —If the method is one that does not result in any venting to the atmosphere, maintain records specifying the technology or technique and record instances where an unloading event results in emissions. —For unloading technologies or techniques that result in venting to the atmosphere, implement BMPs [6] to ensure that venting is minimized. —Maintain BMPs as records, and record instances when they were not followed. *Option Two*—Affected facility would be defined as every well that undergoes liquids unloading using a method that is not designed to eliminate venting. —Wells that utilize non-venting methods would not be affected facilities that are subject to the NSPS OOOOb. Therefore, they would not have requirements other than to maintain records to document that they used non-venting liquids unloading methods. —The requirements for wells that use methods that vent would be the same as described above under Option 1.
Wet Seal Centrifugal Compressors (except for those located at single well sites).	Capture and route emissions from the wet seal fluid degassing system to a control device or to a process.	Reduce emissions by 95 percent.
Reciprocating Compressors (except for those located at single well sites).	Replace the reciprocating compressor rod packing based on annual monitoring (when measured leak rate exceeds 2 scfm [7]) or route emissions to a process.	Replace the reciprocating compressor rod packing when measured leak rate exceeds 2 scfm based on the results of annual monitoring or collect and route emissions from the rod packing to a process through a closed vent system under negative pressure.

TABLE 2—SUMMARY OF PROPOSED BSER AND PROPOSED STANDARDS OF PERFORMANCE FOR GHGS AND VOC—Continued

[NSPS OOOOb]

Affected source	Proposed BSER	Proposed standards of performance for GHGs and VOCs
Pneumatic Pumps: Natural Gas Processing Plants.	A natural gas emission rate of zero	A natural gas emission rate of zero from diaphragm and piston pneumatic pumps.
Pneumatic Pumps: Production Segment	Route diaphragm and piston pneumatic pumps to an existing control device or process.	95 percent control of diaphragm and piston pneumatic pumps if there is an existing control or process on site. 95 percent control not required if (1) routed to an existing control that achieves less than 95 percent or (2) it is technically infeasible to route to the existing control device or process.
Pneumatic Pumps: Transmission and Storage Segment.	Route diaphragm pneumatic pumps to an existing control device or process.	95 percent control of diaphragm pneumatic pumps if there is an existing control or process on site. 95 percent control not required if (1) routed to an existing control that achieves less than 95 percent or (2) it is technically infeasible to route to the existing control device or process.
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 safety hazards. Initial flowback stage: Route to a storage vessel or completion vessel (frac tank, lined pit, or other vessel) and separator. Separation flowback stage: Route all salable gas from the separator to a flow line or collection system, re-inject the gas into the well or another well, use the gas as an onsite fuel source or use for another useful purpose that a purchased fuel or raw material would serve. If technically infeasible to route recovered gas as specified above, recovered gas must be combusted. All liquids must be routed to a storage vessel or well completion vessel, collection system, or be re-injected into the well or another well. The operator is required to have (and use) a separator onsite during the entire flowback period.
Well Completions: Subcategory 2 (exploratory 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, 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.
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
Fugitive Emissions: Well Sites >0 to <3 tpy Methane.	Demonstrate actual site emissions are reflected in calculation.	Perform survey to verify that actual site emissions are reflected in calculation.
Fugitive Emissions: Well Sites ≥3 tpy Methane.	Monitoring and repair based on quarterly monitoring using OGI.	Quarterly OGI monitoring following appendix K. (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.
(Co-proposal) Fugitive Emissions: Well Sites ≥3 to <8 tpy Methane.	Monitoring and repair based on semi-annual monitoring using OGI.	Semiannual OGI monitoring following appendix K. (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.
(Co-proposal) Fugitive Emissions: Well Sites ≥8 tpy Methane.	Monitoring and repair based on quarterly monitoring using OGI.	Quarterly OGI monitoring following appendix K. (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: Compressor Stations	Monitoring and repair based on quarterly monitoring using OGI.	Quarterly OGI monitoring following appendix K. (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 following appendix K. (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 bimonthly screening using an advanced measurement technology and annual monitoring using OGI.	(Optional) Alternative bimonthly screening with advanced measurement technology with annual OGI monitoring following appendix K.
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	VOC and methane emission rate of zero.
Pneumatic Controllers: Alaska (at sites where onsite power is not available—continuous bleed natural gas driven).	Installation 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.
Wet Seal Centrifugal Compressors (except for those located at single well sites).	Capture and route emissions from the wet seal fluid degassing system to a control device or to a process.	Reduce emissions by 95 percent.
Reciprocating Compressors (except for those located at single well sites).	Replace the reciprocating compressor rod packing based on annual monitoring (when measured leak rate exceeds 2 scfm) or route emissions to a process.	Replace the reciprocating compressor rod packing when measured leak rate exceeds 2 scfm based on the results of annual monitoring, or collect and route emissions from the rod packing to a process through a closed vent system under negative pressure.
Pneumatic Pumps: Natural Gas Processing Plants.	A natural gas emission rate of zero	Zero natural gas emissions from diaphragm and piston pneumatic pumps.
Pneumatic Pumps: Locations Other Than Natural Gas Processing Plants.	Route diaphragm pumps to an existing control device or process.	95 percent control of diaphragm pneumatic pumps if there is an existing control or process on site. 95 percent control not required if (1) routed to an existing control that achieves less than 95 percent or (2) it is technically infeasible to route to the existing control device or process.
Equipment Leaks at Natural Gas Processing Plants.	LDAR with bimonthly OGI	LDAR with OGI following procedures in appendix K.

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

[EG OOOOc]

Designated facility	Proposed BSER	Proposed presumptive standards 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, 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, 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.

C. Costs and Benefits

To satisfy requirements of E.O. 12866, the EPA projected the emissions reductions, costs, and benefits that may result from this proposed action. These results are presented in detail in the regulatory impact analysis (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 without the proposal that incorporates changes to regulatory requirements induced by the CRA resolution. 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 towards the end of 2022. 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 three years, and so EG impacts will begin in 2026. The final analysis year is 2035, which allows us to provide ten 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 global social benefits of CH_4 emission reductions expected from this proposed rule using the SC-CH_4 estimates presented in the ''Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under E.O. 13990 (IWG 2021)''. These SC-CH_4 estimates are interim values developed under E.O. 13990 for use in benefit-cost analyses until updated estimates of the impacts of climate change can be developed based on the best available science and economics.

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, $PM_{2.5}$, 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 B 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.

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

Pollutant	Emissions reductions (2023–2035 total)
Methane (million short tons) [a]	41
VOC (million short tons)	12
Hazardous Air Pollutant (million short tons)	0.48

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

Pollutant	Emissions reductions (2023–2035 total)
Methane (million metric tons CO_2 Eq.) [b]	920

[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] CO_2 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]

	3 percent discount rate		7 percent discount rate	
	Present value	Equivalent annual value	Present value	Equivalent annual value
Climate Benefits [b]	$55,000	$5,200		
Net Compliance Costs	7,200	680	6,300	760
Compliance Costs	13,000	1,200	10,000	1,200
Product Recovery	5,500	520	3,900	470
Net Benefits	48,000	4,500	49,000	4,500
Non-Monetized Benefits	Climate and ozone health benefits from reducing 41 million short tons of methane from 2023 to 2035. $PM_{2.5}$ and ozone health benefits from reducing 12 million short tons of VOC from 2023 to 2035 [c]. HAP benefits from reducing 480 thousand short tons of HAP from 2023 to 2035. 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 social cost of methane (SC-CH_4) (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-CH_4 at a 3 percent discount rate, but the Agency does not have a single central SC-CH_4 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; the present value (and equivalent annual value) of the additional benefit estimates ranges from $22 billion to $150 billion ($2.4 billion to $14 billion) over 2023 to 2035 for the proposed option. Please see Table 3–5 and Table 3–7 of the RIA for the full range of SC-CH_4 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. 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 B 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	Crude Petroleum Extraction.
	211130	Natural Gas Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	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 final rule and key technical documents at this same website. A redline version of the regulatory language that incorporates the proposed changes described in section X for NSPS OOOO and NSPS OOOOa is available in the docket for this action (Docket ID No. EPA–HQ–OAR–2021–0317). The EPA plans to propose the regulatory language for NSPS OOOOb and EG OOOOc through a supplemental action.

III. Air Emissions From the Crude Oil and Natural Gas Sector and Public Health and Welfare

A. Impacts of GHGs, VOCs and SO_2 Emissions on Public Health and Welfare

As noted previously, the Oil and Natural Gas Industry emits a wide range of pollutants, including GHGs (such as methane and CO_2), VOCs, SO_2, NO_X, H_2S, CS_2, and COS. See 49 FR 2636, 2637 (January 20, 1984). As noted below, to this point, the EPA has focused its regulatory efforts on GHGs, VOC, and SO_2.[10]

1. Climate Change Impacts From GHGs Emissions

Elevated concentrations of GHGs are and have been warming the planet, leading to changes in the Earth's climate including changes in the frequency and intensity of heat waves, precipitation, and extreme weather events; rising seas; and retreating snow and ice. The changes taking place in the atmosphere as a result of the well-documented buildup of GHGs due to human activities are changing the climate at a pace and in a way that threatens human health, society, and the natural environment. Human induced GHGs, largely derived from our reliance on fossil fuels, are causing serious and life-threatening environmental and health impacts.

Extensive additional information on climate change is available in the scientific assessments and the EPA documents that are briefly described in this section, as well as in the technical and scientific information supporting them. One of those documents is the EPA's 2009 *Endangerment and Cause or Contribute Findings for GHGs Under Section 202(a)* of the CAA (74 FR 66496, December 15, 2009).[11] In the 2009 Endangerment Findings, the Administrator found under section 202(a) of the CAA that elevated atmospheric concentrations of six key well-mixed GHGs—CO_2, CH_4, N_2O, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—''may reasonably be anticipated to endanger the public health and welfare of current and future generations'' (74 FR 66523, December 15, 2009), and the science and observed changes have confirmed and strengthened the understanding and concerns regarding the climate risks considered in the Finding. The 2009 Endangerment Findings, together with the extensive scientific and technical evidence in the supporting record, documented that climate change caused by human emissions of GHGs threatens the public health of the U.S. population. It explained that by raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses (74 FR 66497, December 15, 2009). While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the U.S. (74 FR 66525, December 15, 2009). The 2009 Endangerment Findings further explained that compared to a future without climate change, climate change is expected to increase tropospheric ozone pollution over broad areas of the U.S., including in the largest metropolitan areas with the worst tropospheric ozone problems, and thereby increase the risk of adverse effects on public health (74 FR 66525, December 15, 2009). Climate change is also expected to cause more intense hurricanes and more frequent and intense storms of other types and heavy precipitation, with impacts on other areas of public health, such as the potential for increased deaths, injuries, infectious and waterborne diseases, and stress-related disorders (74 FR 66525, December 15, 2009). Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects (74 FR 66498, December 15, 2009).

The 2009 Endangerment Findings also documented, together with the extensive scientific and technical evidence in the supporting record, that climate change touches nearly every aspect of public welfare[12] in the U.S. with resulting economic costs, including: Changes in water supply and quality due to increased frequency of drought and extreme rainfall events; increased risk of storm surge and flooding in coastal areas and land loss due to inundation; increases in peak electricity demand and risks to electricity infrastructure; and the potential for significant agricultural disruptions and crop failures (though offset to some extent by carbon fertilization). These impacts are also global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S. (74 FR 66530, December 15, 2009).

In 2016, the Administrator similarly issued Endangerment and Cause or Contribute Findings for GHG emissions from aircraft under section 231(a)(2)(A) of the CAA (81 FR 54422, August 15, 2016).[13] In the 2016 Endangerment Findings, the Administrator found that the body of scientific evidence amassed in the record for the 2009 Endangerment Findings compellingly supported a similar endangerment finding under CAA section 231(a)(2)(A), and also found that the science assessments released between the 2009 and the 2016 Findings, ''strengthen and further support the judgment that GHGs in the atmosphere may reasonably be anticipated to endanger the public health and welfare of current and future generations.'' (81 FR 54424, August 15, 2016).

Since the 2016 Endangerment Findings, the climate has continued to change, with new records being set for several climate indicators such as global average surface temperatures, GHG concentrations, and sea level rise. Moreover, heavy precipitation events

[10] We note that the EPA's focus on GHGs (in particular methane), VOC, and SO_2 in these analyses, does not in any way limit the EPA's authority to promulgate standards that would apply to other pollutants emitted from the Crude Oil and Natural Gas source category, if the EPA determines in the future that such action is appropriate.

[11] In describing these 2009 Findings in this proposal, the EPA is neither reopening nor revisiting them.

[12] The CAA states in section 302(h) that ''[a]ll language referring to effects on welfare includes, but is not limited to, effects on soils, water, crops, vegetation, manmade materials, animals, wildlife, weather, visibility, and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being, whether caused by transformation, conversion, or combination with other air pollutants.'' 42 U.S.C. 7602(h).

[13] In describing these 2016 Findings in this proposal, the EPA is neither reopening nor revisiting them.

have increased in the eastern U.S. while agricultural and ecological drought has increased in the western U.S. along with more intense and larger wildfires.[14] These and other trends are examples of the risks discussed the 2009 and 2016 Endangerment Findings that have already been experienced. Additionally, major scientific assessments continue to demonstrate advances in our understanding of the climate system and the impacts that GHGs have on public health and welfare both for current and future generations. These updated observations and projections document the rapid rate of current and future climate change both globally and in the U.S. These assessments include:

- U.S. Global Change Research Program's (USGCRP) 2016 Climate and Health Assessment [15] and 2017–2018 Fourth National Climate Assessment (NCA4). [16] [17]
- IPCC's 2018 Global Warming of 1.5 °C,[18] 2019 Climate Change and Land,[19] and the 2019 Ocean and Cryosphere in a Changing Climate [20] assessments, as well as the 2021 IPCC Sixth Assessment Report (AR6).[21]
- The NAS 2016 Attribution of Extreme Weather Events in the Context of Climate Change,[22] 2017 Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide,[23] and 2019 Climate Change and Ecosystems [24] assessments.
- National Oceanic and Atmospheric Administration's (NOAA) annual State of the Climate reports published by the Bulletin of the American Meteorological Society,[25] most recently in August of 2020.
- EPA Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts (2021).[26]

The most recent information demonstrates that the climate is continuing to change in response to the human-induced buildup of GHGs in the atmosphere. These recent assessments show that atmospheric concentrations of GHGs have risen to a level that has no precedent in human history and that they continue to climb, primarily as a result of both historic and current anthropogenic emissions, and that these elevated concentrations endanger our health by affecting our food and water sources, the air we breathe, the weather we experience, and our interactions with the natural and built environments. For example, atmospheric concentrations of one of these GHGs, CO_2, measured at Mauna Loa in Hawaii and at other sites around the world reached 414 ppm in 2020 (nearly 50 percent higher than pre-industrial levels),[27] and has continued to rise at a rapid rate. Global average temperature has increased by about 1.1 degrees Celsius (°C) (2.0 degrees Fahrenheit (°F)) in the 2011–2020 decade relative to 1850–1900.[28] The years 2014–2020 were the warmest seven years in the 1880–2020 record, contributing to the warmest decade on record with a decadal temperature of 0.82 °C (1.48 °F) above the 20th century.[29] [30] The IPCC determined (with medium confidence) that this past decade was warmer than any multi-century period in at least the past 100,000 years.[31] Global average sea level has risen by about 8 inches (about 21 centimeters (cm)) from 1901 to 2018, with the rate from 2006 to 2018 (0.15 inches/year or 3.7 millimeters (mm)/year) almost twice the rate over the 1971 to 2006 period, and three times the rate of the 1901 to 2018 period.[32] The rate of sea level rise over the 20th century was higher than in any other century in at least the last 2,800 years.[33] Higher CO_2 concentrations have led to acidification of the surface ocean in recent decades to an extent unusual in the past 2 million years, with negative impacts on marine organisms that use calcium carbonate to build shells or skeletons.[34] Arctic sea ice extent continues to decline in all months of the year; the most rapid reductions occur in September (very likely almost a 13 percent decrease per decade between 1979 and 2018) and are unprecedented in at least 1,000 years.[35] Human-induced climate change has led to heatwaves and heavy precipitation becoming more frequent and more intense, along with increases in

[14] See later in this section for specific examples. An additional resource for indicators can be found at *https://www.epa.gov/climate-indicators.*

[15] 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.

[16] USGCRP, 2017: *Climate Science Special Report: Fourth National Climate Assessment,* Volume I [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 470 pp, doi: 10.7930/J0J964J6.

[17] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.

[18] IPCC, 2018: *Global Warming of 1.5 °C.* An IPCC Special Report on the impacts of global warming of 1.5 °C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)].

[19] IPCC, 2019: *Climate Change and Land: an IPCC special report on climate change, desertification, land degradation, sustainable land management, food security, and greenhouse gas fluxes in terrestrial ecosystems* [P.R. Shukla, J. Skea, E. Calvo Buendia, V. Masson-Delmotte, H.-O. Pörtner, D.C. Roberts, P. Zhai, R. Slade, S. Connors, R. van Diemen, M. Ferrat, E. Haughey, S. Luz, S. Neogi, M. Pathak, J. Petzold, J. Portugal Pereira, P. Vyas, E. Huntley, K. Kissick, M. Belkacemi, J. Malley, (eds.)].

[20] IPCC, 2019: *IPCC Special Report on the Ocean and Cryosphere in a Changing Climate* [H.-O. Pörtner, D.C. Roberts, V. Masson-Delmotte, P. Zhai, M. Tignor, E. Poloczanska, K. Mintenbeck, A. Alegría, M. Nicolai, A. Okem, J. Petzold, B. Rama, N.M. Weyer (eds.)].

[21] IPCC, 2021: *Summary for Policymakers. In: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu and B. Zhou (eds.)]. Cambridge University Press. In Press.

[22] National Academies of Sciences, Engineering, and Medicine. 2016. *Attribution of Extreme Weather Events in the Context of Climate Change.* Washington, DC: The National Academies Press. *https://dio.org/10.17226/21852.*

[23] National Academies of Sciences, Engineering, and Medicine. 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide.* Washington, DC: The National Academies Press. *https://doi.org/10.17226/24651.*

[24] National Academies of Sciences, Engineering, and Medicine. 2019. *Climate Change and Ecosystems.* Washington, DC: The National Academies Press. *https://doi.org/10.17226/25504.*

[25] Blunden, J., and D.S. Arndt, Eds., 2020: State of the Climate in 2019. Bull. Amer. Meteor. Soc, S1–S429, *https://doi.org/10.1175/2020BAMSStateoftheClimate.1.*

[26] EPA. 2021. Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. U.S. Environmental Protection Agency, EPA 430–R–21–003.

[27] *https://climate.nasa.gov/vital-signs/carbon-dioxide/.*

[28] IPCC, 2021.

[29] NOAA National Centers for Environmental Information, State of the Climate: Global Climate Report for Annual 2020, published online January 2021, retrieved on February 10, 2021 from *https://www.ncdc.noaa.gov/sotc/global/202013.*

[30] Blunden, J., and D.S. Arndt, Eds., 2020: State of the Climate in 2019. Bull. Amer. Meteor. Soc, S1–S429, *https://doi.org/10.1175/2020BAMSStateoftheClimate.1.*

[31] IPCC, 2021.

[32] IPCC, 2021.

[33] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.

[34] IPCC, 2021.

[35] IPCC, 2021.

agricultural and ecological droughts [36] in many regions.[37]

The assessment literature demonstrates that modest additional amounts of warming may lead to a climate different from anything humans have ever experienced. The present-day CO_2 concentration of 414 ppm is already higher than at any time in the last 2 million years.[38] If concentrations exceed 450 ppm, they would likely be higher than any time in the past 23 million years:[39] at the current rate of increase of more than 2 ppm a year, this would occur in about 15 years. While GHGs are not the only factor that controls climate, it is illustrative that 3 million years ago (the last time CO_2 concentrations were this high) Greenland was not yet completely covered by ice and still supported forests, while 23 million years ago (the last time concentrations were above 450 ppm) the West Antarctic ice sheet was not yet developed, indicating the possibility that high GHGs concentrations could lead to a world that looks very different from today and from the conditions in which human civilization has developed. If the Greenland and Antarctic ice sheets were to melt substantially, sea levels would rise dramatically—the IPCC estimated that over the next 2,000 years, sea level will rise by 7 to 10 feet even if warming is limited to 1.5 °C (2.7 °F), from 7 to 20 feet if limited to 2 °C (3.6 °F), and by 60 to 70 feet if warming is allowed to reach 5 °C (9 °F) above preindustrial levels.[40] For context, almost all of the city of Miami is less than 25 feet above sea level, and the NCA4 stated that 13 million Americans would be at risk of migration due to 6 feet of sea level rise. Moreover, the CO_2 being absorbed by the ocean has resulted in changes in ocean chemistry due to acidification of a magnitude not seen in 65 million years,[41] putting many marine species—particularly calcifying species—at risk.

The NCA4 found that it is very likely (greater than 90 percent likelihood) that by mid-century, the Arctic Ocean will be almost entirely free of sea ice by late summer for the first time in about 2 million years.[42] Coral reefs will be at risk for almost complete (99 percent) losses with 1 °C (1.8 °F) of additional warming from today (2 °C or 3.6 °F since preindustrial). At this temperature, between 8 and 18 percent of animal, plant, and insect species could lose over half of the geographic area with suitable climate for their survival, and 7 to 10 percent of rangeland livestock would be projected to be lost.[43]

Every additional increment of temperature comes with consequences. For example, the half degree of warming from 1.5 to 2 °C (0.9 °F of warming from 2.7 °F to 3.6 °F) above preindustrial temperatures is projected on a global scale to expose 420 million more people to frequent extreme heatwaves, and 62 million more people to frequent exceptional heatwaves (where heatwaves are defined based on a heat wave magnitude index which takes into account duration and intensity—using this index, the 2003 French heat wave that led to almost 15,000 deaths would be classified as an ''extreme heatwave'' and the 2010 Russian heatwave which led to thousands of deaths and extensive wildfires would be classified as ''exceptional''). It would increase the frequency of sea-ice-free Arctic summers from once in a hundred years to once in a decade. It could lead to 4 inches of additional sea level rise by the end of the century, exposing an additional 10 million people to risks of inundation, as well as increasing the probability of triggering instabilities in either the Greenland or Antarctic ice sheets. Between half a million and a million additional square miles of permafrost would thaw over several centuries. Risks to food security would increase from medium to high for several lower income regions in the Sahel, southern Africa, the Mediterranean, central Europe, and the Amazon. In addition to food security issues, this temperature increase would have implications for human health in terms of increasing ozone concentrations, heatwaves, and vector-borne diseases (for example, expanding the range of the mosquitoes which carry dengue fever, chikungunya, yellow fever, and the Zika virus, or the ticks which carry Lyme. babesiosis, or Rocky Mountain Spotted Fever).[44] Moreover, every additional increment in warming leads to larger changes in extremes, including the potential for events unprecedented in the observational record. Every additional degree will intensify extreme precipitation events by about 7 percent. The peak winds of the most intense tropical cyclones (hurricanes) are projected to increase with warming. In addition to a higher intensity, the IPCC found that precipitation and frequency of rapid intensification of these storms has already increased, while the movement speed has decreased, and elevated sea levels have increased coastal flooding, all of which make these tropical cyclones more damaging.[45]

The NCA4 also evaluated a number of impacts specific to the U.S. Severe drought and outbreaks of insects like the mountain pine beetle have killed hundreds of millions of trees in the western U.S. Wildfires have burned more than 3.7 million acres in 14 of the 17 years between 2000 and 2016, and Federal wildfire suppression costs were about a billion dollars annually.[46] The National Interagency Fire Center has documented U.S. wildfires since 1983, and the ten years with the largest acreage burned have all occurred since 2004.[47] Wildfire smoke degrades air quality increasing health risks, and more frequent and severe wildfires due to climate change would further diminish air quality, increase incidences of respiratory illness, impair visibility, and disrupt outdoor activities, sometimes thousands of miles from the location of the fire. Meanwhile, sea level rise has amplified coastal flooding and erosion impacts, requiring the installation of costly pump stations, flooding streets, and increasing storm surge damages. Tens of billions of dollars of U.S. real estate could be below sea level by 2050 under some scenarios. Increased frequency and duration of drought will reduce agricultural productivity in some regions, accelerate depletion of water supplies for irrigation, and expand the distribution and incidence of pests and diseases for crops and livestock. The NCA4 also recognized that climate change can increase risks to national security, both through direct impacts on military infrastructure, but also by affecting factors such as food and water availability that can exacerbate conflict outside U.S. borders. Droughts, floods, storm surges, wildfires, and other extreme events stress nations and people through loss of life, displacement of populations, and impacts on livelihoods.[48]

Some GHGs also have impacts beyond those mediated through climate change. For example, elevated concentrations of carbon dioxide stimulate plant growth (which can be positive in the case of beneficial species, but negative in terms of weeds and invasive species, and can also lead to a reduction in plant

[36] These are drought measures based on soil moisture.

[37] IPCC, 2021.

[38] IPCC, 2021.

[39] IPCC, 2013.

[40] IPCC, 2021.

[41] IPCC, 2018.

[42] USGCRP, 2018.

[43] IPCC, 2018.

[44] IPCC, 2018.

[45] IPCC, 2021.

[46] USGCRP, 2018

[47] NIFC (National Interagency Fire Center). 2021. Total wildland fires and acres (1983–2020). Accessed August 2021. *www.nifc.gov/fireInfo/fireInfo_stats_totalFires.html.*

[48] USGCRP, 2018.

micronutrients)[49] and cause ocean acidification. Nitrous oxide depletes the levels of protective stratospheric ozone.[50]

As methane is the primary GHG addressed in this proposal, it is relevant to highlight some specific trends and impacts specific to methane. Concentrations of methane reached 1879 parts per billion (ppb) in 2020, more than two and a half times the preindustrial concentration of 722 ppb.[51] Moreover, the 2020 concentration was an increase of almost 13 ppb over 2019—the largest annual increase in methane concentrations of the period since the early 1990s, continuing a trend of rapid rise since a temporary pause ended in 2007.[52] Methane has a high radiative efficiency—almost 30 times that of carbon dioxide per ppb (and therefore, 80 times as much per unit mass).[53] In addition, methane contributes to climate change through chemical reactions in the atmosphere that produce tropospheric ozone and stratospheric water vapor. Human emissions of methane are responsible for about one third of the warming due to well-mixed GHGs, the second most important human warming agent after carbon dioxide.[54] Because of the substantial emissions of methane, and its radiative efficiency, methane mitigation is one of the best opportunities for reducing near term warming.

The tropospheric ozone produced by the reaction of methane in the atmosphere has harmful effects for human health and plant growth in addition to its climate effects.[55] In remote areas, methane is an important precursor to tropospheric ozone formation.[56] Approximately 50 percent of the global annual mean ozone increase since preindustrial times is believed to be due to anthropogenic methane.[57] Projections of future emissions also indicate that methane is likely to be a key contributor to ozone concentrations in the future.[58] Unlike NO_X and VOC, which affect ozone concentrations regionally and at hourly time scales, methane emissions affect ozone concentrations globally and on decadal time scales given methane's long atmospheric lifetime when compared to these other ozone precursors.[59] Reducing methane emissions, therefore, will contribute to efforts to reduce global background ozone concentrations that contribute to the incidence of ozone-related health effects.[60] The benefits of such reductions are global and occur in both urban and rural areas.

These scientific assessments and documented observed changes in the climate of the planet and of the U.S. present clear support regarding the current and future dangers of climate change and the importance of GHG mitigation.

2. VOC

Many VOC can be classified as HAP (*e.g.,* benzene),[61] which can lead to a variety of health concerns such as cancer and noncancer illnesses (*e.g.,* respiratory, neurological). Further, VOC are one of the key precursors in the formation of ozone. Tropospheric, or ground-level, ozone is formed through reactions of VOC and NO_X in the presence of sunlight. Ozone formation can be controlled to some extent through reductions in emissions of the ozone precursors VOC and NO_X. Recent observational and modeling studies have found that VOC emissions from oil and natural gas operations can impact ozone levels.[62 63 64 65] A significantly expanded body of scientific evidence shows that ozone can cause a number of harmful effects on health and the environment. Exposure to ozone can cause respiratory system effects such as difficulty breathing and airway inflammation. For people with lung diseases such as asthma and chronic obstructive pulmonary disease (COPD), these effects can lead to emergency room visits and hospital admissions. Studies have also found that ozone exposure is likely to cause premature death from lung or heart diseases. In addition, evidence indicates that long-term exposure to ozone is likely to result in harmful respiratory effects, including respiratory symptoms and the development of asthma. People most at risk from breathing air containing ozone include children; people with asthma and other respiratory diseases; older adults; and people who are active outdoors, especially outdoor workers. An estimated 25.9 million people have asthma in the U.S., including almost 7.1 million children. Asthma disproportionately affects children, families with lower incomes, and minorities, including Puerto Ricans, Native Americans/Alaska Natives, and African Americans.[66]

In the EPA's 2020 Integrated Science Assessment (ISA) for Ozone and Related Photochemical Oxidants,[67] the EPA estimates the incidence of air pollution effects for those health endpoints above where the ISA classified as either causal or likely-to-be-causal. In brief, the ISA for ozone found short-term (less than one month) exposures to ozone to be

[49] Ziska, L., A. Crimmins, A. Auclair, S. DeGrasse, J.F. Garofalo, A.S. Khan, I. Loladze, A.A. Pérez de León, A.Showler, J. Thurston, and I. Walls, 2016: Ch. 7: *Food Safety, Nutrition, and Distribution. The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment.* U.S. Global Change Research Program, Washington, DC, 189–216. *http://dx.doi.org/10.7930/J0ZP4417*

[50] WMO (World Meteorological Organization), *Scientific Assessment of Ozone Depletion: 2018, Global Ozone Research and Monitoring Project*—Report No. 58, 588 pp., Geneva, Switzerland, 2018.

[51] Blunden et al., 2020.

[52] NOAA, *https://gml.noaa.gov/webdata/ccgg/trends/ch4/ch4_annmean_gl.txt,* accessed August 19th, 2021.

[53] IPCC, 2021.

[54] IPCC, 2021.

[55] Nolte, C.G., P.D. Dolwick, N. Fann, L.W. Horowitz, V. Naik, R.W. Pinder, T.L. Spero, D.A. Winner, and L.H. Ziska, 2018: *Air Quality. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment,* Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 512–538. doi: 10.7930/NCA4. 2018. CH13

[56] U.S. EPA. 2013. ''*Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Final Report).*'' EPA–600–R–10–076F. National Center for Environmental Assessment—RTP Division. Available at *http://www.epa.gov/ncea/isa/.*

[57] Myhre, G., D. Shindell, F.-M. Bréon, W. Collins, J. Fuglestvedt, J. Huang, D. Koch, J.-F. Lamarque, D. Lee, B. Mendoza, T. Nakajima, A. Robock, G. Stephens, T. Takemura and H. Zhang, 2013: *Anthropogenic and Natural Radiative Forcing. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Pg. 680.

[58] *Ibid.*

[59] *Ibid.*

[60] USGCRP, 2018.

[61] Benzene Integrated Risk Information System (IRIS) Assessment: *https://cfpub.epa.gov/ncea/iris2/chemicalLanding.cfm?substance_nmbr=276.*

[62] Benedict, K. B., Zhou, Y., Sive, B. C., Prenni, A. J., Gebhart, K. A., Fischer, E. V., . . . & Collett Jr, J. L. 2019. Volatile organic compounds and ozone in Rocky Mountain National Park during FRAPPE. *Atmospheric Chemistry and Physics, 19*(1), 499–521.

[63] Lindaas, J., Farmer, D. K., Pollack, I. B., Abeleira, A., Flocke, F., & Fischer, E. V. 2019. Acyl peroxy nitrates link oil and natural gas emissions to high ozone abundances in the Colorado Front Range during summer 2015. *Journal of Geophysical Research: Atmospheres, 124*(4), 2336–2350.

[64] McDuffie, E. E., Edwards, P. M., Gilman, J. B., Lerner, B. M., Dubé, W. P., Trainer, M., . . . & Brown, S. S. 2016. Influence of oil and gas emissions on summertime ozone in the Colorado Northern Front Range. *Journal of Geophysical Research: Atmospheres, 121*(14), 8712–8729.

[65] Tzompa-Sosa, Z. A., & Fischer, E. V. 2021. Impacts of emissions of C2-C5 alkanes from the US oil and gas sector on ozone and other secondary species. *Journal of Geophysical Research: Atmospheres, 126*(1), e2019JD031935.

[66] National Health Interview Survey (NHIS) Data, 2011. *http://www.cdc.gov/asthma/nhis/2011/data.htm.*

[67] Integrated Science Assessment (ISA) for Ozone and Related Photochemical Oxidants (Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R–20/012, 2020.

causally related to respiratory effects, a ''likely to be causal'' relationship with metabolic effects and a ''suggestive of, but not sufficient to infer, a causal relationship'' for central nervous system effects, cardiovascular effects, and total mortality. The ISA reported that long-term exposures (one month or longer) to ozone are ''likely to be causal'' for respiratory effects including respiratory mortality, and a ''suggestive of, but not sufficient to infer, a causal relationship'' for cardiovascular effects, reproductive effects, central nervous system effects, metabolic effects, and total mortality. An example of quantified incidence of ozone health effects can be found in the Regulatory Impact Analysis for the Final Revised Cross-State Air Pollution Rule (CSAPR) Update.

Scientific evidence also shows that repeated exposure to ozone can reduce growth and have other harmful effects on sensitive plants and trees. These types of effects have the potential to impact ecosystems and the benefits they provide.

3. SO_2

Current scientific evidence links short-term exposures to SO_2, ranging from 5 minutes to 24 hours, with an array of adverse respiratory effects including bronchoconstriction and increased asthma symptoms. These effects are particularly important for asthmatics at elevated ventilation rates (*e.g.,* while exercising or playing).

Studies also show an association between short-term exposure and increased visits to emergency departments and hospital admissions for respiratory illnesses, particularly in at-risk populations including children, the elderly, and asthmatics.

SO_2 in the air can also damage the leaves of plants, decrease their ability to produce food—photosynthesis—and decrease their growth. In addition to directly affecting plants, SO_2, when deposited on land and in estuaries, lakes, and streams, can acidify sensitive ecosystems resulting in a range of harmful indirect effects on plants, soils, water quality, and fish and wildlife (*e.g.,* changes in biodiversity and loss of habitat, reduced tree growth, loss of fish species). Sulfur deposition to waterways also plays a causal role in the methylation of mercury.[68]

[68] U.S. EPA. *Integrated Science Assessment (ISA) for Oxides of Nitrogen and Sulfur Ecological Criteria* (2008 Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R–08/082F, 2008.

B. Oil and Natural Gas Industry and Its Emissions

This section generally describes the structure of the Oil and Natural Gas Industry, the interconnected production, processing, transmission and storage, and distribution segments that move product from well to market, and types of emissions sources in each segment and the industry's emissions.

1. Oil and Natural Gas Industry—Structure

The EPA characterizes the oil and natural gas industry's 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.[69] [70] The EPA regulates oil refineries as a separate source category; accordingly, as with the previous oil and gas NSPS rulemakings, 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.'' [71]

a. Production Segment

The oil and natural gas production segment includes the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, and separation or treatment of oil and/or natural gas (including condensate). Although many wells produce a combination of oil and natural gas, wells can generally be grouped into two categories, oil wells and natural gas wells. Oil wells comprise two types, oil wells that produce crude oil only and oil wells that produce both crude oil and natural gas (commonly referred to as ''associated'' gas). Production equipment and components located on the well pad may include, but are not limited to, wells and related casing heads; tubing heads; ''Christmas tree'' piping, pumps, compressors; heater treaters; separators; storage vessels; pneumatic devices; and dehydrators. Production operations include well drilling, completion, and recompletion processes, including all the portable non-self-propelled apparatuses associated with those operations.

Other sites that are part of the production segment include ''centralized tank batteries,'' stand-alone sites where oil, condensate, produced water, and natural gas from several wells may be separated, stored, or treated. The production segment also includes gathering pipelines, gathering and boosting compressor stations, and related components that collect and transport the oil, natural gas, and other materials and wastes from the wells to the refineries or natural gas processing plants.

Of these products, crude oil and natural gas undergo successive, separate processing. Crude oil is separated from water and other impurities and transported to a refinery via truck, railcar, or pipeline. As noted above, the EPA treats oil refineries as a separate source category, accordingly, for present purposes, the oil component of the production segment ends at the point of custody transfer at the refinery.[72]

The separated, unprocessed natural gas is commonly referred to as field gas and is composed of methane, natural gas liquids (NGL), and other impurities, such as water vapor, H_2S, CO_2, helium, and nitrogen. Ethane, propane, butane, isobutane, and pentane are all considered NGL and often are sold separately for a variety of different uses. Natural gas with high methane content is referred to as ''dry gas,'' while natural gas with significant amounts of ethane, propane, or butane is referred to as ''wet gas.'' Natural gas typically is sent to gas processing plants in order to separate NGLs for use as feedstock for petrochemical plants, burned for space heating and cooking, or blended into vehicle fuel.

b. Processing Segment

The natural gas processing segment consists of separating certain hydrocarbons (HC) and fluids from the natural gas to produce ''pipeline quality'' dry natural gas. The degree and

[69] The EPA previously described an overview of the sector in section 2.0 of the 2011 Background Technical Support Document to 40 CFR part 60, subpart OOOO, located at Docket ID Item No. EPA–HQ–OAR–2010–0505–0045, and section 2.0 of the 2016 Background Technical Support Document to 40 CFR part 60, subpart OOOOa, located at Docket ID Item No. EPA–HQ–OAR–2010–0505–7631.

[70] While generally oil and natural gas production includes both onshore and offshore operations, 40 CFR part 60, subpart OOOOa addresses onshore operations.

[71] For regulatory purposes, 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. The distribution segment is not part of the defined source category.

[72] See 40 CFR part 60, subparts J and Ja, and 40 CFR part 63, subparts CC and UUU.

location of processing is dependent on factors such as the type of natural gas (*e.g.,* wet or dry gas), market conditions, and company contract specifications. Typically, processing of natural gas begins in the field and continues as the gas is moved from the field through gathering and boosting compressor stations to natural gas processing plants, where the complete processing of natural gas takes place. Natural gas processing operations separate and recover NGL or other non-methane gases and liquids from field gas through one or more of the following processes: oil and condensate separation, water removal, separation of NGL, sulfur and CO_2 removal, fractionation of NGL, and other processes, such as the capture of CO_2 separated from natural gas streams for delivery outside the facility.

c. Transmission and Storage Segment

Once natural gas processing is complete, the resulting natural gas exits the natural gas process plant and enters the transmission and storage segment where it is transmitted to storage and/ or distribution to the end user.

Pipelines in the natural gas transmission and storage segment can be interstate pipelines, which carry natural gas across state boundaries, or intrastate pipelines, which transport the gas within a single state. Basic components of the two types of pipelines are the same, though interstate pipelines may be of a larger diameter and operated at a higher pressure. To ensure that the natural gas continues to flow through the pipeline, the natural gas must periodically be compressed, thereby increasing its pressure. Compressor stations perform this function and are usually placed at 40- to 100-mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

Another part of the transmission and storage segment are aboveground and underground natural gas storage facilities. Storage facilities hold natural gas for use during peak seasons. The main difference between underground and aboveground storage sites is that storage takes place in storage vessels constructed of non-earthen materials in aboveground storage. Underground storage of natural gas typically occurs in depleted natural gas or oil reservoirs and salt dome caverns. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, typically other processes occur, including compression, dehydration, and flow measurement.

d. Distribution Segment

The distribution segment provides the final step in delivering natural gas to customers.[73] The natural gas enters the distribution segment from delivery points located along interstate and intrastate transmission pipelines to business and household customers. The delivery point where the natural gas leaves the transmission and storage segment and enters the distribution segment is a local distribution company's custody transfer station, commonly referred to as the ''city-gate.'' Natural gas distribution systems consist of over 2 million miles of piping, including mains and service pipelines to the customers. If the distribution network is large, compressor stations may be necessary to maintain flow; however, these stations are typically smaller than transmission compressor stations. Distribution systems include metering stations and regulating stations, which allow distribution companies to monitor the natural gas as it flows through the system.

2. Oil and Natural Gas Industry—Emissions

The oil and natural gas industry sector is the largest source of industrial methane emissions in the U.S.[74] Natural gas is comprised primarily of methane; every natural gas leak or intentional release through venting or other industrial processes constitutes a release of methane. Methane is a potent greenhouse gas; over a 100-year timeframe, it is nearly 30 times more powerful at trapping climate warming heat than CO_2, and over a 20-year timeframe, it is 83 times more powerful.[75] 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. Additionally, the Crude Oil and Natural Gas sector emits, in varying concentrations and amounts, a wide range of other health-harming pollutants, including VOCs, SO_2, NO_X, H_2S, CS_2, and COS. The year 2016 modeling platform produced by U.S. EPA estimated about 3 million tons of VOC are emitted by oil and gas-related sources.[76]

Emissions of methane and these co-pollutants occur in every segment of the Crude Oil and Natural Gas source category. Many of the processes and equipment types that contribute to these emissions are found in every segment of the source category and are highly similar across segments. Emissions from the crude oil portion of the regulated source category result primarily from field production operations, such as venting of associated gas from oil wells, oil storage vessels, and production-related equipment such as gas dehydrators, pig traps, and pneumatic devices. Emissions from the natural gas portion of the industry can occur in all segments. As natural gas moves through the system, emissions primarily result from intentional venting through normal operations, routine maintenance, unintentional fugitive emissions, flaring, malfunctions, and system upsets. Venting can occur through equipment design or operational practices, such as the continuous and intermittent bleed of gas from pneumatic controllers (devices that control gas flows, levels, temperatures, and pressures in the equipment). In addition to vented emissions, emissions can occur from leaking equipment (also referred to as fugitive emissions) in all parts of the infrastructure, including major production and processing equipment (*e.g.,* separators or storage vessels) and individual components (*e.g.,* valves or connectors). Flares are commonly used throughout each segment in the Oil and Natural Gas Industry as a control device to provide pressure relief to prevent risk of explosions and to destroy methane, which has a high global warming potential, and convert it to CO_2 which has a lower global warming potential, and to also control other air pollutants such as VOC.

''Super-emitting'' events, sites, or equipment, where a small proportion of sources account for a large proportion of overall emissions, can occur throughout the Oil and Natural Gas Industry and have been observed to occur in the equipment types and activities covered by this proposed action. There are a number of definitions for the term ''super-emitter.'' A 2018 National Academies of Sciences, Engineering, and Medicine report[77] on methane discussed three categories of ''high-emitting'' sources:

[73] The distribution segment is not included in the definition of the Crude Oil and Natural Gas source category that is currently regulated under 40 CFR part 60, subpart OOOOa.

[74] H.R. Rep. No. 117–64, 4 (2021) (Report by the House Committee on Energy and Commerce concerning H.J. Res. 34, to disapprove the 2020 Policy Rule) (House Report).

[75] IPCC, 2021.

[76] *https://www.epa.gov/sites/default/files/2020-11/documents/2016v1_emismod_tsd_508.pdf.*

[77] *https://www.nap.edu/download/24987#.*

- Routine or ''chronic'' high-emitting sources, which regularly emit at higher rates relative to ''peers'' in a sample. Examples include large facilities, or large emissions at smaller facilities caused by poor design or operational practices.
- Episodic high-emitting sources, which are typically large in nature and are generally intentional releases from known maintenance events at a facility. Examples include gas well liquids unloading, well workovers and maintenance activities, and compressor station or pipeline blowdowns.
- Malfunctioning high-emitting sources, which can be either intermittent or prolonged in nature and result from malfunctions and poor work practices. Examples include malfunctioning intermittent pneumatic controllers and stuck open dump valves. Another example is well blowout events. For example, a 2018 well blowout in Ohio was estimated to have emitted over 60,000 tons of methane.[78]

Super-emitters have been observed at many different scales, from site-level to component-level, across many research studies.[79] Studies will often develop a study-specific definition such as a top percentile of emissions in a study population (*e.g.,* top 10 percent), emissions exceeding a certain threshold (*e.g.,* 26 kg/day), emissions over a certain detection threshold (*e.g.,* 1–3 g/s) or as facilities with the highest proportional emission rate.[80] For certain equipment types and activities, the EPA's GHG emission estimates include the full range of conditions, including ''super-emitters.'' For other situations, where data are available, emissions estimates for abnormal events are calculated separately and included in the Inventory of U.S. Greenhouse Gas Emissions and Sinks (''GHGI'') (*e.g.,* Aliso Canyon leak event).[81] Given the variability of practices and technologies across oil and gas systems and the occurrence of episodic events, it is possible that the EPA's estimates do not include all methane emissions from abnormal events. The EPA continues to work through its stakeholder process to review new data from the EPA's 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'') and research studies to assess how emissions estimates can be improved. Because lost gas, whether through fugitive emissions, unintentional gas carry through, or intentional releases, represents lost earning potential, the industry benefits from capturing and selling emissions of natural gas (and methane). Limiting super-emitters through actions included in this rule such as reducing fugitive emissions, using lower emitting equipment where feasible, and employing best management practices will not only reduce emissions but reduce the loss of revenue from this valuable commodity.

Below we provide estimated emissions of methane, VOC, and SO_2 from Oil and Natural Gas Industry operation sources.

Methane emissions in the U.S. and from the Oil and Natural Gas industry. Official U.S. estimates of national level GHG emissions and sinks are developed by the EPA for the GHGI in fulfillment of commitments under the United Nations Framework Convention on Climate Change. The GHGI, which includes recent trends, is organized by industrial sector. The oil and natural gas production, natural gas processing, and natural gas transmission and storage sectors emit 28 percent of U.S. anthropogenic methane. Table 7 below presents total U.S. anthropogenic methane emissions for the years 1990, 2010, and 2019.

In accordance with the practice of the EPA GHGI, the EPA GHGRP, and international reporting standards under the UN Framework Convention on Climate Change, the 2007 IPCC Fourth Assessment Report value of the methane 100-year GWP is used for weighting emissions in the following tables. The 100-year GWP value of 25 for methane indicates that one ton of methane has approximately as much climate impact over a 100-year period as 25 tons of carbon dioxide. The most recent IPCC AR6 assessment has estimated a slightly larger 100-year GWP of methane of almost 30 (specifically, either 27.2 or 29.8 depending on whether the value includes the carbon dioxide produced by the oxidation of methane in the atmosphere). As mentioned earlier, because methane has a shorter lifetime than carbon dioxide, the emissions of a ton of methane will have more impact earlier in the 100-year timespan and less impact later in the 100-year timespan relative to the emissions of a 100-year GWP-equivalent quantity of carbon dioxide: When using the AR6 20-year GWP of 81, which only looks at impacts over the next 20 years, the total US emissions of methane in 2019 would be equivalent to about 2140 MMT CO_2.

TABLE 7—U.S. METHANE EMISSIONS BY SECTOR

[Million metric tons carbon dioxide equivalent (MMT CO_2 EQ.)]

Sector	1990	2010	2019
Oil and Natural Gas Production, and Natural Gas Processing and Transmission and Storage	189	176	182
Landfills	177	124	114
Enteric Fermentation	165	172	179

[78] Pandey et al. (2019). Satellite observations reveal extreme methane leakage from a natural gas well blowout. PNAS December 26, 2019 116 (52) 26376–26381.

[79] See for example, Brandt, A., Heath, G., Cooley, D. (2016) *Methane leaks from natural gas systems follow extreme distributions.* Environ. Sci. Technol., DOI: 10.1021/acs.est.6b04303; Zavala-Araiza, D., Alvarez, R.A., Lyon, D.R., Allen, D.T., Marchese, A.J., Zimmerle, D.J., & Hamburg, S.P. (2017). *Super-emitters in natural gas infrastructure are caused by abnormal process conditions.* Nature communications, 8, 14012; Mitchell, A., et al. (2015), *Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results.* Environmental Science & Technology, 49(5), 3219–3227; Allen, D., et al. (2014), *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers.* Environmental Science & Technology.

[80] Caulton et al. (2019). *Importance of Super-emitter Natural Gas Well Pads in the Marcellus Shale.* Environ. Sci. Technol. 2019, 53, 4747–4754; Zavala-Araiza, D., Alvarez, R., Lyon, D, et al. (2016). *Super-emitters in natural gas infrastructure are caused by abnormal process conditions.* Nat Commun 8, 14012 (2017). *https://www.nature.com/articles/ncomms14012;* Lyon, et al. (2016). *Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites.* Environ. Sci. Technol. 2016, 50, 4877–4886. *https://pubs.acs.org/doi/10.1021/acs.est.6b00705;* and Zavala-Araiza D, et al. (2015). *Toward a functional definition of methane superemitters: Application to natural gas production sites.* 49 ENVTL. SCI. & TECH. 8167, 8168 (2015). *https://pubs.acs.org/doi/10.1021/acs.est.5b00133.*

[81] The EPA's emission estimates in the GHGI are developed with the best data available at the time of their development, including data from the Greenhouse Gas Reporting Program (GHGRP) in 40 CFR part 98, subpart W, and from recent research studies. GHGRP subpart W emissions data used in the GHGI are quantified by reporters using direct measurements, engineering calculations, or emission factors, as specified by the regulation. The EPA has a multi-step data verification process for GHGRP subpart W data, including automatic checks during data-entry, statistical analyses on completed reports, and staff review of the reported data. Based on the results of the verification process, the EPA follows up with facilities to resolve mistakes that may have occurred.

TABLE 7—U.S. METHANE EMISSIONS BY SECTOR—Continued

[Million metric tons carbon dioxide equivalent (MMT CO_2 EQ.)]

Sector	1990	2010	2019
Coal Mining	96	82	47
Manure Management	37	55	62
Other Oil and Gas Sources	46	17	15
Wastewater Treatment	20	19	18
Other Methane Sources [82]	46	47	42
Total Methane Emissions	777	692	660

Emissions from the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2019 (published April 14, 2021), calculated using GWP of 25. **Note:** Totals may not sum due to rounding.

Table 8 below presents total methane emissions from natural gas production through transmission and storage and petroleum production, for years 1990, 2010, and 2019, in MMT CO_2 Eq. (or million metric tons CO_2 Eq.) of methane.

TABLE 8—U.S. METHANE EMISSIONS FROM NATURAL GAS AND PETROLEUM SYSTEMS

[MMT CO_2 EQ.]

Sector	1990	2010	2019
Natural Gas Production	63	97	94
Natural Gas Processing	21	10	12
Natural Gas Transmission and Storage	57	30	37
Petroleum Production	48	39	38

Emissions from the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2019 (published April 14, 2021), calculated using GWP of 25. **Note:** Totals may not sum due to rounding.

Global GHG Emissions. For additional background information and context, we used 2018 World Resources Institute Climate Watch data to make comparisons between U.S. oil and natural gas production and natural gas processing and transmission and storage emissions and the emissions inventories of entire countries and regions.[83] The U.S. methane emissions from oil and natural gas production and natural gas processing and transmission and storage constitute 0.4 percent of total global emissions of all GHGs (48,601 MMT CO2 Eq.) from all sources.[84] Ranking U.S. emissions of methane from oil and natural gas production and natural gas processing and transmission and storage against total GHG emissions for entire countries (using 2018 Climate Watch data), shows that these emissions are comparatively large as they exceed the national-level emissions totals for all GHGs and all anthropogenic sources for Colombia, the Czech Republic, Chile, Belgium, and over 160 other countries. What that means is that the U.S. emits more of a single GHG—methane—from a single sector—the oil and gas sector—than the total combined GHGs emitted by 164 out of 194 total countries. Furthermore, U.S. emissions of methane from oil and natural gas production and natural gas processing and transmission and storage are greater than the sum of total emissions of 64 of the lowest-emitting countries and territories, using the 2018 Climate Watch data set.

As illustrated by the domestic and global GHGs comparison data summarized above, 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. Consideration of the global context is important. GHG emissions from U.S. Oil and Natural Gas production and natural gas processing and transmission and storage will become globally well-mixed in the atmosphere, and thus will have an effect on the U.S. regional climate, as well as the global climate as a whole for years and indeed many decades to come. 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.

The IPCC AR6 assessment determined that ''From a physical science perspective, limiting human-induced global warming to a specific level requires limiting cumulative CO_2 emissions, reaching at least net zero CO_2 emissions, along with strong reductions in other GHG emissions.'' The report also singled out the importance of ''strong and sustained CH_4 emission reductions'' in part due to the short lifetime of methane leading to the near-term cooling from reductions in methane emissions, which can offset the warming that will result due to reductions in emissions of cooling aerosols such as SO_2. Therefore, reducing methane emissions globally is an important facet in any strategy to limit warming. In the oil and gas sector,

[82] Other sources include rice cultivation, forest land, stationary combustion, abandoned oil and natural gas wells, abandoned coal mines, mobile combustion, composting, and several sources emitting less than 1 MMT CO_2 Eq. in 2019.

[83] The Climate Watch figures presented here come from the PIK PRIMAP-hist dataset included on Climate Watch. The PIK PRIMAP-hist dataset combines the United Nations Framework Convention on Climate Change (UNFCCC) reported data where available and fills gaps with other sources. It does not include land use change and forestry but covers all other sectors. *https://www.climatewatchdata.org/ghg-emissions?end_year=2018&source=PIK&start_year=1990.*

methane reductions are highly achievable and cost-effective using existing and well-known solutions and technologies that actually result in recovery of saleable product.

VOC and SO_2 emissions in the U.S. and from the oil and natural gas industry. Official U.S. estimates of national level VOC and SO_2 emissions are developed by the EPA for the National Emissions Inventory (NEI), for which States are required to submit information under 40 CFR part 51, subpart A. Data in the NEI may be organized by various data points, including sector, NAICS code, and Source Classification Code. Tables 9 and 10 below present total U.S. VOC and SO_2 emissions by sector, respectively, for the year 2017, in kilotons (kt) (or thousand metric tons). The oil and natural gas sector represents the top anthropogenic U.S. sector for VOC emissions after removing the biogenics and wildfire sectors in Table 9 (about 20% of the total VOC emitting by anthropogenic sources). About 2.5 percent of the total U.S. anthropogenic SO_2 comes from the oil and natural gas sector.

TABLE 9—U.S. VOC EMISSIONS BY SECTOR

[kt]

Sector	2017
Biogenics—Vegetation and Soil	25,823
Fires—Wildfires	4,578
Oil and Natural Gas Production, and Natural Gas Processing and Transmission	2,504
Fires—Prescribed Fires	2,042
Solvent—Consumer and Commercial Solvent Use	1,610
Mobile—On-Road non-Diesel Light Duty Vehicles	1,507
Mobile—Non-Road Equipment—Gasoline	1,009
Other VOC Sources [85]	4,045
Total VOC Emissions	43,118

Emissions from the 2017 NEI (released April 2020). **Note:** Totals may not sum due to rounding.

TABLE 10—U.S. SO_2 EMISSIONS BY SECTOR

[kt]

Sector	2017
Fuel Combustion—Electric Generation—Coal	1,319
Fuel Combustion—Industrial Boilers, Internal Combustion Engines—Coal	212
Mobile—Commercial Marine Vessels	183
Industrial Processes—Not Elsewhere Classified	138
Fires—Wildfires	135
Industrial Processes—Chemical Manufacturing	123
Oil and Natural Gas Production and Natural Gas Processing and Transmission	65
Other SO_2 Sources [86]	551
Total SO_2 Emissions	2,726

Emissions from the 2017 NEI (released April 2020). **Note:** Totals may not sum due to rounding.

Table 11 below presents total VOC and SO_2 emissions from oil and natural gas production through transmission and storage, for the year 2017, in kt. The contribution to the total anthropogenic VOC emissions budget from the oil and gas sector has been increasing in recent NEI cycles. In the 2017 NEI, the oil and gas sector makes up about 25 percent of the total VOC emissions from anthropogenic sources. The SO_2 emissions have been declining in just about every anthropogenic sector, but the oil and gas sector is an exception where SO_2 emissions have been slightly increasing or remaining steady in some cases in recent years.

TABLE 11—U.S. VOC AND SO_2 EMISSIONS FROM NATURAL GAS AND PETROLEUM SYSTEMS

[kt]

Sector	VOC	SO_2
Oil and Natural Gas Production	2,478	41
Natural Gas Processing	12	23
Natural Gas Transmission and Storage	14	1

Emissions from the 2017 NEI, (published April 2020), in kt (or thousand metric tons). **Note:** Totals may not sum due to rounding.

[85] Other sources include remaining sources emitting less than 1,000 kt VOC in 2017.

[86] Other sources include remaining sources emitting less than 100 kt SO_2 in 2017.

IV. Statutory Background and Regulatory History

A. Statutory Background of CAA Sections 111(b), 111(d) and General Implementing Regulations

The EPA's authority for this rule is CAA section 111, which governs the establishment of standards of performance for stationary sources. This section requires the EPA to list source categories to be regulated, establish standards of performance for air pollutants emitted by new sources in that source category, and establish EG for States to establish standards of performance for certain pollutants emitted by existing sources in that source category.

Specifically, CAA section 111(b)(1)(A) requires that a source category be included on the list for regulation if, ''in [the EPA Administrator's] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' This determination is commonly referred to as an ''endangerment finding'' and that phrase encompasses both of the ''causes or contributes significantly to'' component and the ''endanger public health or welfare'' component of the determination. Once a source category is listed, CAA section 111(b)(1)(B) requires that the EPA propose and then promulgate ''standards of performance'' for new sources in such source category. CAA section 111(a)(1) defines a ''standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' As long recognized by the D.C. Circuit, ''[b]ecause Congress did not assign the specific weight the Administrator should accord each of these factors, the Administrator is free to exercise his discretion in this area.'' *New York* v. *Reilly,* 969 F.2d 1147, 1150 (D.C. Cir. 1992). *See also Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999) (''*Lignite Energy Council*'') (''Because section 111 does not set forth the weight that be [sic] should assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them'').

In determining whether a given system of emission reduction qualifies as ''the best system of emission reduction . . . adequately demonstrated,'' or ''BSER,'' CAA section 111(a)(1) requires that the EPA take into account, among other factors, ''the cost of achieving such reduction.'' As described in the proposal [87] for the 2016 Rule (85 FR 35824, June 3, 2016), the U.S. Court of Appeals for the District of Columbia Circuit (the D.C. Circuit) has stated that in light of this provision, the EPA may not adopt a standard the cost of which would be ''exorbitant,'' [88] ''greater than the industry could bear and survive,'' [89] ''excessive,'' [90] or ''unreasonable.'' [91] These formulations appear to be synonymous, and for convenience, in this rulemaking, as in previous rulemakings, we will use reasonableness as the standard, so that a control technology may be considered the ''best system of emission reduction . . . adequately demonstrated'' if its costs are reasonable, but cannot be considered the BSER if its costs are unreasonable. See 80 FR 64662, 64720–21 (October 23, 2015).

CAA section 111(a) does not provide specific direction regarding what metric or metrics to use in considering costs, affording the EPA considerable discretion in choosing a means of cost consideration.[92] In this rulemaking, we evaluated whether a control cost is reasonable under a number of approaches that we find appropriate for assessing the types of controls at issue. For example, in evaluating controls for reducing VOC and methane emissions from new sources, we considered a control's cost effectiveness under both a ''single pollutant cost-effectiveness'' approach and a ''multipollutant cost-effectiveness'' approach, in order to appropriately take into account that the systems of emission reduction considered in this rule typically achieve reductions in multiple pollutants at once and secure a multiplicity of climate and public health benefits.[93] We also evaluated costs at a sector level by assessing the projected new capital expenditures required under the proposal (compared to overall new capital expenditures by the sector) and the projected compliance costs (compared to overall annual revenue for the sector) if the rule were to require such controls. For a detailed discussion of these cost approaches, please see section IX of the proposal preamble.

As defined in CAA section 111(a), the ''standard of performance'' that the EPA develops, based on the BSER, is expressed as a performance level (typically, a rate-based standard). CAA section 111(b)(5) precludes the EPA from prescribing a particular technological system that must be used to comply with a standard of performance. Rather, sources can select any measure or combination of measures that will achieve the standard.

CAA section 111(h)(1) authorizes the Administrator to promulgate ''a design, equipment, work practice, or operational standard, or combination thereof'' if in his or her judgment, ''it is not feasible to prescribe or enforce a standard of performance.'' CAA section 111(h)(2) provides the circumstances under which prescribing or enforcing a standard of performance is ''not feasible,'' such as, when the pollutant cannot be emitted through a conveyance designed to emit or capture the pollutant, or when there is no practicable measurement methodology for the particular class of sources.[94] CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years review and, if appropriate, revise'' performance standards unless the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard.

As mentioned above, once the EPA lists a source category under CAA section 111(b)(1)(A), CAA section 111(b)(1)(B) provides the EPA discretion to determine the pollutants and sources to be regulated. In addition, concurrent with the 8-year review (and though not a mandatory part of the 8-year review), the EPA may examine whether to add standards for pollutants or emission

[87] 80 FR 56593, 56616 (September 18, 2015).

[88] *Lignite Energy Council,* 198 F.3d at 933.

[89] *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975).

[90] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981).

[91] *Id.*

[92] See, *e.g., Husqvarna AB* v. *EPA,* 254 F.3d 195, 200 (D.C. Cir. 2001) (where CAA section 213 does not mandate a specific method of cost analysis, the EPA may make a reasoned choice as to how to analyze costs).

[93] We believe that both the single and multipollutant approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. The EPA has considered similar approaches in the past when considering multiple pollutants that are controlled by a given control option. See *e.g.,* 80 FR 56616–56617; 73 FR 64079–64083 and EPA Document ID Nos. EPA–HQ–OAR–2004–0022–0622, EPA–HQ–OAR–2004–0022–0447, EPA–HQ–OAR–2004–0022–0448.

[94] 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.

sources not currently regulated for that source category.

Once the EPA establishes NSPS in a particular source category, the EPA is required in certain circumstances to issue EG to reduce emissions from existing sources in that same source category. Specifically, CAA section 111(d) requires that the EPA prescribe 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. The EPA addresses this CAA requirement both through its promulgation of general implementing regulations for section 111(d) as well as specific EG. The EPA first published general implementing regulations in 1975, 40 FR 53340 (November 17, 1975) (codified at 40 CFR part 60, subpart B), and has revised its section 111(d) implementing regulations several times, most recently on July 8, 2019, 84 FR 32520 (codified at 40 CFR part 60, subpart Ba).[95] In accordance with CAA section 111(d), States are required to submit plans pursuant to these regulations to establish standards of performance for existing sources for any air pollutant: (1) The emission of which is subject to a Federal NSPS; and (2) which is neither a pollutant regulated under CAA section 108(a) (*i.e.,* criteria pollutants such as ground-level ozone and particulate matter, and their precursors, like VOC) [96] or a HAP regulated under CAA section 112. See also definition of ''designated pollutant'' in 40 CFR 60.21a(a). The EPA's general implementing regulations use the term ''designated facility'' to identify those existing sources that may be subject to regulation under this provision of CAA section 111(d). See 40 CFR 60.21a(b).

While States are authorized to establish standards of performance for designated facilities, there is a fundamental obligation under CAA section 111(d) that such standards of performance reflect the degree of emission limitation achievable through the application of the BSER, as determined by the Administrator. This obligation derives from the definition of ''standard of performance'' under CAA section 111(a)(1), which makes no distinction between new-source and existing-source standards. The EPA identifies the degree of emission limitation achievable through application of the BSER as part of its EG. See 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 source, to take into account the source's remaining useful life and other factors.

After the EPA issues final EG per the requirements under CAA section 111(d) and 40 CFR part 60, subpart Ba, States are required to submit plans that establish standards of performance for the designated facilities as defined in the EPA's guidelines and that contain other measures to implement and enforce those standards. The EPA's final EG issued under CAA section 111(d) do not impose binding requirements directly on sources, but instead provide requirements for States in developing their plans and criteria for assisting the EPA when judging the adequacy of such plans. Under CAA section 111(d), and the EPA's implementing regulations, a State must submit its plan to the EPA for approval, the EPA will evaluate the plan for completeness in accordance with enumerated criteria, and then will act on that plan via a rulemaking process to either approve or disapprove the plan in whole or in part. If a State does not submit a plan, or if the EPA does not approve a State's plan because it is not ''satisfactory,'' then the EPA must establish a Federal plan for that State.[97] If EPA approves a State's plan, the provisions in the state plan become federally enforceable against the designated facility responsible for compliance in the same manner as the provisions of an approved State implementation plan under CAA section 110. If no designated facility is located within a State, the State must submit to the EPA a letter certifying to that effect in lieu of submitting a State plan. See 40 CFR 60.23a(b).

Designated facilities located in Indian country would not be addressed by 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 [98] 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.[99] 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.[100]

B. What is the regulatory history and litigation background of NSPS and EG for the oil and natural gas industry?

1. 1979 Listing of Source Category

Subsequent to the enactment of the CAA of 1970, the EPA took action to develop standards of performance for new stationary sources as directed by Congress in CAA section 111. By 1977, the EPA had promulgated NSPS for a total of 27 source categories, while NSPS for an additional 25 source categories were then under development.[101] However, in amending the CAA that year, Congress expressed dissatisfaction that the EPA's pace was too slow. Accordingly, the 1977 CAA Amendments included a new subsection (f) in section 111, which specified a schedule for the EPA to list additional source categories under CAA section 111(b)(1)(A) and prioritize them for regulation under CAA section 111(b)(1)(B).

In 1979, as required by CAA section 111(f), the EPA published a list of source categories, which included ''*Crude Oil and Natural Gas Production,*'' for which the EPA would promulgate standards of performance under CAA section 111(b). See *Priority List and Additions to the List of Categories of Stationary Sources,* 44 FR 49222 (August 21, 1979) (''1979 Priority List''). That list included, in the order of priority for promulgating standards, source categories that the EPA Administrator had determined, pursuant to CAA section 111(b)(1)(A), contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. See 44 FR 49223 (August 21, 1979); see also 49 FR 2636–37 (January 20, 1984).

[95] Subpart Ba provides for the applicability of its provisions upon final publication of an EG if such EG is published after July 8, 2019. § 60.20a(a). The EPA acknowledges that the D.C. Circuit has vacated certain timing provisions within subpart Ba. *Am. Lung Assoc.* v. *EPA,* 985 F.3d 914 (D.C. Cir. 2021), *petition for cert. pending,* No. 20–1778 (filed June 23, 2001) (*Am. Lung Assoc.*). However, the court did not vacate the applicability provision, therefore subpart Ba applies to any EG finalized from this proposal. The Agency plans to undertake rulemaking to address the provisions vacated under the court's decision in the near future.

[96] VOC are not listed as CAA section 108(a) pollutants, but they are regulated precursors to photochemical oxidants (*e.g.,* ozone) and particulate matter (PM), both of which are listed CAA section 108(a) pollutants, and VOC therefore fall within the CAA 108(a) exclusion. Accordingly, promulgation of NSPS for VOC does not trigger the application of CAA section 111(d).

[97] CAA section 111(d)(2)(A).

[98] The EPA is aware of many oil and natural gas operations located in Indian Country.

[99] See 40 CFR part 49, subpart A.

[100] CAA section 111(d)(2)(A).

[101] See 44 FR 49222 (August 21, 1979).

2. 1985 NSPS for VOC and SO_2 Emissions From Natural Gas Processing Units

On June 24, 1985 (50 FR 26122), the EPA promulgated NSPS for the Crude Oil and Natural Gas source category that addressed VOC emissions from equipment leaks at onshore natural gas processing plants (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), the EPA promulgated additional NSPS for the source category to regulate SO_2 emissions from onshore natural gas processing plants (40 CFR part 60, subpart LLL).

3. 2012 NSPS OOOO Rule and Related Amendments

In 2012, pursuant to its duty under CAA section 111(b)(1)(B) to review and, if appropriate, revise the 1985 NSPS, the EPA published the final rule, ''Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution,'' 77 FR 49490 (August 16, 2012) (40 CFR part 60, subpart OOOO) (''2012 NSPS OOOO''). The 2012 rule updated the SO_2 standards for sweetening units and the VOC standards for equipment leaks at onshore natural gas processing plants. In addition, it established VOC standards for several oil and natural gas-related operations emission sources not covered by 40 CFR part 60, subparts KKK and LLL, including natural gas well completions, centrifugal and reciprocating compressors, certain natural gas operated pneumatic controllers in the production and processing segments of the industry, and storage vessels in the production, processing, and transmission and storage segments.

In 2013, 2014, and 2015 the EPA amended the 2012 NSPS OOOO rule in order to address implementation of the standards. ''Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards,'' 78 FR 58416 (September 23, 2013) (''2013 NSPS OOOO'') (concerning storage vessel implementation); ''Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards,'' 79 FR 79018 (December 31, 2014) (''2014 NSPS OOOO'') (concerning well completion); ''Oil and Natural Gas Sector: Definitions of Low Pressure Gas Well and Storage Vessel,'' 80 FR 48262 (August 12, 2015) (''2015 NSPS OOOO'') (concerning low pressure gas wells and storage vessels).

The EPA received petitions for both judicial review and administrative reconsiderations for the 2012, 2013, and 2014 NSPS OOOO rules. The EPA denied reconsideration for some issues, see ''Reconsideration of the Oil and Natural Gas Sector: New Source Performance Standards; Final Action,'' 81 FR 52778 (August 10, 2016), and, as noted below, granted reconsideration for other issues. As explained below, all litigation related to NSPS OOOO is currently in abeyance.

4. 2016 NSPS OOOOa Rule and Related Amendments

Regulatory action. On June 3, 2016, the EPA published a final rule titled ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule,'' at 81 FR 35824 (40 CFR part 60, subpart OOOOa) (''2016 Rule'' or ''2016 NSPS OOOOa'').[102] [103] The 2016 NSPS OOOOa rule established NSPS for sources of GHGs and VOC emissions for certain equipment, processes, and operations across the Oil and Natural Gas Industry, including in the transmission and storage segment. 81 FR at 35832. The EPA explained that the 1979 listing identified the source category broadly enough to include that segment and, in the alternative, if the listing had limited the source category to the production and processing segments, the EPA affirmatively expanded the source category to include the transmission and storage segment on grounds that operations in those segments are a sequence of functions that are interrelated and necessary for getting the recovered gas ready for distribution. 81 FR at 35832. In addition, because this rule was the first time that the EPA had promulgated NSPS for GHG emissions from the Crude Oil and Natural Gas source category, the EPA predicated those NSPS on a determination that it had a rational basis to regulate GHG emissions from the source category. 81 FR at 35843. In response to comments, the EPA explained that it was not required to make an additional pollutant-specific finding that GHG emissions from the source category contribute significantly to dangerous air pollution, but in the alternative, the EPA did make such a finding, relying on the same information that it relied on when determining that it had a rational basis to promulgate a GHGs NSPS. 81 FR at 35843.

Specifically, the 2016 NSPS OOOOa addresses the following emission sources:

- Sources that were unregulated under the 2012 NSPS OOOO (hydraulically fractured oil well completions, pneumatic pumps, and fugitive emissions from well sites and compressor stations);
- Sources that were regulated under the 2012 NSPS OOOO for VOC emissions, but not for GHG emissions (hydraulically fractured gas well completions and equipment leaks at natural gas processing plants); and
- Certain equipment that is used across the source category, of which the 2012 NSPS OOOO regulated emissions of VOC from only a subset (pneumatic controllers, centrifugal compressors, and reciprocating compressors, with the exception of those compressors located at well sites).

On March 12, 2018 (83 FR 10628), the EPA finalized amendments to certain aspects of the 2016 NSPS OOOOa requirements for the collection of fugitive emission components at well sites and compressor stations, specifically (1) the requirement that components on a delay of repair must conduct repairs during unscheduled or emergency vent blowdowns, and (2) the monitoring survey requirements for well sites located on the Alaska North Slope.

Petitions for judicial review and to reconsider. Following promulgation of the 2016 NSPS OOOOa rule, several states and industry associations challenged the rule in the D.C. Circuit. The Administrator also received five petitions for reconsideration of several provisions of the final rule. Copies of the petitions are posted in Docket ID No. EPA–HQ–OAR–2010–0505.[104] As noted below, the EPA granted reconsideration as to several issues raised with respect to the 2016 NSPS OOOOa rule and finalized certain modifications discussed in the next section. As explained below, all litigation challenging the 2016 NSPS OOOOa rule is currently stayed.

5. 2020 Policy and Technical Rules

Regulatory action. In September 2020, the EPA published two final rules to amend 2012 NSPS OOOO and 2016 NSPS OOOOa. The first is titled, ''Oil

[102] The June 3, 2016, rulemaking also included certain final amendments to 40 CFR part 60, subpart OOOO, to address issues on which the EPA had granted reconsideration.

[103] The EPA review which resulted in the 2016 NSPS OOOOa rule was instigated by a series of directives from then-President Obama targeted at reducing GHGs, including methane: The President's *Climate Action Plan* (June 2013); the President's *Climate Action Plan: Strategy to Reduce Methane Emissions* (''Methane Strategy'') (March 2014); and the President's goal to address, propose and set standards for methane and ozone-forming emissions from new and modified sources in the sector (January 2015, *https://obamawhitehouse.archives.gov/the-press-office/2015/01/14/fact-sheet-Administration-takes-steps-forward-climate-action-plan-anno-1*).

[104] See Docket ID Item Nos.: EPA–HQ–OAR–2010–0505–7682, EPA–HQ–OAR–2010–0505–7683, EPA–HQ–OAR–2010–0505–7684, EPA–HQ–OAR–2010–0505–7685, EPA–HQ–OAR–2010–0505–7686.

and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review.'' 85 FR 57018 (September 14, 2020). Commonly referred to as the 2020 Policy Rule, it first rescinded the regulations applicable to the transmission and storage segment on the basis that the 1979 listing limited the source category to the production and processing segments and that the transmission and storage segment is not ''sufficiently related'' to the production and processing segments, and therefore cannot be part of the same source category. 85 FR at 57027, 57029. In addition, the 2020 Policy Rule rescinded methane requirements for the industry's production and processing segments on two separate bases. The first was that such standards are redundant to VOC standards for these segments. 85 FR at 57030. The second was that the rule interpreted section 111 to require, or at least authorize the Administrator to require, a pollutant-specific ''significant contribution finding'' (SCF) as a prerequisite to a NSPS for a pollutant, and to require that such finding be supported by some identified standard or established set of criteria for determining which contributions are ''significant.'' 85 FR at 57034. The rule went on to conclude that the alternative significant-contribution finding that the EPA made in the 2016 Rule for GHG emissions was flawed because it accounted for emissions from the transmission and storage segment and because it was not supported by criteria or a threshold. 85 FR at 57038.[105]

Published on September 15, 2020, the second of the two rules is titled, ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration.'' Commonly referred to as the 2020 Technical Rule, this second rule made further amendments to the 2016 NSPS OOOOa following the 2020 Policy Rule to eliminate or reduce certain monitoring obligations and to address a range of issues in response to administrative petitions for reconsideration and other technical and implementation issues brought to the EPA's attention since the 2016 NSPS OOOOa rulemaking. Specifically, the 2020 Technical Rule exempted low-production well sites from fugitives monitoring (previously required semiannually), required semiannual monitoring at gathering and boosting compressor stations (previously quarterly), streamlined recordkeeping and reporting requirements, allowed compliance with certain equivalent State requirements as an alternative to NSPS fugitive requirements, streamlined the application process to request the use of new technologies to monitor for fugitive emissions, addressed storage tank batteries for applicability determination purposes and finalized several technical corrections. Because the 2020 Technical Rule was issued the day after the EPA's rescission of methane regulations in the 2020 Policy Rule, the amendments made in the 2020 Technical Rule applied only to the requirements to regulate VOC emissions from this source category. The 2020 Policy Rule amended 40 CFR part 60, subparts OOOO and OOOOa, as finalized in 2016. The 2020 Technical Rule amended the 40 CFR part 60, subpart OOOOa, as amended by the 2020 Policy Rule.

Petitions to reconsider. The EPA received three petitions for reconsideration of the 2020 rulemakings. Two of the petitions sought reconsideration of the 2020 Policy Rule. As discussed below, on June 30, 2021, the President signed into law S.J. Res. 14, a joint resolution under the CRA disapproving the 2020 Policy Rule, and as a result, the petitions for reconsideration on the 2020 Policy Rule are now moot. All three petitions sought reconsideration of certain elements of the 2020 Technical Rule.

Litigation. Several States and non-governmental organizations challenged the 2020 Policy Rule as well as the 2020 Technical Rule. All petitions for review regarding the 2020 Policy Rule were consolidated into one case in the D.C. Circuit. *State of California, et al.* v. *EPA,* No. 20–1357. On August 25, 2021, after the enactment of the joint resolution of Congress disapproving the 2020 Policy Rule (explained in section VIII below), the court granted petitioners motion to voluntarily dismiss their cases. *Id.* ECF Dkt #1911437. All petitions for review regarding the 2020 Technical Rule were consolidated into a different case in the D.C. Circuit. *Environmental Defense Fund, et al.* v. *EPA,* No. 20–1360 (D.C. Cir.). On February 19, 2021, the court issued an order granting a motion by the EPA to hold in abeyance the consolidated litigation over the 2020 Technical Rule pending EPA's rulemaking actions in response to E.O. 13990 and pending the conclusion of EPA's potential reconsideration of the 2020 Technical Rule. *Id.* ECF Dkt #1886335.

As mentioned above, the EPA received petitions for judicial review regarding the 2012, 2013, and 2014 NSPS OOOO rules as well as the 2016 NSPS OOOOa rule. The challenges to the 2012 NSPS OOOO rule (as amended by the 2013 NSPS OOOO and 2014 NSPS OOOO rules) were consolidated. *American Petroleum Institute* v. *EPA,* No. 13–1108 (D.C. Cir.). The majority of those cases were further consolidated with the consolidated challenges to the 2016 NSPS OOOOa rule. *West Virginia* v. *EPA,* No. 16–1264 (D.C. Cir.), see specifically ECF Dkt #1654072. As such, *West Virginia* v. *EPA* includes challenges to the 2012 NSPS OOOO rule (as amended by the 2013 NSPS OOOO and 2014 NSPS OOOO rules) as well as challenges to the 2016 NSPS OOOOa rule.[106] On December 10, 2020, the court granted a joint motion of the parties in *West Virginia* v. *EPA* to hold that case in abeyance until after the mandate has issued in the case regarding challenges to the 2020 Technical Rule. *West Virginia* v. *EPA,* ECF Dkt #1875192.

C. Congressional Review Act (CRA) Joint Resolution of Disapproval

On June 30, 2021, the President signed into law a joint resolution of Congress, S.J. Res. 14, adopted under the CRA,[107] disapproving the 2020 Policy Rule.[108] By the terms of the CRA, the signing into law of the CRA joint resolution of disapproval means that the 2020 Policy Rule is ''treated as though [it] had never taken effect.'' 5 U.S.C. 801(f). As a result, the VOC and methane standards for the transmission and storage segment, as well as the methane standards for the production and processing segments—all of which had been rescinded in the 2020 Policy Rule—remain in effect. In addition, the EPA's authority and obligation to require the States to regulate existing sources of methane in the Crude Oil and

[105] Following the promulgation of the 2020 Policy Rule, the EPA promulgated a final rule that identified a standard or criteria for determining which contributions are ''significant,'' which the D.C. Circuit vacated. ''Pollutant-Specific Significant Contribution Finding for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, and Process for Determining Significance of Other New Source Performance Standards Source Categories.'' 86 FR 2542 (Jan. 13, 2021), vacated by *California* v. *EPA,* No. 21–1035 (D.C. Cir.) (Order, April 5, 2021, Doc. #1893155).

[106] When the EPA issued the 2016 NSPS OOOOa rule, a challenge to the 2012 NSPS OOOO rule for failing to regulate methane was severed and assigned to a separate case, *NRDC* v. *EPA,* No. 16–1425 (D.C. Cir.), pending judicial review of the 2016 NSPS OOOOa in *American Petroleum Institute* v. *EPA,* No. 13–1108 (D.C. Cir.).

[107] The Congressional Review Act was adopted in Subtitle E of the Small Business Regulatory Enforcement Fairness Act of 1996.

[108] ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review,'' 85 FR 57018 (Sept. 14, 2020) (''2020 Policy Rule'').

Natural Gas source category under section 111(d) of the CAA also remains in effect.

The CRA resolution did not address the 2020 Technical Rule; therefore, those amendments remain in effect with respect to the VOC standards for the production and processing segments in effect at the time of its enactment. As part of this rulemaking, in sections VIII and X the EPA discusses the impact of the CRA resolution, and identifies and proposes appropriate changes to reinstate the regulatory text that had been rescinded by the 2020 Policy Rule and to resolve any discrepancies in the regulatory text between the 2016 NSPS OOOOa Rule and 2020 Technical Rule.

V. Related Emissions Reduction Efforts

This section summarizes related State actions and other Federal actions regulating oil and natural gas emissions sources and summarizes industry and voluntary efforts to reduce climate change. The proposed NSPS OOOOb and EG OOOOc include specific measures that build on the experience and knowledge the Agency and industry have gained through voluntary programs, as well as the leadership of the States in pioneering new regulatory programs. The proposed NSPS OOOOb and EG OOOOc consists of reasonable, proven, cost-effective technologies and practices that reflect the evolutionary nature of the Oil and Natural Gas Industry and proactive regulatory and voluntary efforts. The EPA intends that the requirements proposed in this document will spur all industry stakeholders in all parts of the country to apply these readily available and cost-effective measures.

A. Related State Actions and Other Federal Actions Regulating Oil and Natural Gas Sources

The EPA recognizes that several States and other Federal agencies currently regulate the Oil and Natural Gas Industry. The EPA also recognizes that these State and other Federal agency regulatory programs have matured since the EPA began implementing its 2012 NSPS and subsequent 2016 NSPS. The EPA further acknowledges the technical innovations that the Oil and Natural Gas Industry has made during the past decade; this industry is fast-paced and constantly changing based on the latest technology. The EPA commends these efforts and recognizes States for their innovative standards, alternative compliance options, and implementation strategies. The EPA recognizes that any one effort will not be enough to address the increasingly dangerous impacts of climate change on public health and welfare and believes that consistent Federal regulation of the Crude Oil and Natural Gas source category plays an important role. To have a meaningful impact on climate change and its impact to human health and the environment, a multifaceted approach needs to be taken to ensure methane reductions will be realized. The EPA also recognizes that States and other Federal agencies regulate in accordance with their own authorities and within their own respective jurisdictions, and collectively do not fully address the range of sources and emission reduction measures contained in this proposal. Direct Federal regulation of methane from new sources combined with the approved State plans that are consistent with the EPA's EG for existing sources will bring national consistency to level the regulatory playing field, help promote technological innovation, and reduce both climate- and other health-harming pollution from a large number of sources that are either currently unregulated or where additional cost-effective reductions can be obtained. The EPA is committed to working within its authority to provide opportunities to align its programs with other existing State and Federal programs to reduce unnecessary regulatory redundancy where appropriate.

Among assessing various studies and emissions data, the EPA reviewed many current and proposed State regulatory programs to identify potential regulatory options that could be considered for BSER.[109] For example, the EPA reviewed California, Colorado, and Canadian regulations, as well as a pending proposed rule in New Mexico, that require non-emitting pneumatic devices at certain facilities and in certain circumstances. The EPA also examined California, Colorado, New Mexico (proposed), Pennsylvania, Wyoming, and the Bureau of Land Management (BLM) standards for liquids unloading events. Some of these States have led the way in regulating emissions sources that were not yet subject to requirements under the NSPS OOOOa. For example, Colorado requires the use of best management practices to minimize hydrocarbon emissions and the need for well venting associated with downhole well maintenance and liquids unloading, unless venting is necessary for safety. Other States, such as New Mexico, are evaluating similar requirements. Other States have requirements for emission sources currently regulated under NSPS OOOOa that are more stringent. For example, California and Colorado require continuous bleed natural gas-driven pneumatic controllers be non-emitting, with specified exceptions. We recognize that, in some cases, the EPA's proposed NSPS and/or EG may be more stringent than existing programs and, in other cases, may be less stringent than existing programs. After careful review and consideration of State regulatory programs in place and proposed State regulations, we are proposing NSPS and EG that, when implemented, will reduce emissions of harmful air pollutants, promote gas capture and beneficial use, and provide opportunity for flexibility and expanded transparency in order to yield a consistent and accountable national program that provides a clear path for States and other Federal agencies to further partner to ensure their programs work in conjunction with each other.

As an example of how the EPA strives to work with sources in States that have overlapping regulations for the Oil and Natural Gas Industry, the 2020 Technical Rule included approval of certain State programs as alternatives to certain requirements in the Federal NSPS. Subject to certain caveats, the EPA deemed certain fugitive emissions standards for well sites and compressor stations located in specific States equivalent to the NSPS in an effort to reduce any regulatory burden imposed by duplicative State and Federal regulations. See 40 CFR 60.5399a. The EPA worked extensively with States and reviewed many details of many State programs in this effort. Further, the 2020 Technical Rule amended 40 CFR part 60, subpart OOOOa, to incorporate a process that allows other States not already listed in 40 CFR 60.5399a to request approval of their fugitive monitoring program as an alternative to the NSPS. The EPA is proposing to include a similar request and approval process in NSPS OOOOb. Further, the EPA plans to work closely with States as they develop their State plans pursuant to the EG to look for opportunities to reduce unnecessary administrative burden imposed by redundant and duplicative regulatory requirements and help States that want to establish more stringent standards.

In addition to States, certain Federal agencies also regulate aspects of the oil and natural gas industry pursuant to their own authorities and have other established programs affecting the industry. The EPA believes that Federal regulatory actions and efforts will provide other environmental co-

[109] The NSPS OOOOb and EG TSD provides a high-level summary of the state programs that the agency assessed for purposes of this proposal.

benefits, but the EPA recognizes itself to be the Federal agency that has primary responsibility to protect human health and the environment and has been given the unique responsibility and authority by Congress to address the suite of harmful air pollutants associated with this source category. The EPA further believes that to have a meaningful impact to address the dangers of climate change, it is going to require an ''all hands-on deck'' effort across all States and all Federal agencies. The EPA has maintained an ongoing dialogue with its Federal partners during the development of this proposed rule to minimize any potential regulatory conflicts and to minimize confusion and regulatory burden on the part of owners and operators. The below description summarizes other agencies' regulations and other established Federal programs.

The U.S. Department of the Interior (DOI) regulates the extraction of oil and gas from Federal lands. Bureaus within the DOI include BLM and the Bureau of Ocean Energy Management (BOEM). The BLM manages the Federal Government's onshore subsurface mineral estate—about 700 million acres (30 percent of the U.S.)—for the benefit of the American public. The BLM maintains an oil and gas leasing program pursuant to the Mineral Leasing Act, the Mineral Leasing Act for Acquired Lands, the Federal Land Management and Policy Act, and the Federal Oil and Gas Royalty Management Act. Pursuant to a delegation of Secretarial authority, the BLM also oversees oil and gas operations on many Indian/Tribal leases. The BLM's oil and gas operating regulations are found in 43 CFR part 3160. An oil and gas operator's general environmental and safety obligations are found at 43 CFR 3162.5. The BLM does not directly regulate emissions for the purposes of air quality. However, BLM does regulate venting and flaring of natural gas for the purposes of preventing waste. The governing Resource Management Plan may require lessees to follow State and the EPA emissions regulations. An operator may be required to control/mitigate emissions as a condition of approval (COA) on a drilling permit. The need for such a COA is determined by the environmental review process. The BLM's rules governing the venting and flaring of gas are contained in NTL–4A, which was issued in 1980. Under NTL–4A, limitations on royalty-free venting and flaring constitute the primary mechanism for addressing the surface waste of gas. In 2016, the BLM replaced NTL–4A with a new rule governing venting and flaring (''Waste Prevention Rule''). In addition to restricting royalty-free flaring, the rule set emissions standards for tanks and pneumatic equipment and established LDAR requirements. In 2020, a U.S. District Court of Wyoming largely vacated that rule, thereby reinstating NTL–4A. More detailed information can be found at the BLM's website: *https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/operations-and-production/methane-and-waste-prevention-rule.*

The BOEM manages the development of U.S. Outer Continental Shelf (offshore) energy and mineral resources. BOEM has air quality jurisdiction in the Gulf of Mexico [110] and the North Slope Borough of Alaska.[111] BOEM also has air jurisdiction in Federal waters on the Outer Continental Shelf 3–9 miles offshore (depending on State) and beyond. The Outer Continental Shelf Lands Act (OCSLA) section 5(a)(8) states, ''The Secretary of the Interior is authorized to prescribe regulations 'for compliance with the national ambient air quality standards pursuant to the CAA . . . to the extent that activities authorized under [the Outer Continental Shelf Lands Act] significantly affect the air quality of any State.' '' The EPA and States have the air jurisdiction onshore and in State waters, and the EPA has air jurisdiction offshore in certain areas. More detailed information can be found at BOEM's website: *https://www.boem.gov/.*

The U.S. Department of Transportation (DOT) manages the U.S. transportation system. Within DOT, the Pipeline and Hazardous Materials Safety Administration (PHMSA) is responsible for regulating and ensuring the safe and secure transport of energy and other hazardous materials to industry and consumers by all modes of transportation, including pipelines. While PHMSA regulatory requirements for gas pipeline facilities have focused on human safety, which has attendant environmental co-benefits, the ''Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020'' (Pub. L. 116–260, Division R; ''PIPES Act of 2020''), which was signed into law on December 27, 2020, revised PHMSA organic statutes to emphasize the centrality of environmental safety and protection of the environment in PHMSA decision making. For example, the PHMSA's Office of Pipeline Safety ensures safety in the design, construction, operation, maintenance, and incident response of the U.S.' approximately 2.6 million miles of natural gas and hazardous liquid transportation pipelines. When pipelines are maintained, the likelihood of environmental releases like leaks are reduced.[112] In addition, the PIPES Act of 2020 contains several provisions that specifically address the minimization of releases of natural gas from pipeline facilities, such as a mandate that the Secretary of Transportation promulgate regulations related to gas pipeline LDAR programs. More detailed information can be found at PHMSA's website: *https://www.phmsa.dot.gov/.*

The U.S. Department of Energy (DOE) develops oil and natural gas policies and funds research on advanced fuels and monitoring and measurement technologies. Specifically, the Advanced Research Projects Agency-Energy (ARPA–E) program advances high-potential, high-impact energy technologies that are too early for private-sector investment. APRA–E awardees are unique because they are developing entirely new technologies. More detailed information can be found at ARPA–E's website: *https://arpa-e.energy.gov/.* Also, the U.S. Energy Information Administration (EIA) compiles data on energy consumption, prices, including natural gas, and coal. More detailed information can be found at the EIA's website: *https://www.eia.gov/.*

The U.S. Federal Energy Regulatory Commission (FERC) is an independent agency that regulates the interstate transmission of electricity, natural gas,[113] and oil.[114] FERC also reviews proposals to build liquefied natural gas terminals and interstate natural gas pipelines as well as licensing hydropower projects. The Commission's responsibilities for the crude oil industry include the following: Regulation of rates and practices of oil pipeline companies engaged in interstate transportation; establishment of equal service conditions to provide shippers with equal access to pipeline transportation; and establishment of reasonable rates for transporting petroleum and petroleum products by pipeline. The Commission's responsibilities for the natural gas industry include the following: Regulation of pipeline, storage, and

[110] The CAA gave BOEM air jurisdiction west of 87.5° longitude in the Gulf of Mexico region.

[111] The Consolidated Appropriations Act of 2012 gave BOEM air jurisdiction in the North Slope Borough of Alaska.

[112] See Final Report on Leak Detection Study to PHMSA. December 10, 2012. *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/16691/leak-detection-study.pdf.*

[113] *https://www.ferc.gov/industries-data/natural-gas.*

[114] *https://www.ferc.gov/industries-data/oil.*

liquefied natural gas facility construction; regulation of natural gas transportation in interstate commerce; issuance of certificates of public convenience and necessity to prospective companies providing energy services or constructing and operating interstate pipelines and storage facilities; regulation of facility abandonment, establishment of rates for services; regulation of the transportation of natural gas as authorized by the Natural Gas Policy Act and OCSLA; and oversight of the construction and operation of pipeline facilities at U.S. points of entry for the import or export of natural gas. FERC has no jurisdiction over construction or maintenance of production wells, oil pipelines, refineries, or storage facilities. More detailed information can be found at FERC's website: *https://www.ferc.gov/.*

B. Industry and Voluntary Actions To Address Climate Change

Separate from regulatory requirements, some owners or operators of facilities in the Oil and Natural Gas Industry choose to participate in voluntary initiatives. Specifically, over 100 oil and natural gas companies participate in the EPA Natural Gas STAR and Methane Challenge partnership programs. Owners or operators also participate in a growing number of voluntary programs unaffiliated with the EPA voluntary programs. The EPA is aware of at least 19 such initiatives.[115] Firms might participate in voluntary environmental programs for a variety of reasons, including attracting customers, employees, and investors who value more environmental-responsible goods and services; finding approaches to improve efficiency and reduce costs; and preparing for or helping inform future regulations.[116] [117]

The EPA's Natural Gas STAR Program started in 1993 and seeks to achieve methane emission reductions through implementation of cost-effective best practices and technologies. Partner companies document their voluntary emission reduction activities and can report their accomplishments to the EPA annually. Natural Gas STAR includes over 90 partners across the natural gas value chain. Through 2019 partner companies report having eliminated nearly 1.7 trillion cubic feet of methane emissions since 1993.

The EPA's Methane Challenge Program was launched in 2016 and expands on the Natural Gas STAR Program with ambitious, quantifiable commitments and detailed, transparent reporting and partner recognition. Annually Methane Challenge partners submit facility-level reports that characterize the methane emission sources at their facilities and detail voluntary actions taken to reduce methane emissions. The EPA emphasizes the importance of transparency with the publication of these facility-level data. Although this program includes nearly 70 companies from all segments of the industry, most partners operate in the transmission and distribution segments.

Other voluntary programs for the oil and natural gas industry are administered by diverse organizations, including trade associations and non-profits. While the field of voluntary initiatives continues to grow, it is difficult to understand the present, and potential future, impact these initiatives will have on reducing methane emissions as the majority of these initiatives publish aggregated program-level data. The EPA recognizes the voluntary efforts of industry in reducing methane emissions beyond what is required by current regulations and in significantly expanding the understanding of methane mitigation measures. While progress has been made, there is still considerable remaining need to further reduce methane emissions from the Industry.

VI. Environmental Justice Considerations, Implications, and Stakeholder Outreach

To better inform this proposed rulemaking, the EPA assessed the characteristics of populations living near sources affected by the rule and conducted extensive outreach to overburdened and underserved communities and to environmental justice organizations. During our engagement with communities, concerns were raised regarding health effects of air pollutants, implications of climate change on lifestyle changes, water quality, or extreme heat events, and accessibility to data and information regarding sources near their homes. The EPA then considered this input along with other stakeholder input in designing the proposed rule. For example, one key issue identified through stakeholder input is the use of cutting-edge technologies for methane detection that can allow for rapid detection of high-emitting sources. As described below, the EPA is proposing to allow the use of such technologies in this rule, alongside a rigorous fugitive emissions monitoring program that is based on traditional OGI technology. Another key concern the Agency heard is addressing large emission sources faster, which, in addition to seeking more information on new detection technologies, the EPA is proposing to address with more frequent monitoring at sites with more emissions. The EPA also heard that adjacent communities are concerned about health impacts, and the EPA is proposing rigorous guidelines for pollution sources at existing facilities, methane standards for storage vessels, strengthened and expanded standards for pneumatic controllers, and standards for liquids unloading events that will further reduce emissions of those pollutants. These are just a few examples of how this proposed rule provides benefits to communities; section XII provides a full explanation and rationale of the proposed actions.

E.O. 12898 directs the EPA to identify the populations of concern who are most likely to experience unequal burdens from environmental harms; specifically, minority populations, low-income populations, and indigenous peoples. 59 FR 7629 (February 16, 1994). Additionally, E.O. 13985 was signed in 2021 to advance racial equity and support underserved communities—including people of color and others who have been historically underserved, marginalized, and adversely affected by persistent poverty and inequality—through Federal Government actions. 86 FR 7009 (January 20, 2021). With respect to climate change, E.O. 14008, titled ''Tackling Climate Change at Home and Abroad,'' was signed on January 27, 2021, stating that climate considerations shall be an essential element of United States foreign policy and national security, working in partnership with foreign governments, States, territories, and local governments, and communities potentially impacted by climate change. The EPA defines environmental justice (EJ) as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA further defines the term fair treatment to

[115] Highwood Emissions Management (2021). ''Voluntary Emissions Reduction Initiatives for Responsibly Sourced Oil and Gas.'' Available for download at: *https://highwoodemissions.com/research/.*

[116] Borck, J.C. and C. Coglianese (2009). ''Voluntary Environmental Programs: Assessing Their Effectiveness.'' Annual Review of Environment and Resources 34(1): 305–324.

[117] Brouhle, K., C. Griffiths, and A. Wolverton. (2009). ''Evaluating the role of EPA policy levers: An examination of a voluntary program and regulatory threat in the metal-finishing industry.'' Journal of Environmental Economics and Management. 57(2): 166–181.

mean that ''no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies'' (*https://www.epa.gov/environmentaljustice*). In recognizing that minority and low-income populations often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution emitted from sources within the Oil and Natural Gas Industry that are addressed in this proposed rulemaking.

A. Environmental Justice and the Impacts of Climate Change

In 2009, under the *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act* (''Endangerment Finding'', 74 FR 66496), the Administrator considered how climate change threatens the health and welfare of the U.S. population.[118] As part of that consideration, she also considered risks to minority and low-income individuals and communities, finding that certain parts of the U.S. population may be especially vulnerable based on their characteristics or circumstances. These groups include economically and socially disadvantaged communities, including those that have been historically marginalized or overburdened; individuals at vulnerable lifestages, such as the elderly, the very young, and pregnant or nursing women; those already in poor health or with comorbidities; the disabled; those experiencing homelessness, mental illness, or substance abuse; and/or Indigenous or minority populations dependent on one or limited resources for subsistence due to factors including but not limited to geography, access, and mobility.

Scientific assessment reports produced over the past decade by the USGCRP,[119] [120] the IPCC,[121] [122] [123] [124] the National Academies of Science, Engineering, and Medicine,[125] [126] and the EPA [127] add more evidence that the impacts of climate change raise potential EJ concerns. These reports conclude that less-affluent, traditionally marginalized and predominantly non-White communities can be especially vulnerable to climate change impacts because they tend to have limited resources for adaptation, are more dependent on climate-sensitive resources such as local water and food supplies, or have less access to social and information resources. Some communities of color, specifically populations defined jointly by ethnic/racial characteristics and geographic location (*e.g.,* African-American, Black, and Hispanic/Latino communities; Native Americans, particularly those living on Tribal lands and Alaska Natives), may be uniquely vulnerable to climate change health impacts in the U.S., as discussed below. In particular, the 2016 scientific assessment on the *Impacts of Climate Change on Human Health* [128] found with high confidence that vulnerabilities are place- and time-specific, lifestages and ages are linked to immediate and future health impacts, and social determinants of health are linked to greater extent and severity of climate change-related health impacts.

Per the NCA4, ''Climate change affects human health by altering exposures to heat waves, floods, droughts, and other extreme events; vector-, food- and waterborne infectious diseases; changes in the quality and safety of air, food, and water; and stresses to mental health and well-being.'' [129] Many health conditions such as cardiopulmonary or respiratory illness and other health impacts are associated with and exacerbated by an increase in GHGs and climate change outcomes, which is problematic as these diseases occur at higher rates within vulnerable communities. Importantly, negative public health outcomes include those that are physical in nature, as well as mental, emotional, social, and economic.

The scientific assessment literature, including the aforementioned reports, demonstrates that there are myriad ways

[118] Earlier studies and reports can be found at *https://www.epa.gov/cira/social-vulnerability-report.*

[119] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.

[120] 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.*

[121] Oppenheimer, M., M. Campos, R. Warren, J. Birkmann, G. Luber, B. O'Neill, and K. Takahashi, 2014: *Emergent risks and key vulnerabilities.* In: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 1039–1099.

[122] Porter, J.R., L. Xie, A.J. Challinor, K. Cochrane, S.M. Howden, M.M. Iqbal, D.B. Lobell, and M.I. Travasso, 2014: *Food security and food production systems. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 485–533.

[123] Smith, K.R., A. Woodward, D. Campbell-Lendrum, D.D. Chadee, Y. Honda, Q. Liu, J.M. Olwoch, B. Revich, and R. Sauerborn, 2014: Human health: impacts, adaptation, and co-benefits. In: Climate Change 2014: *Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 709–754.

[124] IPCC, 2018: Global Warming of 1.5 °C. An IPCC Special Report on the impacts of global warming of 1.5 °C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)]. In Press.

[125] National Research Council. 2011. *America's Climate Choices.* Washington, DC: The National Academies Press. *https://doi.org/10.17226/12781.*

[126] National Academies of Sciences, Engineering, and Medicine. 2017. *Communities in Action: Pathways to Health Equity.* Washington, DC: The National Academies Press. *https://doi.org/10.17226/24624.*

[127] EPA. 2021. Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. U.S. Environmental Protection Agency, EPA 430–R–21–003.

[128] USGCRP, 2016: *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment.*

[129] Ebi, K.L., J.M. Balbus, G. Luber, A. Bole, A. Crimmins, G. Glass, S. Saha, M.M. Shimamoto, J. Trtanj, and J.L. White-Newsome, 2018: Human Health. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 539–571. doi: 10.7930/NCA4.2018.CH14.

in which these populations may be affected at the individual and community levels. Outdoor workers, such as construction or utility workers and agricultural laborers, who are frequently part of already at-risk groups, are exposed to poor air quality and extreme temperatures without relief. Furthermore, individuals within EJ populations of concern face greater housing and clean water insecurity and bear disproportionate economic impacts and health burdens associated with climate change effects. They also have less or limited access to healthcare and affordable, adequate health or homeowner insurance. The urban heat island effect can add additional stress to vulnerable populations in densely populated cities who do not have access to air conditioning.[130] Finally, resiliency and adaptation are more difficult for economically disadvantaged communities: They tend to have less liquidity, individually and collectively, to move or to make the types of infrastructure or policy changes necessary to limit or reduce the hazards they face. They frequently face systemic, institutional challenges that limit their power to advocate for and receive resources that would otherwise aid in resiliency and hazard reduction and mitigation.

The assessment literature cited in the EPA's 2009 Endangerment Finding, as well as *Impacts of Climate Change on Human Health,* also concluded that certain populations and people in particular stages of life, including children, are most vulnerable to climate-related health effects. The assessment literature produced from 2016 to the present strengthens these conclusions by providing more detailed findings regarding related vulnerabilities and the projected impacts youth may experience. These assessments—including the NCA4 (2018) and *The Impacts of Climate Change on Human Health in the United States* (2016)—describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to allergens, 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 generally, these reports note that extreme weather and flooding can cause or exacerbate poor health outcomes by affecting mental health because of stress; contributing to or worsening existing conditions, again due to stress or also as a consequence of exposures to water and air pollutants; or by impacting hospital and emergency services operations.[131] Further, in urban areas in particular, flooding can have significant economic consequences due to effects on infrastructure, pollutant exposures, and drowning dangers. The ability to withstand and recover from flooding is dependent in part on the social vulnerability of the affected population and individuals experiencing an event.[132]

The Impacts of Climate Change on Human Health (USGCRP, 2016) also found that some communities of color, low-income groups, people with limited English proficiency, and certain immigrant groups (especially those who are undocumented) live with many of the factors that contribute to their vulnerability to the health impacts of climate change. While difficult to isolate from related socioeconomic factors, race appears to be an important factor in vulnerability to climate-related stress, with elevated risks for mortality from high temperatures reported for Black or African-American individuals compared to White individuals after controlling for factors such as air conditioning use. Moreover, people of color are disproportionately exposed to air pollution based on where they live, and disproportionately vulnerable due to higher baseline prevalence of underlying diseases such as asthma, so climate exacerbations of air pollution are expected to have disproportionate effects on these communities. Locations with greater health threats include urban areas (due to, among other factors, the ''heat island'' effect where built infrastructure and lack of green spaces increases local temperatures), areas where airborne allergens and other air pollutants already occur at higher levels, and communities experienced depleted water supplies or vulnerable energy and transportation infrastructure.

The recent EPA report on climate change and social vulnerability[133] examined four socially vulnerable groups (individuals who are low income, minority, without high school diplomas, and/or 65 years and older) and their exposure to several different climate impacts (air quality, coastal flooding, extreme temperatures, and inland flooding). This report found that Black and African-American individuals were 40% more likely to currently live in areas with the highest projected increases in mortality rates due to climate-driven changes in extreme temperatures, and 34% more likely to live in areas with the highest projected increases in childhood asthma diagnoses due to climate-driven changes in particulate air pollution. The report found that Hispanic and Latino individuals are 43% more likely to live in areas with the highest projected labor hour losses in weather-exposed industries due to climate-driven warming, and 50% more likely to live in coastal areas with the highest projected increases in traffic delays due to increases in high-tide flooding. The report found that American Indian and Alaska Native individuals are 48% more likely to live in areas where the highest percentage of land is projected to be inundated due to sea level rise, and 37% more likely to live in areas with high projected labor hour losses. Asian individuals were found to be 23% more likely to live in coastal areas with projected increases in traffic delays from high-tide flooding. Those with low income or no high school diploma are about 25% more likely to live in areas with high projected losses of labor hours, and 15% more likely to live in areas with the highest projected increases in asthma due to climate-driven increases in particulate air pollution, and in areas with high projected inundation due to sea level rise.

Impacts of Climate Change on Indigenous Communities. Indigenous communities face disproportionate risks from the impacts of climate change, particularly those communities impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Indigenous communities whose health, economic well-being, and cultural traditions depend upon the natural

[130] USGCRP, 2016.

[131] Ebi, K.L., J.M. Balbus, G. Luber, A. Bole, A. Crimmins, G. Glass, S. Saha, M.M. Shimamoto, J. Trtanj, and J.L. White-Newsome, 2018: Human Health. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 539–571. doi: 10.7930/NCA4.2018.CH14.

[132] National Academies of Sciences, Engineering, and Medicine 2019. Framing the Challenge of Urban Flooding in the United States. Washington, DC: The National Academies Press. *https://doi.org/10.17226/25381.*

[133] EPA. 2021. Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. U.S. Environmental Protection Agency, EPA 430–R–21–003.

environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The IPCC indicates that losses of customs and historical knowledge may cause communities to be less resilient or adaptable.[134] The NCA4 (2018) noted that while indigenous peoples are diverse and will be impacted by the climate changes universal to all Americans, there are several ways in which climate change uniquely threatens indigenous peoples' livelihoods and economies.[135] In addition, there can be institutional barriers (including policy-based limitations and restrictions) to their management of water, land, and other natural resources that could impede adaptive measures.

For example, indigenous agriculture in the Southwest is already being adversely affected by changing patterns of flooding, drought, dust storms, and rising temperatures leading to increased soil erosion, irrigation water demand, and decreased crop quality and herd sizes. The Confederated Tribes of the Umatilla Indian Reservation in the Northwest have identified climate risks to salmon, elk, deer, roots, and huckleberry habitat. Housing and sanitary water supply infrastructure are vulnerable to disruption from extreme precipitation events. Confounding general Native American response to natural hazards are limitations imposed by policies such as the Dawes Act of 1887 and the Indian Reorganization Act of 1934, which ultimately restrict Indigenous peoples' autonomy regarding land-management decisions through Federal trusteeship of certain Tribal lands and mandated Federal oversight of management decisions. Additionally, NCA4 noted that Indigenous peoples are subjected to institutional racism effects, such as poor infrastructure, diminished access to quality healthcare, and greater risk of exposure to pollutants. Consequently, Native Americans often have disproportionately higher rates of asthma, cardiovascular disease, Alzheimer's disease, diabetes, and obesity. These health conditions and related effects (*e.g.,* disorientation, heightened exposure to $PM_{2.5}$, etc.) can all contribute to increased vulnerability to climate-driven extreme heat and air pollution events, which also may be exacerbated by stressful situations, such as extreme weather events, wildfires, and other circumstances.

NCA4 and IPCC's Fifth Assessment Report[136] also highlighted several impacts specific to Alaskan Indigenous Peoples. Coastal erosion and permafrost thaw will lead to more coastal erosion, rendering winter travel riskier and exacerbating damage to buildings, roads, and other infrastructure—impacts on archaeological sites, structures, and objects that will lead to a loss of cultural heritage for Alaska's indigenous people. In terms of food security, the NCA4 discussed reductions in suitable ice conditions for hunting, warmer temperatures impairing the use of traditional ice cellars for food storage, and declining shellfish populations due to warming and acidification. While the NCA4 also noted that climate change provided more opportunity to hunt from boats later in the fall season or earlier in the spring, the assessment found that the net impact was an overall decrease in food security.

B. Impacted Stakeholders

Based on analyses of exposed populations, the EPA has determined that this action, if finalized in a manner similar to what is proposed in this document, is likely to help reduce adverse effects of air pollution on minority populations, and/or low-income populations that have the potential for disproportionate impacts, as specified in E.O. 12898 (59 FR 7629, February 16, 1994) and referenced in E.O. 13985 (86 FR 7009, January 20, 2021). The EPA remains committed to engaging with communities and stakeholders throughout the development of this rulemaking and continues to invite comments on how the Agency can better achieve these goals through this action. For this proposed rule, we assessed emissions of HAP, criteria pollutants, and pollutants that cause climate change.

For HAP emissions, we estimated cancer risks and the demographic breakdown of people living in areas with potentially elevated risk levels by performing dispersion modeling of the most recent NEI data from 2017, which indicates nationwide emissions of approximately 110,000 tpy of over 40 HAP (including benzene, toluene, ethylbenzene, xylenes, and formaldehyde) from the Oil and Natural Gas Industry. Table 12 gives the risk and demographic results for the Oil and Natural Gas Industry from this screening-level assessment. We estimate there are 39,000 people with cancer risk greater than or equal to 100-in-1 million attributable to oil and natural gas sources, with a maximum estimated risk of 200-in-1 million occurring in three census blocks (10 people). We estimate there are about 143,000 people with estimated risk greater than or equal to 50-in-1 million, and about 6.8 million people with estimated cancer risk greater than 1-in-1 million. It is important to note that these estimates are subject to various types of uncertainty related to input parameters and assumptions, including emissions datasets, exposure modeling and the dose-response relationships.[137]

As shown in Table 12, Hispanic and Latino populations and young people (ages 0–17) are disproportionately represented in communities exposed to elevated cancer risks from oil and natural gas sources, while the proportion of people in other demographic groups with estimated risks above the specified levels is at or below the national average. The overall percent minority is about the same as the national average, but the percentage of people exposed to cancer risks greater than or equal to the 100-in-1 million and 50-in-1 million thresholds who are Hispanic or Latino is about 10 percentage points higher than the national average. The overall minority percentage is not elevated compared to the national average because the African-American percentage is much lower than the national average. The demographic group of people aged 0–17 is slightly higher than the national average.

[134] Porter et al., 2014: Food security and food production systems.

[135] Jantarasami, L.C., R. Novak, R. Delgado, E. Marino, S. McNeeley, C. Narducci, J. Raymond-Yakoubian, L. Singletary, and K. Powys Whyte, 2018: Tribes and Indigenous Peoples. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 572–603. doi: 10.7930/NCA4. 2018. CH15.

[136] Porter et al., 2014: Food security and food production systems.

[137] See 'Risk Report Template' at Docket ID No. EPA–HQ–OAR–2021–0317.

TABLE 12—CANCER RISK AND DEMOGRAPHIC POPULATION ESTIMATES FOR 2017 NEI NONPOINT OIL AND NATURAL GAS EMISSIONS

	Risks ≥100-in-1 million		Risks ≥50-in-1 million		Risks >1-in-1 million		Nationwide
Total Population	39,000		143,000		6,805,000		
	Population	%	Population	%	Population	%	%
Minority	13,268	34.1	52,154	36.5	2,010,161	29.5	39.9
African American	140	0.4	1,434	1.0	535,055	7.9	12.2
Native American	77	0.2	465	0.3	59,087	0.9	0.7
Other and Multiracial	1,443	3.7	5,148	3.6	323,397	4.8	8.2
Hispanic or Latino	11,608	29.9	45,107	31.6	1,092,621	16.1	18.8
Age 0–17	10,679	27.5	37,487	26.2	1,463,907	21.5	22.6
Age ≥65	4,272	11.0	17,188	12.0	1,085,067	15.9	15.7
Below the Poverty Level	2,000	5.1	13,455	9.4	902,472	13.2	13.4
Over 25 Without a High School Diploma	2,788	7.2	11,320	7.9	488,372	7.2	12.1
Linguistically Isolated	808	2.1	4,418	3.1	179,739	2.6	5.4

For criteria pollutants, we assessed exposures to ozone from Oil and Natural Gas Industry VOC emissions across races/ethnicities, ages, and sexes in a recent baseline (pre-control) air quality scenario. Annual air quality was simulated using a photochemical model for the year 2017, based on emissions from the most recent NEI. The analysis shows that the distribution of exposures for all demographic groups except Hispanic and Asian populations are similar to or below the national average or a reference population. Differences between exposures in Hispanic and Asian populations versus White or all populations are modest, and the results are subject to various types of uncertainty related to input parameters and assumptions.

In addition to climate and air quality impacts, the EPA also conducted analyses to characterize potential impacts on domestic oil and natural gas production and prices and to describe the baseline distribution of employment and energy burdens. Section XVI.d describes the results for our analysis of prices and production. For the distribution of baseline employment, we assessed the demographic characteristics of (1) workers in the oil and gas sector and (2) people living in oil and natural gas intensive communities.[138] Comparing workers in the oil and natural gas sector to workers in other sectors, oil and natural gas workers may have higher than average incomes, be more likely to have completed high school, and be disproportionately Hispanic. People in some oil and gas intensive communities concentrated in Texas, Oklahoma, and Louisiana have lower average income levels, lower rates of high school completion, and higher likelihood of being non-Whites or hispanic than people living in communities that are not oil and gas intensive. Regarding household energy burden, low-income households, Hispanic, and Black households' energy expenditures may comprise a disproportionate share of their total expenditures and income as compared to higher income, non-Hispanic, and non-Black households, respectively. Results are presented in detail in the RIA accompanying this proposal.

In a proximity analysis of Tribes living within 50 miles of affected sources, we found 112 unique Tribal lands (Federally recognized Reservations, Off-Reservation Trust Lands, and Census Oklahoma Tribal Statistical Areas (OTSA)) located within 50 miles of a source with 32 Tribes having one or more sources located on Tribal land.

Finally, the EPA has also analyzed prior enforcement actions related to air pollution from storage vessels, and identified improvements in air quality resulting from these actions as particularly important in communities with EJ concerns (identified using EJSCREEN).[139] In a 2021 analysis of resolved enforcement matters, the EPA determined that communities with EJ concerns experience a disproportionate level of air pollution burden from storage vessel emissions. Although only about 25 percent of storage vessels were located in these communities with EJ concerns, 67 percent of the total emission reductions of VOCs, methane, PM, and NO_X (about 95 million pounds) achieved through these enforcement resolutions occurred in communities with EJ concerns. This analysis suggests that the provisions of this proposed rule requiring installation of controls at storage vessels and monitoring and mitigation of fugitive emissions and malfunctions at storage vessels, would have particular benefits for these communities.

C. Outreach and Engagement

The EPA identified stakeholder groups likely to be interested in this action 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. Specifically, on May 27, 2021, the EPA held a webinar-based training designed for communities affected by this rule.[140] 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.[141 142] Community themes

[138] For this analysis, oil and natural gas intensive communities are defined as the top 20% of communities with respect to the proportion of oil and natural gas workers.

[139] See Memorandum ''Analysis of Environmental Justice Impacts of EPA's Historical Oil and Gas Storage Vessel Enforcement Resolutions (40 CFR part 60 subpart OOOO and OOOOa),'' located at Docket ID No. EPA–HQ–OAR–2021–0317.

[140] *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.*

[141] June 15, 2021 session: *https://youtu.be/T8XwDbf-B8g*; June 16, 2021 session: *https://www.youtube.com/watch?v=l23bKPF-5oc*; June 17,

Continued

included concerns about protecting communities adjacent to oil and gas activities, providing monitoring and data so communities know what is in the air they are breathing, and upholding Tribal trust responsibilities. Community speakers urged the EPA to adopt stringent measures to reduce oil and natural gas pollution, and frequently cited an analysis suggesting such measures could achieve reductions of 65 percent below 2012 levels by 2025.

Community Access to Emissions Information. Several stakeholders requested that the rule include requirements that provide communities with information, including fence line monitoring or ''better monitoring so people will know the air they are breathing.'' A few speakers expressed concerned about the correct placement of existing air monitors. Speakers from Texas described local air monitors monitoring meteorology and ozone, but not hazardous air pollutants, and called on the EPA to consider alternative monitoring for oil and natural gas sources such as fence-line monitors, along with guidance from the EPA to require monitors of oil and natural gas facilities in close proximity to parks, schools, and playgrounds.

Health Concerns in Adjacent Communities. Speakers raised concerns about impacts on frontline communities and those communities adjacent to oil and natural gas operations. These stakeholders called on the EPA to propose and promulgate stricter standards or alternative requirements for sources adjacent to urban communities and close to where people live and work. Several speakers used the term ''energy sacrifice zone'' when discussing the disproportionate impacts of oil and natural gas operations on frontline communities. Speakers advocated that when developing this regulatory effort, consultation with frontline communities is essential, and some speakers cited a Center for Investigative Reporting report stating that 30,000 children in Arlington, Texas, attend school within half a mile of active oil and gas sites. Speakers discussed concerns about methane as a formaldehyde precursor and related health effects and cited examples of health effects including hydraulic fracturing chemicals being measured in blood or urine; increases in nosebleeds in people in areas of oil and natural gas development; headaches and cancer.

These speakers included teenagers from Pennsylvania, who said they live within 1 mile of 33 wellheads and 500 feet of a pipeline. Several people cited a February 2018 blowout and explosion in Belmont County, Ohio, that was reported to release 60,000 tons of methane in 20 days and said that is more than some countries emit in a year. Speakers also expressed related environmental concerns such as water contamination and fresh drinking water being diverted for hydraulic fracturing. One speaker urged that information on local water use be provided in languages other than English, stating that in Big Spring (Howard County), Texas, the local government only provided information to use tap water ''at your own risk'' in English.

Additional concerns raised by communities included: Local compressor stations having numerous planned and unplanned releases into adjacent communities, which appear to be during startup; whether the EPA will use a robust cost analysis to address the economic impacts of labor loss and gas costs resulting from any regulation; if plugged and abandoned wells included in this action, will this regulation apply to BLM land; will States be required to use the same emissions calculation used by the EPA for methane GWP; will there be disclosure of necessary data collection or technology to be used by the Oil and Natural Gas Industry to track and reduce methane emissions; and will the EPA consider the necessity of venting and flaring from a safety standpoint. Communities also discussed concerns about excess emissions from storage vessels and the need for clarifying the applicability of the standard in addition to improving enforceability and compliance at this type of facility.

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. As noted above, the EPA provided the public with factual information to help them understand the issues addressed by this action. 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 this proposed action.

In addition to the engagement conducted prior to this proposal, the EPA is providing 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 public hearings. This public hearing will occur according to the schedule identified in the **DATES** and **SUPPLEMENTARY INFORMATION** section of this preamble to 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.

For more information about the EPA's pre-proposal outreach activities, please see EPA Docket ID No. EPA–HQ–OAR–2021–0295. Please refer to EPA Docket ID No. EPA–HQ–OAR–2021–0317 for submitting public comments on this proposed rulemaking. 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.

D. Environmental Justice Considerations

The EPA considered EJ implications in the development of this proposed rulemaking process, including the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income. As part of this process, the EPA engaged and consulted with frontline communities through interactions such as webinars, listening sessions and meetings. These opportunities gave the EPA a chance to hear directly from the public, especially overburdened and underserved communities, on the development of the proposed rule. The EPA considered these community concerns throughout our internal development process that resulted in this proposal which, if finalized in a manner similar to what is being proposed, will reduce emissions of harmful air pollutants, promote gas capture and beneficial use, and provide opportunity for flexibility and expanded transparency in order to yield a consistent and accountable national program. The EPA's proposed NSPS and EG are summarized in sections XI and XII below. Anticipated impacts of this action are discussed further in section XVI of this preamble.

In recognizing that minority and low-income populations often bear an unequal burden of environmental harms and risks, the EPA continues to consider

2021 session: *https://www.youtube.com/watch?v=R2AZrmfuAXQ.*

[142] Full transcripts for the listening sessions are posted at EPA Docket ID No. EPA–HQ–OAR–2021–0295.

ways to protect them from adverse public health and environmental effects of air pollution emitted from sources within the Oil and Natural Gas Industry that are addressed in this proposed rulemaking. For these reasons, in section XIV.C the EPA is proposing to include an additional requirement associated with the adoption and submittal of State plans pursuant to EG OOOOc (in addition to the current requirements of Subpart Ba) by requiring States to meaningfully engage with members of the public, including overburdened and underserved communities, during the plan development process and prior to adoption and submission of the plan to the EPA. The EPA is proposing this specific meaningful engagement requirement to ensure that the State plan development process is inclusive, effective, and accessible to all.

Details of the EPA's assessment of EJ considerations can be found in the RIA for this action. The EPA seeks input on the EJ analyses contained in the RIA, as well as broader input on other health and environmental risks the Agency should assess in the comprehensive development of this proposed action. In particular, the EPA is soliciting comment on key assumptions underlying the EJ analysis as well as data and information that would enable the Agency to conduct a more nuanced analysis of HAP and criteria pollutant exposure and risk, given the inherent uncertainty regarding risk assessment. More broadly, the EPA seeks information, analysis, and comment on how the provisions of this proposed action would affect air pollution and health in communities with environmental justice concerns, and whether there are further provisions that EPA should consider as part of a supplemental proposal or a final rule that would enhance the health and environmental benefits of this rule for these communities.

VII. Other Stakeholder Outreach

A. Educating the Public, Listening Sessions, and Stakeholder Outreach

The EPA began the development of this proposed action to reduce methane and other harmful pollutants from new and existing sources in the Crude Oil and Natural Gas source category with a public outreach effort to gather a broad range of stakeholder input. This effort included: Opening a public docket for pre-proposal input; [143] holding training sessions providing overviews of the industry, the EPA's rulemaking process and how to participate in it; and convening listening sessions for the public, including a wide range of stakeholders. The EPA additionally held roundtables with State environmental commissioners through the Environmental Council of the States, and oil and gas commissioners and staff through the Interstate Oil and Gas Compact Commission (IOGCC), and met with non-governmental organizations (NGOs), industry, and the U.S. Climate Alliance, among others.[144]

In addition to the trainings and listening sessions noted in section VI above, on May 25 and 26, 2021, the EPA held webinar-based trainings designed for small business stakeholders [145] and Tribal nations.[146] The training provided an overview of the Oil and Natural Gas Industry and how it is regulated and offered information on how to participate in the rulemaking process. A combined total of more than 100 small business stakeholders and Tribal nations participated. During the training, small business stakeholders expressed interest in learning more about the EPA's plan to either modify the 2016 NSPS OOOOa or take more substantial action in this proposal. For Tribal nations, the EPA has assessed potential impacts on Tribal nations and populations and has engaged with Tribal stakeholders to hear concerns associated with air pollution emitted from sources within the Oil and Natural Gas Industry that are addressed in this proposed rulemaking. Tribal members mentioned the need for the EPA to uphold its trust responsibilities, propose and promulgate rules that protect disproportionately impacted communities, and asked that the EPA allocate resources for Tribal governments to implement regulations through Tribal air quality programs.

As noted above, the EPA also heard from a broad range of stakeholders during virtual public listening sessions held from June 15 through June 17, 2021,[147] which featured a total of 173 speakers.[148] Many speakers stressed the urgent need to address climate change and the importance of reducing methane pollution as part of the nation's overall response to climate change. In addition to the community perspectives described above, the Agency also heard from industry speakers who were generally supportive of the regulation and stressed the need to provide compliance flexibility and allow industry the ability to use cutting-edge tools, including measurement tools, to implement requirements. Technical comments from other speakers also focused on a need for robust methane monitoring and fugitive emissions monitoring, a need to strengthen standards for flares as a control for associated gas, and suggestions to improve compliance. The sections below provide additional details on the information presented by stakeholders during these listening sessions.

1. Technical Themes

Measurement and Monitoring. Stakeholders advocated that the EPA modernize the rule by employing next-generation tools for methane identification and quantification, particularly for large emission or ''super-emissions'' events. Stakeholders particularly focused on allowing the use of remote sensing to help industry more easily comply with monitoring requirements at well pads, which are numerous and geographically spread out in some States. Stakeholders specified the desire to use innovative remote sensing technologies to monitor fugitive emissions and large emission events, including aerial, truck-based, satellite, and continuous monitoring. Several speakers focused on the need for regular monitoring, repair, and reporting, including ambient air monitoring in oil and natural gas development areas, as well as suggesting that the EPA pursue more robust methane monitoring for fugitive emissions, ensure that repair is completed, and pursue robust monitoring and reporting to verify the efficacy of the regulations.

Implementation, Compliance, and Enforcement. Numerous stakeholders raised concerns about flaring of associated gas and advocated for more stringent standards to ensure that flares used as control devices perform effectively. One speaker, an OGI expert, noted seeing many flares that were not operating the way they were intended to and that were not adequately designed (*e.g.,* unlit flares and ignition gas not being close enough to the waste gas stream to properly ignite). The speaker suggested that the EPA consider the concept of 'thermal tuning' of flares by

[143] EPA Docket ID No. EPA–HQ–OAR–2021–0295.

[144] A full list of pre-proposal meetings the EPA participated in is included at EPA Docket ID No. EPA–HQ–OAR–2021–0317.

[145] *https://www.epa.gov/sites/default/files/2021-05/documents/oil_and_gas_training_webinar_small_businesses_05.25.21.pdf.*

[146] *https://www.epa.gov/sites/default/files/2021-05/documents/usepa_training_webinar_on_oil_and_natural_gas_for_tribes.5.26.2021.pdf.*

[147] 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.*

[148] Full transcripts for the listening sessions are posted in at EPA Docket ID No. EPA–HQ–OAR–2021–0295.

using OGI to see if a plume of unburned hydrocarbons extends downwind from the flare, to ensure that flares are actually operating effectively; the speaker suggested that this use of OGI could be done in conjunction with fugitive emissions monitoring to make sure controls are working. Stakeholders further emphasized the need for recordkeeping of any inspections that are made (*e.g.,* looking for flare damage from burned tips, lightning strikes). Some stakeholders also requested that the EPA consider reducing or eliminating flaring of associated gas and incentivizing capture. Lastly, one speaker raised concerns about flaring of associated gas in Texas and how flaring is permitted by the State. In response to these concerns, the EPA is proposing to reduce venting and flaring of associated gas and to require monitoring of flares to detect malfunctions. Further, the EPA is soliciting comment on whether to adopt additional measures to assure proper design and operation of control devices, including flares, as discussed in section XIII.

Stakeholders raised other implementation, compliance, and enforcement concerns, including calls for the EPA to develop rules that are easy to apply and implement given States' limited budgets. Stakeholders cautioned that ''flexibility'' in a rule can be interpreted as a ''loophole,'' and opined that a rule that sets clear and uniform expectations will help avoid confusion. At the same time, speakers stated that a ''prescriptive checklist'' does not work in today's environment and recommended that the EPA modernize the regulatory approach. Several speakers, including speakers from Texas and North Dakota, raised concerns about the limited enforcement capacity of local and State governments, as well as the EPA and its regional officials and stated that this may result in implementation gaps. Speakers called on the EPA to have a third-party verification or audit requirements for fugitive emissions and cited to Texas's requirement for third-party audits to evaluate operator LDAR programs for highly reactive VOC. Speakers also cited to the public-facing Environmental Defense Fund (EDF) methane map [149] with geotags of sources with observed hydrocarbon emissions, which provides operators an opportunity to respond to posted leak videos and measurements. Lastly, one speaker requested that the EPA not allow exemptions for start-up and shutdown emissions events. The EPA is soliciting comment on ways to utilize credible emissions information obtained from communities and others, as discussed in section XI.A.1.

Wells and Storage. Some stakeholders requested that the EPA consider a program for capping abandoned wells to ensure those wells are properly closed and not leaking. Speakers called on the EPA to consider abandoned and unplugged wells in the context of EJ communities adjacent to affected facilities and requested that the EPA incentivize appropriate well closure. In response to this input and to gather information that will be needed to inform possible future actions, the EPA is soliciting comment on ways to address abandoned wells, including potential closure requirements. See section XIII.B. Stakeholders also focused on marginal wells and asked that the EPA consider system-wide reductions be allowed, for example, at the basin level, and expressed challenges of retrofitting existing well sites and low production well sites where addition of control devices or closed vent systems would be necessary. Some speakers raised concern about ensuring that facilities are engineered for the basin or target formation from which they produce.

Job Creation. Some speakers stated that this rulemaking is a job creation rule and encouraged a ''next generation'' approach to methane standards, such as incentivizing continuous monitoring. Other speakers cited a study about job creation in the methane mitigation industry.[150]

Inventory, Loss Rates, and Methane Global Warming Potential. Several speakers criticized the EPA's emission inventories stating that the EPA is not using the correct data in its inventory, that the GHGI data is inaccurate because it relies on facility reporting of emissions from calculations and estimation methods rather than measurement and monitoring, and suggested that the EPA rely on monitoring and measurement of actual emissions and subsequently make the monitoring data publicly available. Speakers raised issues with differences in inventories across Federal agencies, contrasting DOE's Environmental Impact Statements and EPA's NEI. Stakeholders suggested that the EPA use data collected by EDF and other researchers, which calculated methane emissions to be 60 percent higher than the EPA's estimates.[151] Speakers also mentioned the amount of methane that is lost from wells each year, providing varying estimates of these emissions. Lastly, stakeholders called on the EPA to use the 20-year GWP for methane, instead of the 100-year value the agency uses.

2. Climate and Other Themes

Several speakers mentioned the effects of climate change from oil and natural gas methane emissions, such as impacts on farmland, wildfires, and transmission of tick-borne pathogens. Many speakers pointed out the extreme heat and drought that currently are affecting the western U.S. Stakeholders asked that the EPA examine the impacts of the Oil and Natural Gas Industry on small businesses that are not part of the regulated community, such as businesses that rely on outdoor recreation or water flow that could be affected by oil and natural gas operations. A speaker raised concerns about the impact of the industry on tourism, saying that 30 percent of their local economy relies on tourism and outdoor recreation. Lastly, a speaker discussed pipeline weatherization needs and suggested that the EPA and other Federal agencies account for seasonal variability.

In addition to the public listening sessions, on June 29, 2021, the EPA met with environmental commissioners and staff through the Environmental Council of the States (ECOS). Subsequently, on July 12, 2021, the EPA participated in a roundtable with members of the IOGCC. The discussions in both roundtables included air emissions monitoring technologies and interactions between the EPA's requirements and State rules. For the ECOS roundtable, the EPA also sought feedback on and implementation of the EPA's current NSPS; for the IOGCC roundtable, the EPA also requested feedback on compliance with the rules.

Key themes from both roundtables included the following: Allowing for the use of broad types of methane detection technologies; improving and streamlining the EPA's AMEL process, such as by structuring it so it could apply broadly rather than on a site-by-site basis; requests that expanded aspects of States' rules be deemed equivalent to the EPA's rule, and requests that the EPA's rule complement State regulations in a way that would not interrupt the work of State agencies requiring them to request State legislative approvals. Other common themes were requests that the rule

[149] *https://www.permianmap.org.*

[150] Stakeholders submitted the following studies to the pre-proposal docket: *https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0295-0016* and *https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0295-0017.*

[151] Alvarez et al. 2018. *Assessment of methane emissions from the U.S. oil and gas supply chain.* Science 13 Jul 2018: Vol. 361, Issue 6398, pp. 186–188.

provide flexibility and be easy to implement, particularly for marginal or low production wells owned by independent small businesses, and that the EPA coordinate its rules with those of other Federal agencies, notably the DOI's BLM.

Other input included the need to fill gaps by addressing additional opportunities to reduce emissions beyond the 2016 NSPS OOOOa, concerns about the complexity of the calculation for the potential to emit for storage vessels, a desire that the EPA's rule not slow momentum of voluntary efforts to reduce emissions, and a desire for regulations that recognize geographic differences.

B. EPA Methane Detection Technology Workshop

The EPA held a virtual public workshop on August 23 and 24, 2021, to hear perspectives on innovative technologies that could be used to detect methane emissions from the Oil and Natural Gas Industry.[152] The workshop focused on methane-sensing technologies that are not currently approved for use in the NSPS for the Oil and Natural Gas Industry, and how those technologies could be applied in the Crude Oil and Natural Gas sector. Panelists provided twenty-four live presentations during the workshop. The panelists all had firsthand experience evaluating innovative methane-sensing technologies or had used these technologies to identify methane emissions and presented about their experience. The live presentations were broken into six panel sessions, each focused on a particular topic, *e.g.,* satellite measurements, methane sensors, aerial technologies. At the end of each panel session, the set of panelists participated in a question-and-answer session. In addition to the live presentations, the workshop included a virtual exhibit hall for technology vendors to provide video presentations on their innovative technologies, with a focus on technology capability, applicability, and data quality. Forty-two vendors participated in the virtual vendor hall.

Nine hundred sixty stakeholders registered to participate in the workshop. The workshop was also livestreamed, so stakeholders who could not attend could watch the recorded livestream later at their convenience. The registrants included a wide range of stakeholders including, academics, methane detection technology end-user and vendors, governmental employees (local, State, and Federal), and NGOs.

C. How is this information being considered in this proposal?

The EPA's pre-proposal outreach effort was intended to gather stakeholder input to assist the Agency with developing this proposal.[153] The EPA recognizes that tackling the dangers of climate change will require an ''all-hands-on deck'' approach through regulatory, voluntary, and community programs and initiatives. Throughout the development of this proposed rule, 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. The EPA will continue to consider the information obtained in developing this proposal as we take the next steps on the proposed regulations.

With this proposal, the EPA seeks further input from the public and from all stakeholders affected by this rule. Throughout this action, unless noted otherwise, the EPA is requesting comments on all aspects of this proposal, including on several themes raised in the pre-proposal outreach (*e.g.,* innovative technologies for methane detection and quantification). Please see section XI.A.1 of this preamble for specific solicitations for comment regarding advanced measurement technologies and section XIII for solicitations for comments on additional emission sources. For public input to be considered on this proposal,[154] please submit comments on this proposed action to the 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.

VIII. Legal Basis for Proposal Scope

The EPA proposes in this rulemaking to revise certain NSPS and to promulgate additional NSPS for both methane and VOC emissions from new oil and gas sources in the production, processing, transmission and storage segments of the industry; and to promulgate EG to require States to regulate methane emissions from existing sources in those segments. The large amount of methane emissions from the Oil and Natural Gas Industry—by far, the largest methane-emitting industry in the nation—coupled with the adverse effects of methane on the global climate compel immediate regulatory action. This section explains EPA's legal justification for proceeding with this proposed action, including regulating methane and VOCs from sources in all segments of the source category. The EPA first describes the history of our regulatory actions for oil and gas sources in 2016 and 2020—including the key legal interpretations and factual determinations made—as well as Congress's action in 2021 in response. The EPA then explains the implications of Congress's action and why we would come to the same conclusion even if Congress had not acted.

This proposal is in line with our 2016 NSPS OOOOa rule, which likewise regulated methane and VOCs from all three segments of the industry. The 2016 NSPS OOOOa rule explained that these three segments should be regulated as part of the same source category because they are an interrelated sequence of functions in which pollution is produced from the same types of sources that can be controlled by the same techniques and technologies. That rule further explained that the large amount of methane emissions, coupled with the adverse effects of GHG air pollution, met the applicable statutory standard for regulating methane emissions from new sources through NSPS. Furthermore, the rule explained, this regulation of methane emissions from new sources triggered the EPA's authority and obligation to set guidelines for States to develop standards to regulate the overwhelming majority of oil and gas sources, which the CAA categorizes as ''existing'' sources. In the 2020 Policy Rule, the Agency reversed course, concluding based upon new legal interpretations that the rule concluded the EPA had not made the proper determinations necessary to issue such regulations. This action eliminated the Agency's authority and obligation to issue EG for existing sources. In 2021, Congress adopted a joint resolution to disapprove the EPA's 2020 Policy Rule under the CRA. According to the terms of CRA, the 2020 Policy Rule is ''treated as though [it] had never taken effect,'' 5 U.S.C. 801(f), and as a result, the 2016 Rule is reinstated.

In disapproving the 2020 Policy Rule under the CRA, Congress explicitly rejected the 2020 Policy Rule interpretations and embraced EPA's

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[152] *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop.*

[153] The EPA opened a non-regulatory docket for stakeholder to submit early input. That early input can be found at EPA Docket I.D. Number EPA–HQ–OAR–2021–0295.

[154] Information submitted to the pre-proposal non-regulatory docket at Docket ID No. EPA–HQ–OAR–2021–0295 is not automatically part of the proposal record. For information and materials to be considered in the proposed rulemaking record, it must be resubmitted in the rulemaking docket at EPA Docket ID No. EPA–HQ–OAR–2021–0317.

rationales for the 2016 NSPS OOOOa rule. The House Committee on Energy & Commerce emphasized in its report that the source category ''is the largest industrial emitter of methane in the U.S.,'' and directed that ''regulation of emissions from new and existing oil and gas sources, including those located in the production, processing, and transmission and storage segments, is necessary to protect human health and welfare, including through combatting climate change, and to promote environmental justice.'' H.R. Rep. No. 117–64, 3–5 (2021) (House Report). A statement from the Senate cosponsors likewise underscored that ''methane is a leading contributing cause of climate change,'' whose ''emissions come from all segments of the Oil and Gas Industry,'' and stated that ''we encourage EPA to strengthen the standards we reinstate and aggressively regulate methane and other pollution emissions from new, modified, and existing sources throughout the production, processing, transmission and storage segments of the Oil and Gas Industry under section 111 of the CAA.'' 167 Cong. Rec. S2282 (April 28, 2021) (statement by Sen. Heinrich) (Senate Statement).[155] The Senators concluded with a stark statement: ''The welfare of our planet and of our communities depends on it.'' *Id.* at S2283.

This proposal comports with the EPA's CAA section 111 obligation to reduce dangerous pollution and responds to the urgency expressed by the current Congress. With this proposal, the EPA is taking additional steps in the regulation of the Crude Oil and Natural Gas source category to protect human health and the environment. Specifically, the agency is proposing to revise certain of those NSPS, to add NSPS for additional sources, and to propose EG that, if finalized, would impose a requirement on States to regulate methane emissions from existing sources. As the EPA explained in the 2016 Rule, this source category collectively emits massive quantities of the methane emissions that are among those driving the grave and growing threat of climate change, particularly in the near term. 81 FR 35834, June 3, 2016. As discussed in section III above, since that time, the science has repeatedly confirmed that climate change is already causing dire health, environmental, and economic impacts in communities across the United States.

Because the 2021 CRA resolution automatically reinstated the 2016 Rule, which itself determined that the Crude Oil and Natural Gas Source Category included the transmission and storage segment and that regulation of methane emissions was justified, the EPA is authorized to take the regulatory actions proposed in this rule. As explained below, we are reaffirming those determinations as clearly authorized under any reasonable interpretation of section 111. Because the reinstatement of the 2016 Rule provides the only necessary predicate for this rule, and because, as described, the interpretations underlying this rule are sound, the EPA is not reopening them here.

A. Recent History of the EPA's Regulation of Oil and Gas Sources and Congress's Response

1. 2016 NSPS OOOOa Rule

As described above, the 2016 NSPS OOOOa rule extended the NSPS for VOCs for new sources in the Crude Oil and Natural Gas source category and also promulgated NSPS for methane emissions from new sources. This rule contained several interpretations that were the bases for these actions, and that are important for present purposes. First, the EPA confirmed its position in the 2012 NSPS OOOO rule that the scope of the oil and gas source category included the transmission and storage segment, in addition to the production and processing segments that the EPA had regulated since 1984. The agency stated that it believed these segments were included in the initial listing of the source category, and to the extent they were not, the agency determined to add them as appropriately encompassed within the regulated source category. The EPA based this latter conclusion on the structure of the industry. In particular, the EPA emphasized that ''[o]perations at production, processing, transmission, and storage facilities are a sequence of functions that are interrelated and necessary for getting the recovered gas ready for distribution,'' and further explained, ''[b]ecause they are interrelated, segments that follow others are faced with increases in throughput caused by growth in throughput of the segments preceding (*i.e.,* feeding) them.'' 81 FR 35832, June 3, 2016. The EPA also recognized ''that some equipment (*e.g.,* storage vessels, pneumatic pumps and compressors) are used across the oil and natural gas industry.'' *Id.* Having made clear that the Crude Oil and Natural Gas source category includes the transmission and storage segment, the EPA proceeded to promulgate NSPS for sources in that segment. *Id.* at 35826.

Second, in promulgating NSPS for methane emissions for new sources in the source category, the EPA explained its decision to regulate GHGs for the first time from the source category. Noting that the plain language of CAA section 111 requires a significant-contribution analysis only when EPA regulates a new source category, not a new pollutant, the Agency stated that it ''interprets CAA section 111(b)(1)(B) to provide authority to establish a standard for performance for any pollutant emitted by that source category as long as the EPA has a rational basis for setting a standard for the pollutant.'' 81 FR 35842, June 3, 2016. In the alternative, if a rational-basis analysis were deemed insufficient, the EPA explained that it also concluded that GHG emissions, in the form of methane emissions, from the regulated Crude Oil and Natural Gas source category significantly contribute to dangerous pollution. *Id.* at 81 FR 35843, and 35877. In making the rational basis and alternative significant contribution findings, the EPA focused on ''the high quantities of methane emissions from the Crude Oil and Natural Gas source category.'' *Id.* The EPA emphasized, among other things, that ''[t]he Oil and Natural Gas source category is the largest emitter of methane in the U.S., contributing about 29 percent of total U.S. methane emissions.'' *Id.* The EPA added that ''[t]he methane that this source category emits accounts for 3 percent of all U.S. GHG emissions . . . [and] GWP-weighted emissions of methane from these sources are larger than emissions of all GHGs from about 150 countries.'' *Id.* The EPA concluded that ''the[se] facts . . . along with prior EPA analysis'' concerning the effect of GHG air pollution on public health and welfare, ''including that found in the 2009 Endangerment Finding, provide a rational basis for regulating GHG emissions from affected oil and gas sources . . .'' as well as for concluding in the alternative that oil and gas methane significantly contributes to dangerous pollution. *Id.* at 35843.

In addition, in the 2016 NSPS OOOOa Rule, EPA recognized that promulgation of NSPS for methane emissions under

[155] Sen. Heinrich stated that he made this statement on behalf of ''[Majority [l]eader Chuck Schumer, Chairman Tom Carper of the Committee on Environment and Public Works, Senator Angus King, Senator Edward Markey and [himself],'' who he described as ''leading supporters and sponsors of S.J. Res. 14. . . .'' Senate Statement at S. 2282. Thus, the Senate Statement should be considered an authoritative piece of the legislative history. It should be noted that the Joint Resolution was referred to the Senate Committee on Environment and Public Works and discharged from the committee by petition pursuant to 5 U.S.C. 802(c), *https://www.congress.gov/bill/117th-congress/senate-joint-resolution/14/all-actions.* As a result, the resolution was not accompanied by a report from the Senate committee.

section 111(b)(1)(B) triggered the requirement that EPA promulgate EG to require States to regulate methane emissions from existing sources under section 111(d)(1), and described the steps it was taking to lay the groundwork for that regulation. 81 FR at 35831.

2. 2020 Policy Rule

The 2020 Policy Rule rescinded key elements of the 2016 NSPS OOOOa rule based on different factual assertions and statutory interpretations than in the 2016 Rule. Specifically, the 2020 Policy Rule stated that it ''contains two main actions,'' 85 FR 57019, September 14, 2020 which it identified as follows: ''First, the EPA is finalizing a determination that the source category includes only the production and processing segments of the industry and is rescinding the standards applicable to the transmission and storage segment of the industry. . . .'' *Id.* The rule justified this first action in part on the grounds that ''the processes and operations found in the transmission and storage segment are distinct from those found in the production and processing segments,'' because ''the purposes of the operations are different'' and because ''the natural gas that enters the transmission and storage segment has different composition and characteristics than the natural gas that enters the production and processing segments.'' *Id.* at 57028. ''Second, the EPA is separately rescinding the methane requirements of the NSPS applicable to sources in the production and processing segments.'' *Id.* EPA justified the rescission of the methane NSPS on two grounds. One was the EPA's ''conclu[sion] that those methane requirements are redundant with the existing NSPS for VOC and, thus, establish no additional health protections.'' *Id.* at 57019. The second was a statutory interpretation: the EPA rejected the rational basis interpretation of the 2016 Rule, and stated that instead, ''[t]he EPA interprets [the relevant provisions in CAA section 111] . . . to require, or at least to authorize the Administrator to require, a pollutant-specific SCF as a predicate for promulgating a standard of performance for that air pollutant.'' Id. at 57035. The rule went on to ''determine that the SCF for methane that the EPA made in the alternative in the 2016 [NSPS OOOOa] Rule was invalid and did not meet this statutory standard,'' for two reasons: (i) ''[t]he EPA made that finding on the basis of methane emissions from the production, processing, and transmission and storage segments, instead of just the production and processing segments''; and (ii) ''the EPA failed to support that finding with either established criteria or some type of reasonably explained and intelligible standard or threshold for determining when an air pollutant contributes significantly to dangerous air pollution.'' *Id.* at 57019. The rule recognized that ''by rescinding the applicability of the NSPS . . . to methane emissions for [oil and gas] sources . . . existing sources . . . will not be subject to regulation under CAA section 111(d).'' *Id.* at 57040.

3. CRA Resolution Disapproving the 2020 Policy Rule and Reinstating the 2016 NSPS OOOOa Rule

On June 30, 2021, the President signed into law a joint resolution adopted by Congress under the CRA disapproving the 2020 Policy Rule. By the terms of the CRA, this disapproval means that the 2020 Policy Rule is ''treated as though [it] had never taken effect.'' 5 U.S.C. 801(f). As a result, upon the disapproval, by operation of law, the 2016 NSPS OOOOa rule was reinstated, including the inclusion of the transmission and storage segment in the source category, the VOC NSPS for sources in that segment, and the methane NSPS for sources across the source category. And with the reinstatement of the methane NSPS, the EPA's obligation to issue EG to require States to regulate existing sources for methane emissions was reinstated as well. Moreover, the CRA bars an agency from promulgating ''a new rule that is substantially the same as'' a disapproved rule. 5 U.S.C. 801(b)(2).

The accompanying legislative history, specifically a House Committee report (H.R. Rep. 117–64) and a statement on the Senate floor by the sponsors of the CRA resolution (Senate Statement at S2282–83), provides additional specificity regarding Congress's intent in disapproving 2020 Policy Rule and reinstating the 2016 Rule with regard to the scope of the source category and the regulation of methane.

a. Regulation of Transmission and Storage Sources

The House Report rejected the 2020 Policy Rule's removal of the transmission and storage segment from the Crude Oil and Natural Gas Source Category, and its rescission of the VOC and methane NSPS promulgated in the 2012 NSPS OOOO and 2016 NSPS OOOOa rules for transmission and storage sources. House Report at 7; 85 FR 57029, September 14, 2020 (2020 Policy Rule). The Report recognized that in authorizing the EPA to list for regulation ''categories of sources'' under section 111(b)(1)(A) of the CAA, Congress ''provided the EPA with wide latitude to determine the scope of a source category . . . and to expand the scope of an already-listed source category if the agency later determines that it is reasonable to do so.'' House Report at 7. The Report stated that in the 2016 NSPS OOOOa, ''EPA correctly determined that the equipment and operations at production, processing, and transmission and storage facilities are a sequence of functions that are interrelated and necessary for the overall purpose of extracting, processing, and transporting natural gas for distribution.'' *Id.;* see 81 FR 35832, June 3, 2016 (2016 Rule). The Report added that the 2016 NSPS OOOOa also ''correctly determined that the types of equipment used and the emissions profile of the natural gas in the transmission and storage segments do not so distinctly differ from the types of equipment used and the emissions profile of the natural gas in the production and processing segments as to require that the EPA create a separate source category listing.'' House Report at 7; see 81 FR 35832, June 3, 2016. The Report went on to reject the 2020 Policy Rule's basis for excluding the transmission and storage segment, finding that the functions of the various segments in the Crude Oil and Natural Gas sector are all ''interrelated and necessary for the overall purpose'' of the industry, House Report at 7, and that EPA correctly determined in 2016 that the source types and emissions found in the transmission and storage segment are sufficiently similar to production and processing as to justify regulating these segments in a single source category. *Id.*

The Senate Statement was also explicit that the 2020 Policy Rule erred in rescinding NSPS for sources in the transmission and storage segment:

> [T]he resolution clarifies our intent that EPA should regulate methane and other pollution emissions from all oil and gas sources, including production, processing, transmission, and storage segments under the authority of section 111 of the CAA. In addition, we intend that section 111 . . . obligates and provides EPA with the legal authority to regulate existing sources of methane emissions in all of these segments.

Senate Statement at S2283 (paragraphing revised).

b. Regulation of Methane—Redundancy

The House Report and Senate Statement made clear Congress's view that in light of the large amount of methane emissions from oil and gas sources and their impact on global climate, the EPA must regulate those emissions under section 111. House Report at 5; Senate Statement at S2283. Both pieces of legislative history specifically rejected the 2020 Policy Rule's rescission of the methane NSPS. House Report at 7; Senate Statement at S2283. Moreover, the legislative history specifically rejected the statutory interpretations of section 111 that formed the bases of EPA's 2020 rationales for rescinding the methane NSPS. House Report at 7–10; see Senate Statement at S2283; see 85 FR 57033, 57035–38 (September 14, 2020).

The House Report began by recognizing the critical importance of regulating methane emissions from oil and gas sources, emphasizing both the potency of methane in driving global warming, and the massive amounts of methane emitted each year by the oil and gas industry. House Report at 3–4. The House Report was clear that the amount of these emissions and their impact compelled regulatory action. *Id.* at 5. The Senate Statement was equally clear:

> [M]ethane is a leading contributing cause of climate change. It is 28 to 36 times more powerful than carbon dioxide in raising the Earth's surface temperature when measured over a 100–year time scale and about 84 times more powerful when measured over a 20–year timeframe.
>
> Industrial sources emit GHG in great quantities, and methane emissions from all segments of the Oil and Gas Industry are especially significant in their contribution to overall emissions levels and surface temperature rise. . . .
>
> In fact, with the congressional adoption of this resolution, we encourage EPA to strengthen the standards we reinstate and aggressively regulate methane and other pollution emissions from new, modified, and existing sources throughout the production, processing, transmission, and storage segments of the Oil and Gas Industry under section 111 of the Clean Air Act.
>
> The welfare of our planet and of our communities depend on it.

Senate Statement at S2283.

Turning to the 2020 Policy Rule, the House Report rejected the rule's position that the methane NSPS were redundant to the VOC NSPS, and therefore unnecessary. House Report at 7. The House Report rejected the 2020 Policy Rule's ''redundancy'' rationale, explaining that in the 2016 NSPS OOOOa, the EPA had consciously ''formulated [the two sets of NSPS so as] to impose the same requirements for the same types of equipment,'' and that the co-extensive nature of the NSPS mean that ''sources could comply with them in an efficient manner,'' not that the NSPS were redundant. *Id.* The House report further rejected the 2020 Policy Rule's assertion that it need not take into account the implications of regulating methane for existing sources, calling it a ''fundamental misinterpretation of section 111, and the critical importance of section 111(d) in Congress [*sic:* Congress's] scheme.'' House Report at 8 & n. 27 (The EPA's 2020 ''misinterpretation . . . was glaring and enormously consequential'' because it precluded regulation of methane from existing sources). The House Report emphasized that ''existing sources emit the vast majority of methane in the oil and gas sector,'' *id.* and pointed out that while the 2016 NSPS ''covered roughly 60,000 wells constructed since 2015[, t]here are more than 800,000 existing wells in operation. . . .''*Id.* n.28.

The Senate Statement also made clear that the resolution of disapproval ''reaffirms that the CAA requires EPA to act to protect Americans from sources of . . . methane,'' ''reject[s] the [2020 Policy Rule's] misguided legal interpretations,'' and ''clarifies our intent that EPA should regulate methane . . . from all oil and gas sources. . . .'' Senate Statement at 2283.

c. Regulation of Methane—Significant Contribution Finding

The legislative history was explicit that, contrary to the EPA's statutory interpretation in the 2020 Policy Rule, section 111 of the CAA, by its plain language, does not require, or authorize the EPA to require, as a prerequisite for promulgating NSPS for a particular air pollutant from a listed source category, a separate finding by the EPA that emissions of the pollutant from the source category contribute significantly to dangerous air pollution. House Report at 9–10; Senate Statement at S2283. The House Report rejected this interpretation. It made clear that instead, consistent with the EPA's statements in the 2016 NSPS OOOOa and the plain language of the CAA, section 111 requires that the agency must make a SCF only at ''the first step of the process, the listing of the source category,'' and further requires that this finding ''must apply to the impact of the 'category of sources' on 'air pollution' '' as opposed to individual pollutants. House Report at 9. The House Report went on to explain that this provision ''does not require the EPA to make a SCF for individual air pollutants emitted from the source category, nor does it even mention individual air pollutants,'' *id.* at 9. The House Report went on to explain in some detail the meaning that the EPA should give to section 111, which, consistent with the 2016 Rule, is that section 111 authorizes the agency to promulgate NSPS for particular pollutants as long as it has a rational basis for doing so. House Report at 8–9. The report explained that after the EPA lists a source category for regulation under section 111(b)(1)(A), it is required to determine for which pollutants to promulgate NSPS, and this determination is subject to CAA section 307(d)(9)(A) (''In the case of review of any [EPA] action . . . to which [section 307(d)] applies, the court may reverse any such action found to be arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law'').[156] The Report further noted that the U.S. Supreme Court affirmed this interpretation in *American Electric Power Co. Inc.* v. *Connecticut,* 564 U.S. 410, 427 (2011) (*American Electric Power*) (''EPA may not decline to regulate carbon-dioxide emissions from powerplants if refusal to act would be 'arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law'' (citing section 307(d)(9)(A)). The Report went on to note that the 2016 NSPS OOOOa had stated that the EPA was authorized to promulgate a NSPS for a particular pollutant if it had a ''rational basis'' for doing so, and the Report emphasized that this ''rational basis'' standard is ''fully consistent with'' the arbitrary and capricious standard under section 307(d)(9)(A) of the CAA. House Report at 9.[157]

The House Report further explained that, in contrast, the 2020 Policy Rule's statutory interpretation of section 111 to require a pollutant-specific SCF as a predicate for promulgating NSPS was foreclosed by ''the plain language of'' section 111—noting that this interpretation ignored the distinction between the text of section 111 and that of other CAA provisions which do explicitly require a pollutant-specific cause-or-contribution finding. *Id.* at 10. Moreover, the Report added, ''[g]iven that the statute is not ambiguous, the EPA cannot interpret section 111 to authorize the EPA to exercise discretion to require . . . a pollutant-specific SCF as a predicate for promulgating a [NSPS] for the pollutant.'' *Id.* at 10. The Report went on to note several other supports for its statutory interpretation, including the legislative history of section 111. *Id.* at 10–11.

The Senate Statement took the same approach, stating: ''we do not intend that section 111 of [the] CAA requires EPA to make a pollutant-specific

[156] Section 307(d) applies to the promulgation of NSPS, under section 307(d)(1)(C).

[157] The House Report dismissed the 2020 Policy Rule's criticism of the rational basis test as unduly vague by noting that a court could enforce it. House Report at 11.

significant contribution finding before regulating emissions of a new pollutant from a listed source category. . . .'' Senate Statement at S2283.[158]

The House Report also expressly disapproved of the 2020 Policy Rule's interpretation of section 111 to require that the SCF must be based on some ''identif[ied] standard or established set of criteria,'' and not the facts-and-circumstances approach that EPA has used in making that finding for the source category. House Report at 10–11; *see* 2020 Policy Rule at 57038. The Report stated, ''[i]t 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.'' House Report at 11.

Finally, in reinstating the methane regulations, the legislative history for the CRA resolution clearly expressed the intent that the EPA proceed with regulation of existing sources. The House Report was explicit in this regard, stating that ''[p]assage of the resolution of disapproval indicates Congress' support and desire to immediately reinstate . . . EPA's statutory obligation to regulate existing oil and natural gas sources under [CAA] section 111(d).'' House Report at 3; see *id.* at 11–12. The report added that upon enactment of the resolution of disapproval, ''the Committee strongly encourages the EPA to take swift action to . . . fulfill its statutory obligation to issue existing source guidelines under [CAA] section 111(d).'' *Id.* The Senate Statement was substantially similar. Senate Statement at S2283 (''By adopting this resolution of disapproval, it is our view that Congress reaffirms that the CAA requires EPA to act to protect Americans from sources of climate pollution like methane, which endangers the public's health and welfare. . . . [W]e intend that [CAA] section 111 . . . obligates and provides EPA with the legal authority to regulate existing sources of methane emissions in [the Crude Oil and Natural Gas source category].'').

[158] Both the House Report and the Senate Statement recognized that EPA could, if it chose to, make a finding that a particular pollutant contributes significantly to dangerous air pollution, in order, for example, to inform the public about the risks of a pollutant. House Report at 10, Senate Statement at S2283. However, the House Report made clear that ''it is the rational basis determination as to the risk a pollutant poses to endangerment of human health or welfare [and not any such SCF] that remains the statutory basis for the EPA's action.'' House Report at 10.

B. Effect of Congress's Disapproval of the 2020 Policy Rule

Under the CRA, the disapproved 2020 Policy Rule is ''treated as though [it] had never taken effect.'' 5 U.S.C. 801(f). As a result, the preceding regulation, the 2016 NSPS OOOOa rule, was automatically reinstated, and treated as though it had never been revised by the 2020 Policy Rule. Moreover, the CRA bars EPA from promulgating ''a new rule that is substantially the same as'' a disapproved rule. 5 U.S.C. 801(b)(2), for example, a rule that deregulates methane emissions from the production and processing sectors or deregulates the transmission and storage sector entirely.

The legislative history of the CRA gives further content to Congress's disapproval and the bar on substantially similar rulemaking. The legislative history rejected the EPA's statutory interpretations of section 111 in the 2020 Policy Rule and endorsed the legal interpretations contained in the 2016 NSPS OOOOa rule. Specifically, Congress expressed its intent that the transmission and storage segment be included in the source category, that sources in that segment remain subject to NSPS, and that all oil and gas sources be subject to NSPS for methane emissions.[159]

The EPA is now proceeding to propose additional requirements to reduce emissions from oil and gas sources, consistent with the statutory factors the EPA is required to consider under section 111 and with section 111's overarching purpose of protecting against pollution that endangers health and welfare. While the reinstatement of the 2016 Rule through the CRA joint resolution of disapproval provides the predicate for this action, the EPA notes that, for the reasons discussed next, the EPA would reject the positions concerning legal interpretations taken in the 2020 Policy Rule and reaffirm the positions the Agency took in the 2016 Rule even absent the CRA resolution. The EPA provides this information for the purposes of informing the public and is not re-opening these positions for comment.

C. Affirming the Legal Interpretations in the 2016 NSPS OOOOa Rule

The Agency has reviewed all of the information and analyses in the 2016 NSPS OOOOa and 2020 Policy Rule, and fully reaffirms the positions it took in the 2016 Rule and rejects the positions taken in the 2020 Policy Rule.[160] For this rulemaking, the EPA has reviewed its prior actions, along with newly available information, including recent information concerning the dangers posed by climate change and the impact of methane emissions, as described in section III above. Based on this review, the EPA affirms the statutory interpretations underlying the 2016 Rule and rejects the different interpretations informing the congressionally voided 2020 Policy Rule. This section explains the EPA's views. These views are confirmed by Congress's reasoning in the legislative history of the CRA resolution and so, for convenience, this section occasionally refers to that legislative history.

[159] See generally ''Federal-State Unemployment Compensation Program; Establishing Appropriate Occupations for Drug Testing of Unemployment Compensation Applicants Under the Middle-Class Tax Relief and Job Creation Act of 2012: Final Rule,'' 84 FR 53037, 53083 (Oct. 4, 2019) (citing legislative history of CRA resolution disapproving prior rule in explaining scope of new rule).

In particular, the EPA reaffirms that the Crude Oil and Natural Gas Source Category appropriately includes the transmission and storage segment, along with the production and processing segments. The EPA has broad discretion in determining the scope of the source category, and the 2016 Rule correctly identified the most important aspect of the industry, which is the interrelatedness of the segments and their common purpose in completing the multi-step process to prepare natural gas for marketing. 81 FR 35832, June 3, 2016. The 2020 Policy Rule's objection that the chemical composition of natural gas changes as it moves from the production and processing segments to the transmission and storage segment, 85 FR 57028, September 14, 2020, misses the mark because in every segment methane predominates and the refining of natural gas in the processing segment, which is what changes its chemical composition, is appropriately viewed simply as one of the steps in the marketing of the gas. Further, while it is true that some of the equipment in each segment differs from the equipment in the other segments, as the 2020 Policy Rule pointed out, 85 FR 57029 (September 14, 2020), that too simply results from the fact that the segments represent different steps in the process of preparing natural gas for marketing. The more salient fact is that most of the polluting equipment, such as storage

[160] Under *F.C.C.* v. *Fox Television Stations, Inc.,* 556 U.S. 502 (2009), an agency may revise its policy, but must demonstrate that the new policy is permissible under the statute and is supported by good reasons, taking into account the record of the previous rule. To the extent that this standard applies in this action—where Congress has disapproved the 2020 Policy Rule—the EPA believes the explanations provided here satisfy the standard.

vessels, pneumatic pumps, and compressors, are found throughout the segments and emit the same pollutants that can be controlled by the same techniques and technologies, 81 FR 35832 (June 3, 2016), underscoring the interrelated functionality of the segments and the appropriateness of regulating them together as part of a single source category. The scope of the source category as defined in 2016, and proposed to be affirmed in this rule, is well within the reasonable bounds of the EPA's past practice in defining source categories, which sometimes even contain sources that are located in multiple distinct industries. *See* 40 CFR part 60, subpart Db (industrial-commercial-institutional steam generating units), 40 CFR part 60, subpart IIII (stationary compression ignition internal combustion engines). In this regard, the House Report correctly noted that ''even the presence of large distinctions in equipment type and emissions profile across two segments would not necessarily preclude EPA from regulating those segments as a single source category, so long as the EPA could identify some meaningful relationship between them,'' House Report at 7, as the EPA did in the 2016 Rule. Thus, the 2020 Policy Rule failed to articulate appropriate reasons to change the scope of the source category from what the EPA determined in the 2016 Rule. Having properly identified the scope of the source category as including the transmission and storage segment in the 2016 Rule, the EPA lawfully promulgated NSPS for sources in that segment.

The EPA also affirms that the 2016 Rule established an appropriate basis for promulgating methane NSPS from oil and gas sources, and that the 2020 Policy Rule erred on all grounds in rescinding the methane NSPS. The importance of taking action at this time, in accordance with the requirements of CAA section 111, to reduce the enormous amount of methane emissions from oil and gas sources, in light of the impacts on the climate of this pollution, cannot be overstated. As stated in section I, the Oil and Natural Gas Industry is the largest industrial emitter of methane in the U.S. Human emissions of methane, a potent GHG, are responsible for about one third of the warming due to well-mixed GHGs, the second most important human warming agent after carbon dioxide. According to the IPCC, strong, rapid, and sustained methane reductions are critical to reducing near-term disruption of the climate system and a vital complement to CO_2 reductions critical in limiting the long-term extent of climate change and its destructive impacts.[161] The EPA previously determined, in the 2016 NSPS OOOOa rule, both that it had a rational basis to regulate methane emissions from the source category, and, in the alternative, that methane emissions from the Crude Oil and Natural Gas Source Category, contribute significantly to dangerous air pollution. 81 FR 35842–43, (June 3, 2016). The EPA is not reopening those determinations for comment in the present rulemaking.

Contrary to the statements in the 2020 Policy Rule, the methane NSPS promulgated in the 2016 Rule cannot be said to be redundant with the VOC NSPS and therefore unnecessary. The large contribution of methane emissions from the source category to dangerous air pollution driving the grave and growing threat of climate change means that, in the agency's judgment, it would be highly irresponsible and also arbitrary and capricious under CAA section 307(d)(9)(A) for the EPA to decline to promulgate NSPS for methane emissions from the source category. *See American Electric Power,* 564 U.S. at 426–27. The fact that the EPA designed the methane NSPS so that sources could comply with them efficiently, through the same actions that the sources needed to take to comply with the VOC NSPS, did not thereby create redundancy. Further, the fact that methane NSPS but not the VOC NSPS trigger the regulatory requirements for existing sources makes clear that the two sets of requirements are not redundant. Indeed, if EPA had only regulated VOCs, it would only have been authorized to regulate new and modified sources, which comprise a small subset of polluting sources. By contrast, because the 2016 Rule also regulated methane, EPA was authorized and obligated to regulate hundreds of thousands of additional ''existing'' sources that comprise the vast majority of polluting sources. Accordingly, methane regulation was not ''redundant'' of VOC regulation. The 2020 Policy Rule's contrary position was based on a misinterpretation of CAA section 111 which overlooked that the provision integrates requirements for new and existing sources. See *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 433 n.48 (D.C. Cir. 1980) (CAA section 111(b)(1)(A) listing of a source category is based on emissions from new and existing sources).

The EPA also reaffirms the 2016 Rule's statutory interpretation that the EPA is authorized to promulgate a NSPS for an air pollutant under CAA section 111(b)(1)(B) in a situation in which the EPA has previously determined that the source category causes or contributes significantly to dangerous air pollution and where the EPA has a rational basis for regulating the particular air pollutant in question that is emitted by the source category. 81 FR 35842 (June 3, 2016). The 2016 Rule noted the precedent in prior agency actions for the position that—following the listing of a source category—the EPA need provide only a rational basis for its exercise of discretion for which pollutants to regulate under section 111(b)(1)(B). *See id.* (citing *National Lime Assoc.* v. *EPA,* 627 F.2d 416, 426 & n.27 (D.C. Cir. 1980) (court discussed, but did not review, the EPA's reasons for not promulgating standards for NO_X, SO_2, and CO from lime plants). In addition, the Supreme Court in *American Electric Power* provided support for the rational basis statutory interpretation. 564 U.S. at 426–27 (''EPA [could] decline to regulate carbon-dioxide emissions altogether at the conclusion of its . . . [CAA section 111] rulemaking,'' and such a decision ''would not escape judicial review,'' under the ''arbitrary and capricious'' standard of section 307(d)(9)(A)). As the House Report noted, the EPA's rational basis interpretation ''is fully consistent with the provision[s] of section 111 and the section 307(d)(9) 'arbitrary and capricious' standard.'' House Report at 9.

The 2020 Policy Rule correctly noted that the CAA section 111(b)(1)(B) requirement that the EPA ''shall promulgate . . . standards [of performance]'' for air pollutants, coupled with the CAA section 111(a)(1) definition for ''standard of performance'' as, in relevant part, a ''standard for emissions of air pollutants,'' does not by its terms require that EPA promulgate NSPS for every air pollutant from the source category. But the rule erred in seeking to graft the CAA section 111(b)(1)(A) requirement for a SCF into CAA section 111(b)(1)(B). The language of CAA section 111(b)(1)(A) is clear: It requires the EPA Administrator to ''include a *category of sources* in [the list for regulation] if in his judgment it causes, or contributes to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' (Emphasis added.) Congress thus specified that the required SCF is made

[161] See preamble section III for further discussion on the Crude Oil and Natural Gas Emissions and Climate Change, including discussion of the GHGs, VOCs and SO_2 Emissions on Public Health and Welfare.

on a category basis, not a pollutant-specific basis, and that once that finding is made (as it was for the Crude Oil and Natural Gas source category in 1979), the EPA may establish standards for pollutants emitted by the source category. In determining for which air pollutants to promulgate standards of performance, the EPA must act rationally, which, as noted above, essentially must ensure that the action does not fail the ''arbitrary and capricious'' standard under CAA section 307(d)(9)(A). The 2020 Policy Rule's objections to the rational basis standard on grounds that is ''vague and not guided by any statutory criteria,'' 85 FR 57034 (September 14, 2020), is incorrect. In making a rational basis determination, the EPA has considered the amount of the air pollutant emitted by the source category, both in absolute terms and by drawing comparisons, as well as the availability of control technologies. *See National Lime Assoc.* v. *EPA,* 627 F.2d 416, 426 & n.27 (D.C. Cir. 1980) (discussing EPA's reasons for not promulgating standards for NO_X, SO_2 and CO from lime plants); 80 FR 64510, 64530 (October 23, 2015) (rational basis determination for GHGs from fossil fuel-fired electricity generating power plants); 73 FR 35838, 35859–60 (June 24, 2008) (providing reasons why the EPA was not promulgating GHG standards for petroleum refineries). Courts routinely review rules under the ''arbitrary and capricious'' standard, as noted in the House Report, at 11.

When the EPA is required to make an endangerment finding, the EPA also affirms that that finding should be made in consideration of the particular facts and circumstances, not a predetermined threshold. Accordingly, the EPA rejects the 2020 Policy Rule's position to the contrary. Section 111(b)(1)(A) of the CAA does not require that the SCF for the source category be based on ''established criteria'' or ''standard or threshold.'' *See Coal. for Responsible Regulation, Inc.* v. *EPA,* 684 F.3d 102, 122–23 (D.C. Cir. 2012) (''the inquiry [into whether an air pollutant endangers] necessarily entails a case-by-case, sliding-scale approach. . . . EPA need not establish a minimum threshold of risk or harm before determining whether an air pollutant endangers''). During the 50 years that it has made listing decisions, the EPA has always relied on the individual facts and circumstances. *See Alaska Dep't of Envtl. Conservation,* 540 U.S. 461, 487 (2004) (explaining, in a case under the CAA, ''[w]e normally accord particular deference to an agency interpretation of longstanding duration'' (internal quotation marks omitted) (citing *Barnhart* v. *Walton,* 535 U.S. 212, 220 (2002)). This approach is appropriate because Congress intended that CAA section 111 apply to a wide range of source categories and pollutants, from wood heaters to emergency backup engines to petroleum refineries. In that context, it reasonable to interpret section 111 to allow EPA the discretion to determine how best to assess significant contribution and endangerment based on the individual circumstances of each source category. On this point, as well, the EPA is in full agreement with the statements in the House Report. House Report at 9–10.

Finally, under CAA section 111(d)(1), once the EPA promulgates NSPS for certain air pollutants, including GHGs, the EPA is required to promulgate regulations, which the EPA terms EG, 40 CFR 60.22a, that in turn require States to promulgate standards of performance for existing sources of those air pollutants. The EPA agrees with the House Report and Senate statement that it is imperative to regulate methane emissions from the existing oil and gas sources that comprise the vast majority of polluting sources expeditiously under the authority of CAA section 111(d) and is proceeding with the process to do so in this rulemaking by publishing proposed EG. See section III.B.2. In 2019, the GHGI estimates for oil and natural gas production, and natural gas processing and transmission and storage segments that methane emissions equate to 182 MMT CO_2 Eq.[162] 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.

Some stakeholders have raised issues concerning the scope of pollutants subject to CAA section 111(d) by arguing that the exclusion in CAA section 111(d) for HAP covers not only those pollutants listed for regulation under CAA section 112, but also precludes the EPA from regulating a source category under CAA section 111(d) for *any* pollutant if that source category has been regulated under CAA section 112. The EPA agrees with its longstanding legal interpretation spanning multiple Administrations that the 111(d) exclusion does not preclude the agency from regulating a non-HAP pollutant from a source category under section 111(d) even if that source category is regulated under section 112. See *American Lung Ass'n* v. *EPA,* 980 F.3d 914, 980 (D.C. Cir. 2019) (referring to ''EPA's three-decade-old . . . reading of the statutory amendments''), *petition for cert. pending* No. 20–1530 (filed April 29, 2021); 70 FR 15994, 16029 (March 29, 2005) (Clean Air Mercury Rule); 80 FR 64662, 64710 (Oct. 23, 2015) (Clean Power Plan); 84 FR 32520 (July 8, 2019) (Affordable Clean Energy Rule). The House Report agreed with this interpretation, noting that the contrary position is flawed because it ignores the overall statutory structure that Congress created in the CAA and would create regulatory gaps in which the EPA would not be able to regulate existing sources for some pollutants (such as methane) under CAA section 111(d) if those sources (but not pollutants) were already regulated for different pollutants under CAA section 112. House Report at 11–12. Moreover, the D.C. Circuit recently considered this precise issue and held that the EPA may both regulate a source category for HAP under CAA section 112 and regulate that same source category for different pollutants under CAA section 111(d). *Am. Lung Assoc.,* 985 F.3d at 977–988. Accordingly, both Congress and the court have come to the same conclusion after reviewing the statutory language, a conclusion that is aligned with the EPA's longstanding position. We therefore proceed in the proposal to propose EGs for existing sources in the oil and gas source category.

IX. Overview of Control and Control Costs

A. Control of Methane and VOC Emissions in the Crude Oil and Natural Gas Source Category—Overview

As described in this action, the EPA reviewed the standards in the 2016 NSPS OOOOa pursuant to CAA section 111(b)(1)(B). Based on this review, the EPA is proposing revisions to the standards for a number of affected facilities to reflect the updated BSER for those affected facilities. Where our analyses show that the BSER for an

[162] The 100-year GWP value of 25 for methane indicates that one ton of methane has approximately as much climate impact over a 100-year period as 25 tons of CO_2. The most recent IPCC AR6 assessment has estimated a slightly larger 100-year GWP of methane of almost 30 (specifically, either 27.2 or 29.8 depending on whether the value includes the CO_2 produced by the oxidation of methane in the atmosphere). As mentioned earlier, because methane has a shorter lifetime than CO_2, the emissions of a ton of methane will have more impact earlier in the 100-year timespan and less impact later in the 100-year timespan relative to the emissions of a 100-year GWP-equivalent quantity of CO_2. See preamble section III for further discussion on the Crude Oil and Natural Gas Emissions and Climate Change, including discussion of the GHGs, VOCs and SO_2 Emissions on Public Health and Welfare.

affected facility remains the same, the EPA is proposing to retain the current standard for that affected facility. In addition to the actions on the standards in the 2016 NSPS OOOOa described in this section, the EPA is proposing standards for GHGs (in the form of limitation on methane) and VOCs for a number of new sources that are currently unregulated. The proposed NSPS OOOOb would apply to new, modified, and reconstructed emission sources across the Crude Oil and Natural Gas source category for which construction, reconstruction, or modification is commenced after November 15, 2021.

Further, pursuant to CAA section 111(d), the EPA is proposing EG, which include presumptive standards for GHGs (in the form of limitations on methane) (designated pollutant), for certain existing emission sources across the Crude Oil and Natural Gas source category in the proposed EG OOOOc. While the proposed requirements in NSPS OOOOb would apply directly to new sources, the proposed requirements in EG OOOOc are for States to use in the development of plans that establish standards of performance that will apply to existing sources (designated facilities).

B. How does EPA evaluate control costs in this action?

Section 111 of the CAA requires that the EPA consider a number of factors, including cost, in determining ''the best system of emission reduction . . . adequately demonstrated.'' CAA section 111(a)(1). The D.C. Circuit has long recognized that ''[CAA] section 111 does not set forth the weight that [ ] should [be] assigned to each of these factors;'' therefore, ''[the court has] granted the agency a great degree of discretion in balancing them.'' *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999) (''*Lignite Energy Council*''). In *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973) *(''Essex Chemical''*), the court noted that ''it is not unlikely that the industry and the EPA will disagree on the economic costs of various control techniques'' and that it ''has no desire or special ability to settle such a dispute.'' *Id.* at 437. Rather, the court focused its review on ''whether the standards as set are the result of reasoned decision-making.'' *Id.* at 434. A standard that ''is the result of the exercise of reasoned discretion by the Administrator [ ] cannot be upset by this Court.'' *Id.* at 437.

As noted, CAA section 111 requires that the EPA consider cost in determining such system (*i.e.,* ''BSER''), but it does not prescribe any criteria for such consideration. The courts have recognized that the EPA has ''considerable discretion under [CAA] section 111,'' *Lignite Energy Council,* 198 F.3d at 933, on how it considers cost under CAA section 111(a)(1). For example, in *Essex Chemical,* the D.C. Circuit 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.'' 486 F.2d at 433. The court has reiterated this limit in subsequent case law, including *Lignite Energy Council,* in which it stated: ''EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant.'' 198 F.3d at 933. In *Portland Cement Association* v. *Train,* the court elaborated by explaining that the inquiry is whether the costs of the standard are ''greater than the industry could bear and survive.''[163] 513 F.2d 506, 508 (D.C. Cir. 1975). In *Sierra Club* v. *Costle,* the court provided a substantially similar formulation of the cost factor: ''EPA concluded that the Electric Utilities' forecasted cost was not excessive and did not make the cost of compliance with the standard unreasonable. This is a judgment call with which we are not inclined to quarrel.'' 657 F.2d 298, 343 (D.C. Cir. 1981). We believe that these various formulations of the cost factor—''exorbitant,'' ''greater than the industry could bear and survive,'' ''excessive,'' and ''unreasonable''—are synonymous; the D.C. Circuit has made no attempt to distinguish among them. For convenience, in this rulemaking, we will use the term ''reasonable'' to describe that our evaluation of costs is well within the boundaries established by this case law.

In evaluating whether the cost of a control is reasonable, the EPA considers various costs associated with such control, including capital costs and operating costs, and the emission reductions that the control can achieve. As discussed further below, the agency considers these costs in the context of the industry's overall capital expenditures and revenues. Cost-effectiveness analysis is also a useful metric, and a means of evaluating whether a given control achieves emission reduction at a reasonable cost. A cost-effectiveness analysis also allows comparisons of relative costs and outcomes (effects) of two or more options. In general, cost-effectiveness is a measure of the outcomes produced by resources spent. In the context of air pollution control options, cost-effectiveness typically refers to the annualized cost of implementing an air pollution control option divided by the amount of pollutant reductions realized annually. A cost-effectiveness analysis is not intended to constitute or approximate a benefit-cost analysis in which monetized benefits are compared to costs, but rather provides a metric to compare the relative cost and emissions impacts of various control options.

The estimation and interpretation of cost-effectiveness values is relatively straightforward when an abatement measure is implemented for the purpose of controlling a single pollutant, such as for the controls included as presumptive standards in the proposed EG OOOOc to address methane emissions from existing sources in the Crude Oil and Natural Gas source category. In other circumstances, air pollution reduction programs require reductions in emissions of multiple pollutants, as with the NSPS for the Crude Oil and Natural Gas source category, which regulates both GHG and VOC. In such cases, multipollutant controls (controls that achieve reductions of both pollutants through the same techniques and technologies) may be employed, and consequently, there is a need for determining cost-effectiveness for a control option across multiple pollutants (or classes of multiple pollutants).

During the rulemaking for NSPS OOOOa, we evaluated a number of approaches for considering the cost-effectiveness of the available multipollutant controls for reducing both methane and VOC emissions. See 80 FR 56593, 56616 (September 18, 2015). In that rulemaking, we used two approaches for considering the cost-effectiveness of control options that reduce both VOC and methane emissions; we are proposing to use these same two cost-effectiveness approaches, along with other factors discussed further below, in considering the cost of requiring control for the proposed NSPS OOOOb. One approach, which we refer to as the ''single pollutant cost-effectiveness approach,'' assigns all costs to the emission reduction of one pollutant and zero to all other concurrent reductions. If the cost is reasonable for reducing any of the

[163] The 1970 Senate Committee Report on the Clean Air Act stated: ''The implicit consideration of economic factors in determining whether technology is 'available' should not affect the usefulness of this section. The overriding purpose of this section would be to prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach.'' S. Comm. Rep. No. 91–1196 at 16.

targeted pollutants alone, the cost of such control is clearly reasonable for the concurrent emission reduction of all the other regulated pollutants because they are being reduced at no additional cost. While this approach assigns all costs to only a portion of the emission reduction and thus may overstate the cost for that assigned portion, it does not overstate the overall cost. Instead, it acknowledges that the reductions of the other regulated pollutant are intended as opposed to incidental. This approach is simple and straightforward in application: If the multipollutant control is cost effective for reducing emissions of either of the targeted pollutants, it is clearly cost effective for reducing all other targeted emissions that are being achieved simultaneously.

A second approach, which we term for the purpose of this rulemaking a ''multipollutant cost-effectiveness approach,'' apportions the annualized cost across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. In the case of the Crude Oil and Natural Gas source category, both methane and VOC are reduced in equal proportions, relative to their respective baselines by the multipollutant control option (*i.e.,* where control is 95 percent reduction, methane and VOC are both simultaneously reduced by 95 percent by the multipollutant control). As a result, under the multipollutant cost-effectiveness approach, half of the control costs are allocated to methane and the other half to VOC. Under this approach, control is cost effective if it is cost effective for both VOC and methane.

We believe that both the single pollutant and multipollutant cost-effectiveness approaches discussed above are appropriate for assessing the reasonableness of the multipollutant controls considered in this action for new sources. As such, in the individual BSER analyses in section XII below, if a device is cost-effective under either of these two approaches, we find it to be cost-effective. The EPA has considered similar approaches in the past when considering multiple pollutants that are controlled by a given control option.[164] The EPA recognizes, however, not all situations where multipollutant controls are applied are the same, and that other types of approaches might be appropriate in other instances.

As mentioned above, as part of its consideration of control costs in the individual BSER analyses in Section XII, the EPA evaluated cost-effectiveness using the single pollutant and multipollutant cost-effectiveness approaches. We estimated the cost-effectiveness values of the proposed control options using available information, including various studies, information submitted in previous rulemakings from the affected industry, and information provided by small businesses. The EPA provides the cost effectiveness estimates for reducing VOC and methane emissions for various control options considered in section XII. As discussed in that section, the EPA finds cost-effectiveness values up to $5,540/ton of VOC reduction to be reasonable for controls that we have identified as BSER in this proposal. These VOC values are within the range of what the EPA has historically considered to represent cost effective controls for the reduction of VOC emissions, including in the 2016 NSPS, based on the Agency's long history of regulating a wide range of industries. With respect to methane, the EPA finds the cost-effectiveness values up to $1,800/ton of methane reduction to be reasonable for controls that we have identified as BSER in this proposal. Unlike VOC, the EPA does not have a long regulatory history to draw upon in assessing the cost effectiveness of controlling methane, as the 2016 NSPS OOOOa was the first national standard for reducing methane emissions. However, as explained below, the EPA has previously determined that methane cost-effectiveness values for the controls identified as BSER for the 2016 NSPS OOOOa, which range up to $2,185/ton of methane reduction, represent reasonable costs for the industry as a whole to bear; and because the cost-effectiveness estimates for the proposed standards in this action are comparable to the cost-effectiveness values estimated for the controls that served as the basis (*i.e.,* BSER) for the standards in the 2016 NSPS OOOOa, we consider the proposed standards to also be cost effective and reasonable.

The BSER determinations from the 2016 NSPS OOOOa also support the EPA's conclusion that the cost-effectiveness values associated with the proposed standards in this action are reasonable. As mentioned above, for 2016 NSPS OOOOa, the highest estimate that the EPA considered cost effective for methane reduction was $2,185/ton, which was the estimate for converting a natural gas driven diaphragm pump to an instrument air pump at a gas processing plant.[165] [166] 80 FR 56627; see also, NSPS OOOOa Final TSD at 93, Table 6–7. The EPA estimated that the cost-effectiveness of this option, a common practice at gas processing plants, could be up to $2,185/ton of methane reduction under the single pollutant cost-effectiveness approach and $1,093/ton under the multipollutant cost effectiveness approach; the EPA found ''the control to be cost effective under either approach.'' *Id.* Accordingly, the EPA finalized requirements in the 2016 NSPS OOOOa that require zero emissions from diaphragm pumps at gas processing plants, consistent with the Agency's BSER determination.

The 2016 NSPS OOOOa also requires 95 percent methane and VOC emission reduction from wet-seal centrifugal compressors. The BSER for this standard was capturing and routing the emissions to a control combustion device, a widely used control in the oil and gas sector for reducing emissions from storage vessels and pumps, in addition to centrifugal compressors. 80 FR 56620. The EPA estimated cost-effectiveness values of up to $1,093/ton of methane reduction for this option. *See* NSPS OOOOa Final TSD at 114, Table 7–9. With respect to other controls identified as BSER in the 2016 NSPS OOOOa, their cost-effectiveness estimates were comparable to or well below the estimates from the 2016 NSPS OOOOa rulemaking discussed above. In light of this, and because sources have been complying with the 2016 NSPS OOOOa for years, we believe that the cost-effectiveness values for the controls

[164] See, *e.g.,* 73 FR 64079–64083 and EPA Document I.D. EPA–HQ–OAR–2004–0022–0622, EPA–HQ–OAR–2004–0022–0447, EPA–HQ–OAR–2004–0022–0448.

[165] As discussed in section X.A, the EPA incorrectly stated in the 2020 Technical Rule that $738/ton of methane reduction was the highest cost-effectiveness value that the EPA determined to be reasonable for methane reduction in the 2016 NSPS OOOOa.

[166] While in that rulemaking the EPA found quarterly monitoring of fugitive emissions at well sites not cost effective at $1,960/ton of methane reduced using the single pollutant approach (and $980 using the multi-pollutant approach), the EPA emphasized that this conclusion was not intended to ''preclude the EPA from taking a different approach in the future including requiring more frequent monitoring *(e.g.,* quarterly).'' 81 FR 35855–6 referencing *Background Technical Support Document for the New Source Performance Standards 40 CFR part 60 subpart OOOOa* (May 2016), at 49, Table 4–11 and 52, Table 4–14. Further, several states have issued regulations and industry has voluntarily taken steps to reduce emissions. This combined with greater knowledge and understanding of the industry leads us to find these values cost-effective. As discussed in this section IX.B, cost-effectiveness is one—not the only—factor in EPA's consideration of control costs. In fact, in this action, the EPA is proposing different monitoring frequencies based on well site baseline emissions, even though the EPA found quarterly monitoring to be cost effective for all well sites. Please see section XII.A for a detailed discussion on this proposal.

identified as BSER for the 2016 NSPS OOOOa, which range up to $2,185/ton of methane reduction, represent reasonable, rather than excessive, costs for the industry as a whole to bear. As shown in the individual BSER analyses in Section XII and the NSPS OOOOb and EG OOOOc TSD for this proposal, the cost-effectiveness values for the proposed standards in this action are comparable to the cost-effectiveness values for the standards in NSPS OOOOa. We, therefore, similarly consider the cost-effectiveness values for the proposed standards to be reasonable. That the proposed standards reflect the kinds of controls that many companies and sources around the country are already implementing underscore the reasonableness of these control measures.

In addition to evaluating the annual average cost-effectiveness of a control option, the EPA also considers the incremental costs associated with increasing the stringency of the standards from one level of control to another level of control that achieves more emission reductions. The incremental cost of control provides insight into how much it costs to achieve the next increment of emission reductions through application of each increasingly stringent control options, and thus is a useful tool for distinguishing among the effects of more and less stringent control options. For example, during the rulemaking for the 2012 NSPS OOOO, the EPA considered the incremental cost effectiveness of changing the originally promulgated standards for leaks at gas processing plants, which were based on NSPS subpart VV, to the more stringent NSPS subpart VVa-level program. See 76 FR 52738, 52755 (August 23, 2011). The EPA generally finds the incremental cost-effectiveness to be reasonable if it is consistent with the costs that the Agency considers reasonable in its evaluation of annual average cost-effectiveness.

As shown in the NSPS OOOOb and EG OOOOc TSD for this action, the EPA estimated control costs both with and without savings from recovered gas that would otherwise be emitted. When determining the overall costs of implementation of the control technology and the associated cost-effectiveness, the EPA reasonably takes into account any expected revenues from the sale of natural gas product that would be realized as a result of avoided emissions that result from implementation of a control. Such a sale would offset regulatory costs and so should be included to accurately assess the overall costs and the cost-effectiveness of the standard. In our analysis we consider any natural gas that is either recovered or that is not emitted as a result of a control option as being ''saved.'' We estimate that one thousand standard cubic feet (Mcf) of natural gas is valued at $3.13 per Mcf.[167] Our cost analysis then applies the monetary value of the saved natural gas as an offset to the control cost.[168] This offset applies where, in our estimation, the monetary savings of the natural gas saved can be realized by the affected facility owner or operator and not where the owner or operator does not own the gas and would not likely realize the monetary value of the natural gas saved (*e.g.,* transmission stations and storage facilities). Detailed discussions of these assumptions are presented in section 2 of the RIA associated with this action, which is in the docket.

We also completed two additional analyses to further inform our determination of whether the cost of control is reasonable, similar to compliance cost analyses we have completed for other NSPS.[169] First, we compared the capital costs that would be incurred to comply with the proposed standards to the industry's estimated new annual capital expenditures. This analysis allowed us to compare the capital costs that would be incurred to comply with the proposed standards to the level of new capital expenditures that the industry is incurring in the absence of the proposed standards. We then determined whether the capital costs appear reasonable in comparison to the industry's current level of capital spending. Second, we compared the annualized costs that would be incurred to comply with the standards to the industry's estimated annual revenues. This analysis allowed us to evaluate the annualized costs as a percentage of the revenues being generated by the industry.

The EPA has evaluated incremental capital costs in a manner similar to the analyses described above in prior new source performance standards, and in those prior standards, the Agency's determinations that the costs were reasonable were upheld by the courts. For example, the EPA estimated that the costs for the 1971 NSPS for coal-fired electric utility generating units were $19 million for a 600 MW plant, consisting of $3.6 million for particulate matter controls, $14.4 million for sulfur dioxide controls, and $1 million for nitrogen oxides controls, representing a total 15.8 percent increase in capital costs above the $120 million cost of the plant.[170] *See* 1972 Supplemental Statement, 37 FR 5767, 5769 (March 21, 1972). The D.C. Circuit upheld the EPA's determination that the costs associated with the final 1971 standard were reasonable, concluding that the EPA had properly taken costs into consideration. *Essex Chemical,* 486 F. 2d at 440. Similarly, in *Portland Cement Association* v. *Ruckelshaus,* the D.C. Circuit upheld the EPA's consideration of costs for a standard of performance that would increase capital costs by about 12 percent, although the rule was remanded due to an unrelated procedural issue. 486 F.2d 375, 387–88 (D.C. Cir. 1973). Reviewing the EPA's final rule after remand, the court again upheld the standards and the EPA's consideration of costs, noting that ''[t]he industry has not shown inability to adjust itself in a healthy economic fashion to the end sought by the Act as represented by the standards prescribed.'' *Portland Cement Assn.* v. *Train,* 513 F. 2d at 508.

In this action, for the capital expenditures analysis, we divide 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 $510 million in 2019 dollars. We obtained new capital

[167] This value reflects the forecasted Henry Hub price for 2022 from: U.S. Energy Information Administration. Short-Term Energy Outlook. *https://www.eia.gov/outlooks/steo/archives/may21.pdf.* Release Date: May 11, 2021.

[168] While the EPA presents cost-effectiveness with and without cost savings, the BSER is determined based on the cost-effectiveness without cost savings in all cases.

[169] 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.

[170] Assuming these costs were denominated in 1971 dollars, converting the costs from 1971 to 2019 dollars using the Gross Domestic Product-Implicit Price Deflator, the costs for the 1971 NSPS for coal-fired electric utility generating units were $94 million for a 600 MW plant, consisting of $18 million for particulate matter controls, $71 million for sulfur dioxide controls, and $5 million for nitrogen oxides controls, representing a 15.8 percent increase in capital costs above the $590 million cost of the plant.

expenditure data for relevant NAICS codes for 2018 from the U.S. Census 2019 Annual Capital Expenditures Survey.[171] Estimates of new capital expenditures are available for 2019, but we chose to use 2018 because the 2019 new capital expenditure data for pipeline transportation of natural gas (NAICS 4862) are withheld to avoid disclosing data for individual enterprises, and the withholding of that NAICS causes the totals for 2019 to be lower than for 2018. According to these data, new capital expenditures for the sector in 2018 were about $155 billion in 2019 dollars. Comparing the EAV of the projected compliance-related capital expenditures under the proposal with the 2018 total sector-level new capital expenditures yields a percentage of about 0.3 percent, which is well below the percentage increase previously upheld by the courts, as discussed above.

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 $1.2 billion without revenues from product recovery and about $760 million 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.[172] According to these data, 2018 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 0.3 percent without revenues from product recovery and about 0.2 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 Chapter 15 of 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. The EPA also performed two broad comparisons to consider the costs of control: First, we compared the projected compliance-related capital expenditures to recent sector-level capital expenditures; second, we compared the projected total compliance costs to recent sector-level annual revenues. 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. 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 above, 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.

X. Summary of Proposed Action for NSPS OOOOa

As described above in sections IV and VIII, the 2020 Policy Rule rescinded all NSPS regulating emissions of VOC and methane from sources in the natural gas transmission and storage segment of the Oil and Natural Gas Industry and NSPS regulating methane from sources in the industry's production and processing segments. As a result, the 2020 Technical Rule only amended the VOC standards for the production and processing segments in the 2016 NSPS OOOOa, because those were the only standards that remained at the time that the 2020 Technical Rule was finalized. The 2020 Technical Rule included amendments to address a range of technical and implementation issues in response to administrative petitions for reconsideration and other issues brought to the EPA's attention since promulgating the 2016 NSPS. These included, among other issues, those associated with the implementation of the fugitive emissions requirements and pneumatic pump standards, provisions to apply for the use of an AMEL, provisions for determining applicability of the storage vessel standards, and modification to the engineer certifications. In 2018, the EPA proposed amendments to address these technical issues for both the methane and VOC standards in the 2016 NSPS OOOOa, and in some instances for sources in the transmission and storage segment. 83 FR 52056, October 15, 2018. However, because the methane standards and all standards for the transmission and storage segment were removed via the 2020 Policy Rule prior to the finalization of the 2020 Technical Rule, the final amendments in the 2020 Technical Rule apply only to the 2016 NSPS OOOOa VOC standards for the production and processing segments. Additionally, the 2020 Policy Rule amended the 2012 NSPS OOOO to remove the VOC requirements for sources in the transmission and storage segment, but the Technical Rule did not amend the 2012 NSPS OOOO.

Under the CRA, a rule that is subject to a joint resolution of disapproval ''shall be treated as though such rule had never taken effect.'' 5 U.S.C. 801(f)(2). Thus, because it was disapproved under the CRA, the 2020 Policy Rule is treated as never having taken effect. As a result, the requirements in the 2012 NSPS OOOO and 2016 NSPS OOOOa that the 2020 Policy Rule repealed (*i.e.,* the VOC and methane standards for the transmission and storage segment, as well as the methane standards for the production and processing segments) must be treated as being in effect immediately upon enactment of the joint resolution on June 30, 2021. Any new, reconstructed, or modified facility that would have been subject to the 2012 or 2016 NSPS (''affected facility'') but for the 2020 Policy Rule was subject to those NSPS as of that date. The CRA resolution did not address the 2020 Technical Rule; therefore, the amendments made in the 2020 Technical Rule, which apply only to the VOC standards for the production and processing segments in the 2016 NSPS OOOOa, remain in effect. As a result, sources in the production and processing segments are now subject to two different sets of standards:[173] One

[171] U.S. Census Bureau, 2019 Annual Capital Expenditures Survey, Table 4b. Capital Expenditures for Structures and Equipment for Companies With Employees by Industry: 2018 Revised, *http://www.census.gov/econ/aces/index.html,* accessed September 4, 2021.

[172] 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.

[173] The only exception is storage vessels, for which the EPA did not promulgate methane standards in the 2016 NSPS OOOOa.

for methane based on the 2016 NSPS OOOOa, and one for VOC that include the amendments to the 2016 NSPS OOOOa made in the 2020 Technical Rule. Sources in the transmission and storage segment are subject to the methane and VOC standards as promulgated in either the 2012 NSPS OOOO or the 2016 NSPS OOOOa, as applicable.[174] The EPA recognizes that certain amendments made to the VOC standards in the 2016 NSPS OOOOa in the 2020 Technical Rule, which addressed technical and implementation issues in response to administrative petitions for reconsideration and other issues brought to the EPA's attention since promulgating the 2016 NSPS OOOOa rule could also be appropriate to address similar implementation issues associated with the methane standards for the production and processing segments and the methane and VOC standards for the transmission and storage segment. In fact, as mentioned above, such revisions were proposed in 2018 but not finalized because these standards were removed by the 2020 Policy Rule prior to the EPA's promulgation of the 2020 Technical Rule. In light of the above, the EPA is proposing to revise 40 CFR part 60, subpart OOOOa, to apply certain amendments made in the 2020 Technical Rule to the 2016 NSPS OOOOa for methane from the production and processing segments and/or the 2016 NSPS OOOOa for methane and VOC from the transmission and storage segment, as specified in this section.

In this action, the EPA is proposing amendments to the 2016 NSPS OOOOa to (1) rescind the revisions to the VOC fugitive emissions monitoring frequencies at well sites and gathering and boosting compressor stations in the 2020 Technical Rule as those revisions were not supported by the record for that rule, or by our subsequent information and analysis, and (2) adjust other modifications made in the 2020 Technical Rule to address technical and implementation issues that result from the CRA disapproval of the 2020 Policy Rule. The EPA is not reopening any of these prior rulemakings for any other purpose in this proposed action. Specifically, the EPA is not reopening any of the determinations made in the 2012 NSPS OOOO. In the final rule for this action, the EPA will update the NSPS OOOO and NSPS OOOOa regulatory text in the CFR to reflect the CRA resolution's disapproval of the final 2020 Policy Rule, specifically, the reinstatement of the NSPS OOOO and NSPS OOOOa requirements that the 2020 Policy Rule repealed but that came back into effect immediately upon enactment of the CRA resolution. In accordance with 5 U.S.C. 553(b)(3)(B), the EPA is not soliciting comment on these updates. Moreover, the EPA is not reopening the methane standards as finalized in the 2016 NSPS OOOOa, except as to the specific issues discussed below, nor is the EPA reopening any other portions of the 2016 Rule. The EPA is also not reopening any determinations made in the 2020 Technical Rule, except as to the specific issues discussed below. Finally, the reopening of determinations made with respect to the VOC standards in the 2020 Technical Rule does not indicate any intent to also reopen the methane standards for the same affected facilities.

A. Amendments to Fugitive Emissions Monitoring Frequency

The EPA is proposing to repeal its amendments in the 2020 Technical Rule that (1) exempted low production well sites from monitoring fugitive emissions and (2) changed from quarterly to semiannual monitoring of VOC emissions at gathering and boosting compressor stations. The EPA has authority to reconsider a prior action "as long as 'the new policy is permissible under the statute. . . , there are good reasons for it, and . . . the agency *believes* it to be better.' " *FCC* v. *Fox Television Stations, Inc., 556 U.S. 502, 515, 129 S. Ct. 1800, 173 L. Ed. 2d738 (2009).*

The 2016 NSPS OOOOa, as initially promulgated, required semiannual monitoring of VOC and methane emissions at all well sites, including low production well sites. It also required quarterly monitoring of compressor stations, including gathering and boosting compressor stations. After issuing the 2020 Policy Rule, which removed all methane standards applicable to the production and processing segments and all methane and VOC standards applicable to the transmission and storage segment, the EPA promulgated the 2020 Technical Rule that further amended the VOC standards in the production and processing segment. In particular, based on its revised cost analyses, the EPA exempted low production well sites from monitoring VOC fugitive emissions and changed the frequency of monitoring VOC fugitive emissions from quarterly to semiannually at gathering and boosting compressor stations. However, as a result of the CRA disapproval of the 2020 Policy Rule, the low production well sites and the gathering and boosting compressor stations continue to be subject to semiannual and quarterly monitoring of methane emissions respectively. While it is possible for these affected facilities to comply with both the VOC and methane monitoring standards that are now in effect, as compliance with the more stringent standard would be deemed compliance with the other, the EPA reviewed its decisions to amend the VOC monitoring frequencies for these affected facilities as well as the underlying record and, for the reasons explained below, no longer believe that the amendments are appropriate. Therefore, the EPA is proposing to repeal these amendments and restore the semiannual and quarterly monitoring requirements for low production well sites and gathering and boosting compressor stations, as originally promulgated in the 2016 NSPS OOOOa, for both methane and VOC.

1. Low Production Well Sites

As mentioned above, low production well sites are subject to semiannual monitoring of fugitive methane emissions. The EPA is proposing to repeal the amendment in the 2020 Technical Rule exempting low production well sites from monitoring fugitive VOC emissions because the analysis for the 2020 Technical Rule supports retaining the semiannual monitoring requirement when regulating both VOC and methane emissions. While the 2020 Technical Rule amended only the VOC standards in the production and processing segments, the EPA evaluated both methane and VOC reductions in its final technical support document (TSD) (2020 TSD), including the costs associated with different monitoring frequencies under the multipollutant approach,[175] which the EPA considers a reasonable approach when regulating multiple pollutants. As shown in the 2020 TSD, under the multipollutant approach, the cost of semiannual monitoring at low production well sites is $850 per ton of methane and $3,058 per ton of VOC reduced, both of which are well within the range of what the

[174] For the EPA's full explanation of its initial guidance to stakeholders on the impact of the CRA, please see *https://www.epa.gov/system/files/documents/2021-07/qa_cra_for_2020_oil_and_gas_policy_rule.6.30.2021.pdf.*

[175] For purposes of the multipollutant approach, we assume that emissions of methane and VOC are controlled at the same time, therefore, half of the cost is apportioned to the methane emission reductions and half of the cost is apportioned to VOC emission reductions.

EPA considers to be cost effective.[176] Nevertheless, the EPA stated in the 2020 Technical Rule that ''even if we had not rescinded the methane standards in the 2020 Policy Rule, we would still conclude that fugitive emissions monitoring, at any of the frequencies evaluated, is not cost effective for low production well sites.'' This statement, however, is inconsistent with the conclusions on what costs are reasonable for the control of methane emissions as discussed in this proposal in section IX. More importantly, as an initial matter, this statement was based on the EPA's observation in the 2020 Technical Rule that the $850 per ton of methane reduced is ''greater than the highest value for methane that the EPA determined to be reasonable in the 2016 NSPS subpart OOOOa,'' which the EPA incorrectly identified as $738/ton; the record for the 2016 NSPS OOOOa shows that the EPA considered value as high as $2,185/ton to be cost effective for methane reduction. 80 FR 56627; see also, NSPS OOOOa Final TSD at 93, Table 6–7. Further, even with the incorrect observation, the EPA did not conclude in the 2020 Technical Rule that $850 per ton of methane reduced is therefore unreasonable. 85 FR 57420. In fact, the EPA reiterated its prior determination that ''a cost of control of $738 per ton of methane reduced did not appear excessive,'' and that value was only $112 less than the value that the EPA had incorrectly identified as the highest methane cost-effectiveness value from the 2016 NSPS OOOOa. As discussed above, in fact $738/ton is well within the costs that the EPA concludes to be reasonable in the 2016 NSPS OOOOa as well as in this document. Also, as explained in section XI.A.2, due to the wide variation in well characteristics, types of oil and gas products and production levels, gas composition, and types of equipment at well sites, there is considerable uncertainty regarding the relationship between the fugitive emissions and production levels. Accordingly, the EPA no longer believes that production levels provide an appropriate threshold for any exemption from fugitive monitoring. See section XI.A.2 for additional discussion on the proposed emission thresholds for well site fugitive emissions in place of production-based model plants. In light of the above, the EPA is proposing to remove the exemption of low production well sites from fugitive VOC emissions monitoring, thereby restoring the semiannual monitoring requirement established in the 2016 NSPS OOOOa.

2. Gathering and Boosting Compressor Stations

The EPA is proposing to repeal its amendment to the VOC monitoring frequency for gathering and boosting compressor stations in the 2020 Technical Rule because the EPA believes that amendment was made in error. In that rule, the EPA noted that, based on its revised cost analysis, quarterly monitoring has a cost effectiveness of $3,221/ton of VOC emissions and an incremental cost of $4,988/ton of additional VOC emissions reduced between the semiannual and quarterly monitoring frequencies. While the EPA observed that semiannual monitoring is more cost effective than quarterly, the EPA nevertheless acknowledged that ''these values (total and incremental) are considered cost-effective for VOC reduction based on past EPA decisions, including the 2016 rulemaking.'' 85 FR 57421, September 15, 2020. The EPA instead identified two additional factors to support its decision to forgo quarterly monitoring. First, the EPA stated that the ''Oil and Gas Industry is currently experiencing significant financial hardship that may weigh against the appropriateness of imposing the additional costs associated with more frequent monitoring.'' However, the EPA did not offer any data regarding the financial hardship, significant or otherwise, the industry was experiencing. While the rule cited to several articles on the impact of COVID–19 on the industry, the EPA did not discuss any aspect of any of the cited articles that led to its conclusion of ''significant financial hardship'' on the industry. Nor did the EPA explain how reducing the frequency of a monitoring requirement that had been in effect since 2016 would meaningfully affect the industry's economic circumstances in any way or weigh those considerations against the forgone emission reductions that would result from reducing monitoring frequency.

Second, the EPA generally asserted that ''there are potential efficiencies, and potential cost savings, with applying the same monitoring frequencies for well sites and compressor stations.'' Again, the EPA did not describe what the potential efficiencies are or the extent of cost savings that would justify forgoing quarterly monitoring, or weigh those efficiencies and cost savings against the forgone emission reductions that would result from reducing the monitoring frequency for compressor stations. Nor did we explain why the Agency's 2016 BSER determination that quarterly monitoring was achievable and cost-effective was incorrect in light of these asserted efficiencies. On the contrary, based on the compliance records for the 2016 NSPS OOOOa, there is no indication that compressor stations experienced hardship or difficulty in complying with the quarterly monitoring requirement. Further, as discussed in section XII.A.1.b, our analysis for NSPS OOOOb and EG OOOOc confirms that quarterly monitoring remains both achievable and cost-effective for compressor stations, and several State agencies also have rules that require quarterly monitoring at compressor stations. For the reasons stated above, the EPA concludes that it lacked justification and thus erred in revising the VOC monitoring frequency for gathering and boosting compressor stations from quarterly to semiannual. The EPA is therefore proposing to repeal that amendment, thereby restoring the quarterly monitoring requirement for gathering and boosting compressor stations, as established in the 2016 NSPS OOOOa.

B. Technical and Implementation Amendments

In the following sections, the EPA describes a series of proposed amendments to 2016 NSPS OOOOa for methane to align the 2016 methane standards with the current VOC standards (which were modified by the 2020 Technical Rule). We describe the supporting rationales that were provided in the 2020 Technical Rule for modifying the requirements applicable to the VOC standards, and explain why the amendments would also appropriately apply to the reinstated methane standards.

1. Well Completions

In the 2020 Technical Rule, the EPA made certain amendments to the VOC standards for well completions in the 2016 NSPS OOOOa. For the same reasons provided in the 2020 Technical Rule and reiterated below, the EPA is proposing to apply the same amendments to the methane standards for well completions in the 2016 NSPS OOOOa.

First, the EPA is proposing to amend the 2016 NSPS OOOOa methane standards for well completions to allow

[176] See 2020 NSPS OOOOa Technical Rule TSD at Docket ID No. EPA–HQ–OAR–2017–0483–2291. See also section IX, which provides that the cost effectiveness values for the controls that we have identified as BSER in this action range from $2,200/ton to $5,800/ton VOC reduction and $700/ton to $2,100/ton of methane reduction. As explained in that section, these controls reflect emission reduction technologies and methods that many owners and operators in the oil and gas industry have employed for years, either voluntarily or due to the 2012 and 2016 NSPS, as well as State or other requirements.

the use of a separator at a nearby centralized facility or well pad that services the well affected facility during flowback, as long as the separator can be utilized as soon as it is technically feasible for the separator to function. The well completion requirements, as promulgated in 2016, had required that the owner or operator of a well affected facility have a separator on site during the entire flowback period. 81 FR 35901, June 3, 2016. In the 2020 Technical Rule, the EPA amended this provision to allow the separator to be at a nearby centralized facility or well pad that services the well affected facility during flowback as long as the separator can be utilized as soon as it is technically feasible for the separator to function. See 40 CFR 60.5375a(a)(1)(iii). As explained in that rulemaking (85 FR 57403) and previously in the 2016 NSPS OOOOa final rule preamble, ''[w]e anticipate a subcategory 1 well to be producing or near other producing wells. We therefore anticipate reduced emission completion (REC) equipment (including separators) to be onsite or nearby, or that any separator brought onsite or nearby can be put to use.'' 81 FR 35852, June 3, 2016. For the same reason, the EPA is proposing to make the same amendment to the methane standards for well completions.

Additionally, the 2020 Technical Rule amended 40 CFR 60.5375a(a)(1)(i) to clarify that the separator that is required during the initial flowback stage may be a production separator as long as it is also designed to accommodate flowback. As explained in the preamble to the final 2020 Technical Rule, when a production separator is used for both well completions and production, the production separator is connected at the onset of the flowback and stays on after flowback and at the startup of production. 85 FR 57403, September 15, 2020. For the same reason, the EPA is proposing the same clarification apply to the methane standards for well completions.

The 2020 Technical Rule also amended the definition of flowback. In 2016, the EPA defined ''flowback'' as the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. Flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage. 81 FR 35934, June 3, 2016.

The 2020 Technical Rule amended this definition by adding a clarifying statement that ''[s]creenouts, coil tubing cleanouts, and plug drill-outs are not considered part of the flowback process.'' 40 CFR 60.5430a. In the proposal for the 2020 Technical Rule, the EPA explained that screenouts, coil tubing cleanouts, and plug drill outs are functional processes that allow for flowback to begin; as such, they are not part of the flowback. 83 FR 52082, October 15, 2018. In conjunction with this amendment, the 2020 Technical Rule added definitions for screenouts, coil tubing cleanouts, and plug drill outs. See 40 CFR 60.5430a. Specifically, a screenout is an attempt to clear proppant from the wellbore in order to dislodge the proppant out of the well. A coil tubing cleanout is a process where an operator runs a string of coil tubing to the packed proppant within a well and jets the well to dislodge the proppant and provide sufficient lift energy to flow it to the surface. A plug drill-out is the removal of a plug (or plugs) that was used to isolate different sections of the well. For the reason stated above, the EPA is proposing to apply the definitions of flowback, screenouts, coil tubing cleanouts, and plug drill outs that were finalized in the 2020 Technical Rule to the methane standards for well completions in the 2016 NSPS OOOOa.

Finally, the 2020 Technical Rule amended specific recordkeeping and reporting requirements for the VOC standards for well completions, and the EPA is proposing to apply these amendments to the methane standards for well completions in the 2016 NSPS OOOOa. For the reasons explained in 83 FR 52082, the 2020 Technical Rule requires that for each well site affected facility that routes flowback entirely through one or more production separators, owners and operators must record and report only the following data elements:

- Well Completion ID;
- Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983;
- U.S. Well ID;
- The date and time of the onset of flowback following hydraulic fracturing or refracturing or identification that the well immediately starts production; and
- The date and time of the startup of production.

While the 2020 Technical Rule removed certain reporting requirements (*e.g.,* information about when a separator is hooked up or disconnected during flowback) as unnecessary or redundant, 85 FR 57403, the rule added a requirement that for periods where salable gas is unable to be separated, owners and operators must record and report the date and time of onset of flowback, the duration and disposition of recovery, the duration of combustion and venting (if applicable), reasons for venting (if applicable), and deviations.

As explained in the preamble to the proposal for the 2020 Technical Rule, when a production separator is used for both well completions and production, the production separator is connected at the onset of the flowback and stays on after flowback and at the startup of production; in that event, certain reporting and recordkeeping requirements associated with well completions (*e.g.,* information about when a separator is hooked up or disconnected during flowback) would be unnecessary. 83 FR 52082. Because these amendments to the recordkeeping and reporting requirements associated with well completion are independent of the specific pollutant being regulated, we are proposing these same amendments to the methane standards for well completions in the 2016 NSPS OOOOa.

2. Pneumatic Pumps

In the 2020 Technical Rule, the EPA made certain amendments to the VOC standards for pneumatic pumps in the 2016 NSPS OOOOa. For the same reasons provided in the 2020 Technical Rule, along with further explanation provided below, the EPA is proposing to apply the same amendments to the methane standards for pneumatic pumps in the 2016 NSPS OOOOa.

First, the EPA is proposing to amend the 2016 NSPS OOOOa methane standards for pneumatic pumps to expand the technical infeasibility provision to apply to pneumatic pumps at greenfield sites. Under the 2016 NSPS OOOOa, ''emissions from new, modified, and reconstructed natural gas-driven diaphragm pumps located at well sites [must] be reduced by 95 percent if either a control device or the ability to route to a process is already available onsite, unless it is technically infeasible at sites other than new developments (*i.e.,* greenfield sites).'' 81 FR 35824 and 35844. For the 2016 NSPS OOOOa, the EPA concluded that circumstances that could otherwise make control of a pneumatic pump technically infeasible at an existing location could be addressed in the design and construction of a greenfield site. 81 FR 35849 and 35850 (June 3, 2016). Concerns raised in petitions for reconsideration on the 2016 NSPS OOOOa explained that, even at greenfield sites, certain scenarios present circumstances where the control of a pneumatic pump may be technically infeasible despite the site being newly designed and constructed.[177] These circumstances include, but are not limited to, site designs requiring high-pressure flares to which routing a low-pressure pump discharge is not feasible and use of small boilers or process heaters that are insufficient to control pneumatic pump emissions or that could result in safety trips and burner flame instability. The EPA proposed to extend the technical infeasibility exemption to greenfield sites in 2018 and sought comment on these circumstances that could preclude control of a pneumatic pump at greenfield sites. While the EPA received comments both in favor of and opposing the application of the technical infeasibility exemption to greenfield sites, the commenters did not identify a reasoned basis for the EPA to decline to extend the exemption. See Response to Comments (RTC) for 2020 Technical Rule at 5–1 to 5–4 at Docket ID No. EPA–HQ–OAR–2017–0483. Moreover, the EPA specifically sought information regarding the additional costs that would be incurred if owners and operators of greenfield sites were required to select a control that can accommodate pneumatic pump emissions in addition to the control's primary purpose at a new construction site, but no such information was provided.

The 2020 Technical Rule therefore expanded the technical infeasibility provision to apply to pneumatic pumps at all well sites, including new developments (greenfield sites), concluding that the extension was appropriate because the EPA identified circumstances where it may not be technically feasible to control pneumatic pumps at a greenfield site. The 2020 Technical Rule removed the reference to greenfield site in 40 CFR 60.5393a(b) and the associated definition of greenfield site at 40 CFR 60.5430a.

In the final rule preamble for the 2016 NSPS OOOOa, the EPA stated we did not intend to require the installation of a control device at a well site for the sole purpose of controlling emissions from a pneumatic pump, but rather only required control of pneumatic pumps to the extent a control device or process would already be available on site. It is not the EPA's intent to require a greenfield site to install a control device specifically for controlling emissions from a pneumatic pump. It is our understanding that sites are designed to maximize operation and safety. This includes the placement of equipment, such as control devices. Because vented gas from pneumatic pumps is at low pressure, it may not be feasible to move collected gas through a closed vent system to a control device, depending on site design. Therefore, the EPA continues to conclude that, when determining technical feasibility at any site, such a determination should consider the routing of pneumatic pump emissions to the controls which are needed for the other processes at the site (*i.e.,* not the pneumatic pump). The owner or operator must justify and provide professional or in-house engineering certification for any site where the control of pneumatic pump emissions is technically infeasible. As explained in the RTC for the 2020 Technical Rule, ''[t]he EPA believes that the requirement to certify an engineering assessment to demonstrate technical infeasibility provides protection against an owner or operator purposely designing a new site just to avoid routing emissions from a pneumatic pump to an onsite control device or to a process.'' [178] For the reasons explained above, the EPA is proposing to align the methane standards in the 2016 NSPS OOOOa for controlling pneumatic pump emissions with the amendments made to the VOC standards in the 2020 Technical Rule to allow for a well-justified determination of technical infeasibility at all well sites, including greenfield sites.

Second, the 2020 Technical Rule amended the 2016 NSPS OOOOa to specify that boilers and process heaters are not considered control devices for the purposes of the pneumatic pump standards. It is the EPA's understanding, based on information provided in reconsideration petitions [179] submitted regarding the 2016 NSPS OOOOa and comments received on the proposal for the 2020 Technical Rule, that some boilers and process heaters located at well sites are not inherently designed for the control of emissions. While it is true that for some other sources (not pneumatic pumps), boilers and process heaters may be designed as control devices, that is generally not the operational purpose of this equipment at a well site. Instead, it is the EPA's understanding that boilers and process heaters operate seasonally, episodically, or otherwise intermittently as process devices, thus making the use of these devices as controls inefficient and non-compliant with the continuous control requirements at 40 CFR 60.5415a.[180] Further, as explained in the 2020 Technical Rule, the fact that some boilers and process heaters located at well sites are not inherently designed to control emissions means that ''routing pneumatic pump emissions to these devices may result in frequent safety trips and burner flame instability (*e.g.,* high temperature limit shutdowns and loss of flame signal).'' *Id.* The EPA determined that ''requiring the technical infeasibility evaluation for every boiler and process heater located at a wellsite would result in unnecessary administrative burden since each such evaluation would be raising the[se] same concerns.'' 85 FR 57404 (September 15, 2020). Further, as described above, the EPA did not intend to require the installation of a control device for the sole purpose of controlling emissions from pneumatic pumps. Based on the EPA's understanding that boilers and process heaters located at well sites are designed and operated as process equipment (meaning they are not inherently designed for the control of emissions), the EPA also does not intend to require their continuous operation solely to control emissions from pneumatic pumps either. Therefore, the EPA is proposing to align the methane standards for pneumatic pumps with the 2020 Technical Rule to specify that boilers and process heaters are not considered control devices for the purposes of controlling pneumatic pump emissions. The EPA solicits comment on this alignment, including whether there are specific examples where boilers and process heaters are

[177] See proposal for 2020 Technical Rule at 83 FR 52061.

[178] See Docket ID No. EPA–HQ–OAR–2017–0483–2291. ''For example, consider the example provided by one commenter where a new site design requires only a high-pressure flare to control emergency and maintenance blowdowns and it is not feasible for a low-pressure pneumatic pump discharge to be routed to such a flare. The infeasibility determination would need not only demonstrate that it is not feasible for a low-pressure pneumatic pump discharge to be directly routed to the flare, it would also need to demonstrate that it is infeasible to design and install a low-pressure header to allow routing this discharge to such a flare system.'' RTC at 5–4.

[179] See Docket ID No. EPA–HQ–OAR–2017–0483–0016.

[180] See Docket ID No. EPA–HQ–OAR–2017–0483–0016.

currently used as control devices at well sites.

Third, the EPA is proposing to align the certification requirements for the determination that it is technically infeasible to route emissions from a pneumatic pump to a control device or process. The 2016 NSPS OOOOa required certification of technical infeasibility by a qualified third-party Professional Engineer (PE); however, the 2020 Technical Rule allows this certification by either a PE or an in-house engineer, because in-house engineers may be more knowledgeable about site design and control than a third-party PE. The EPA continues to believe that certification by an in-house engineer is appropriate for this purpose. We are, therefore, proposing to align the methane standards in the 2016 NSPS OOOOa with the 2020 Technical Rule to allow certification of technical infeasibility by either a PE or an in-house engineer with expertise on the design and operation of the pneumatic pump. We are soliciting comment on this proposed alignment.

3. Closed Vent Systems (CVS)

As in the 2020 Technical Rule, the EPA is proposing to allow multiple options for demonstrating that there are no detectable methane emissions from CVS. Additionally, the EPA is proposing to allow either a PE or an in-house engineer with expertise on the design and operation of the CVS to certify the design and operation will meet the requirement to route all vapors to the control device or back to the process.

The methane standards in the 2016 NSPS OOOOa require that CVS be operated with no detectable emissions, as demonstrated through specific monitoring requirements associated with the specific affected facilities (*i.e.,* pneumatic pumps, centrifugal compressors, reciprocating compressors, and storage vessels). Relevant here, the 2016 NSPS OOOOa required this demonstration for both VOC and methane emissions through annual inspections using EPA Method 21 for CVS associated with pneumatic pumps, while requiring storage vessels to conduct monthly audio, visual, olfactory (AVO) monitoring. The 2020 Technical Rule amended the VOC requirements for CVS for pneumatic pumps to align the requirements for pneumatic pumps and storage vessels by incorporating provisions allowing the option to demonstrate the pneumatic pump CVS is operated with no detectable emissions by either an annual inspection using EPA Method 21, monthly AVO monitoring, or OGI monitoring at the frequencies specified for fugitive emissions monitoring. The EPA is proposing to amend the methane standards to allow pneumatic pump affected facilities to permit these same options to demonstrate no detectable methane emissions from CVS either using annual Method 21 monitoring, as currently required by the 2016 NSPS OOOOa, or using either monthly AVO monitoring or OGI monitoring at the fugitive monitoring frequency. The EPA considers these detection options appropriate for CVS associated with pneumatic pumps because any of the three would detect methane as well as VOC emissions. We incorporated the option for monthly AVO monitoring in the 2020 Technical Rule because pneumatic pumps and controlled storage vessels are commonly located at the same site and having separate monitoring requirements for a potentially shared CVS is overly burdensome and duplicative. 83 FR 52083 (October 15, 2018). We further incorporated the option for OGI monitoring because OGI is already being used for those sites that are subject to fugitive emissions monitoring and the CVS can readily be monitored during the fugitive emissions survey at no extra cost. 85 FR 57405. The EPA believes it is appropriate to maintain these options because not all well sites with controlled pneumatic pumps will be subject to fugitive emissions monitoring (*e.g.,* pneumatic pumps located at existing well sites that have not triggered the fugitive monitoring requirements for new or modified well sites) and requiring either OGI or EPA Method 21 survey of the CVS for the pneumatic pump in the absence of fugitive emissions surveys would be unreasonable. It is possible for a new pneumatic pump to be subject to control at an existing well site that is not subject to the fugitive emissions requirements. Requiring either EPA Method 21 or OGI for the sole purpose of monitoring the CVS associated with the pneumatic pump would be too costly,[181] therefore we continue to believe monthly AVO is an appropriate option for pneumatic pumps subject to the 2016 NSPS OOOOa.

Additionally, the 2020 Technical Rule amended the 2016 NSPS OOOOa to allow certification of the design and operation of CVS by an in-house engineer with expertise on the design and operation of the CVS in lieu of a PE. This certification is necessary to ensure the design and operation of the CVS will meet the requirement to route all vapors to the control device or back to the process. As explained in the proposal for the 2020 Technical Rule, 83 FR 52079, the EPA allows CVS certification by either a PE or an in-house engineer because in-house engineers may be more knowledgeable about site design and control than a third-party PE. For the same reason, the EPA is proposing to amend the CVS requirements associated with methane emissions in the production and processing segments, and methane and VOC emissions in the transmission and storage segment, to allow certification of the design and operation of CVS by either a PE or an in-house engineer with expertise on the design and operation of the CVS.

4. Fugitive Emissions at Well Sites and Compressor Stations

a. Well Sites

The EPA is proposing to exclude from fugitive emissions monitoring a well site that is or later becomes a ''wellhead only well site,'' which the 2020 Technical Rule defines as ''a well site that contains one or more wellheads and no major production and processing equipment.'' The 2016 NSPS OOOOa excludes well sites that contain only one or more wellheads from the fugitive emissions requirements because fugitive emissions at such well sites are extremely low. 80 FR 56611. As explained in that rulemaking, ''[s]ome well sites, especially in areas with very dry gas or where centralized gathering facilities are used, consist only of one or more wellheads, or 'Christmas trees,' and have no ancillary equipment such as storage vessels, closed vent systems, control devices, compressors, separators and pneumatic controllers. Because the magnitude of fugitive emissions depends on how many of each type of component (*e.g.,* valves, connectors, and pumps) are present, fugitive emissions from these well sites are extremely low.'' 80 FR 56611. The 2020 Technical Rule amended the 2016 NSPS OOOOa to exclude from fugitive emissions monitoring a well site that is or later becomes a ''wellhead only well site,'' which the 2020 Technical Rule defines as ''a well site that contains one or more wellheads and no major production and processing equipment.'' The 2020 Technical Rule defined ''major production and processing equipment''

[181] Both OGI and EPA Method 21 have significant capital and annual costs, including the cost of specialized equipment and trained operators of that equipment. While the costs of these programs are justified for well site fugitive emission monitoring based on the assumption of a high component count from which emissions would be controlled, the CVS is only one of those many components. Thus, where well site fugitive monitoring is not otherwise required, the cost-effectiveness of OGI or EPA Method 21 would be significantly higher for the CVS alone.

as including reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water. We continue to believe that available information, including various studies,[182] supports an exemption for well sites that do not have this major production and processing equipment. The 2020 Technical Rule allows certain small ancillary equipment, such as chemical injection pumps, pneumatic controllers used to control well emergency shutdown valves, and pumpjacks, that are associated with, or attached to, the wellhead and ''Christmas tree'' to remain at a ''wellhead only well site'' without being subject to the fugitive emissions monitoring requirements because they have very few fugitive emissions components that would leak, and therefore have limited potential for fugitive emissions. The emission reduction benefits of continuing monitoring at that point would be relatively low, and thus would not be cost-effective.

For the reason stated above, the EPA is proposing to amend the 2016 NSPS OOOOa to allow monitoring of methane fugitive emissions to stop when a wellsite contains only wellhead(s) and no major production and processing equipment, as provided in the 2020 Technical Rule.

b. Compressor Stations

As discussed above, the 2016 NSPS OOOOa required quarterly monitoring of compressor stations for both VOC and methane emissions, and it also permitted waiver from one quarterly monitoring event when the average temperature is below 0 °F for two consecutive months because it is technically infeasible for the OGI camera (and EPA Method 21 instruments) to operate below this temperature. After the 2020 Policy Rule rescinded the methane standards, the 2020 Technical Rule reduced the monitoring requirements for the VOC standards to require only semiannual monitoring and, in doing so, removed the waiver. Upon enactment of the CRA resolution, compressor stations again became subject to quarterly monitoring pursuant to the reinstated 2016 NSPS OOOOa methane standards, and the waiver as it applied to the methane standards was also reinstated. Consistent with our proposal to align the monitoring requirements for VOCs with the monitoring requirements for methane, the EPA is also proposing to reinstate the waiver for the VOC standards as specified in the 2016 NSPS OOOOa.

c. Well Sites and Compressor Stations on the Alaska North Slope

The EPA is proposing to amend the 2016 NSPS OOOOa to require that new, reconstructed, and modified compressor stations located on the Alaska North Slope that startup (initially, or after reconstruction or modification) between September and March to conduct initial monitoring of methane emissions within 6 months of startup, or by June 30, whichever is later. The EPA made a similar amendment to the initial monitoring of methane and VOC emissions at well sites located on the Alaska North Slope in the March 12, 2018 amendments to the 2016 NSPS OOOOa (''2018 NSPS OOOOa Rule'').[183] As explained in that action, such separate requirements were warranted due to the area's extreme cold temperatures, which for approximately half of the year are below the temperatures at which the monitoring instruments are designed to operate. The 2020 Technical Rule made this amendment for VOC emissions from gathering and boosting compressor stations located in the Alaska North Slope for this same reason.

The EPA is also proposing to amend the 2016 NSPS OOOOa to require annual monitoring of methane and VOC emissions at all compressor stations located on the Alaska North Slope, with subsequent annual monitoring at least 9 months apart but no more than 13 months apart. In the 2018 NSPS OOOOa Rule, the EPA similarly amended the monitoring frequency for well sites located on the Alaska North Slope to annual monitoring to accommodate the extreme cold temperature. 83 FR 10628 (March 12, 2018). For the same reason, in the 2020 Technical Rule, the EPA amended the 2016 NSPS OOOOa to require annual VOC monitoring at gathering and boosting compressor stations located on the Alaska North Slope because extreme cold temperatures make it technically infeasible to conduct OGI monitoring for over half of a year.[184] Because the same difficulties would arise with respect to monitoring for fugitive methane emissions from gathering and boosting compressor stations or to monitoring of methane and VOC emissions from compressor stations in the transmission and storage segment, the EPA is proposing to amend the 2016 NSPS OOOOa to require that all compressor stations located on the Alaska North Slope conduct annual monitoring of both methane and VOC emissions.

Further, the EPA is proposing to extend the deadline for conducting initial monitoring of both VOC and methane emissions from 60 days to 90 days for all well sites and compressor stations located on the Alaska North Slope that startup or are modified between April and August. In the 2020 Technical Rule, the EPA made this amendment for initial VOC monitoring to allow the well site or gathering and boosting compressor station to reach normal operating conditions. 85 FR 57406. For the same reason, we are proposing to further amend the 2016 NSPS OOOOa to apply this same 90-day initial monitoring requirement to initial monitoring of fugitive methane and VOC emissions from all well sites and compressor stations located on the Alaska North Slope that startup or are modified between April and August.

d. Modification

The 2016 NSPS OOOOa, as originally promulgated, provided that ''[f]or purposes of the fugitive emissions standards at 40 CFR 60.5397a, [a] well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (*e.g.,* centralized tank batteries).'' 40 CFR 60.5430a. However, the original 2016 NSPS OOOOa defined ''modification'' only with respect to a well site and was silent on what constitutes modification to a well site that is a separate tank battery surface site. Specifically, 40 CFR 60.5365a(i), as promulgated in 2016, specified that, for the purposes of fugitive emissions components at a well site, a modification occurs when (1) a new well is drilled at an existing well site, (2) a well is hydraulically fractured at an existing well site, or (3) a well is hydraulically refractured at an existing well site. See 40 CFR 60.5365a(i).

Because this provision was silent on when modification occurs at a well site that is a separate tank battery surface site, the 2020 Technical Rule added language to clarify that a modification of a well site that is a separate tank battery surface site occurs when (1) any of the actions listed above for well sites occurs

[182] See *https://pubs.acs.org/doi/10.1021/acs.est.0c02927, https://data.permianmap.org/pages/flaring,* and *https://www.edf.org/sites/default/files/documents/PermianMapMethodology_1.pdf.*

[183] 83 FR 10628 (March 12, 2018).

[184] See Docket ID Nos. EPA–HQ–OAR–2010–0505–7682 and EPA–HQ–OAR–2010–0505–12434. See also FLIR Systems, Inc. product specifications for GF300/320 model OGI cameras at *http://www.flir.com/ogi/display/?id=55671* and Thermo Fisher Scientific product specification for TVA–2020 at *https://assets.thermofisher.com/TFS-Assets/LSG/Specification-Sheets/EPM-TVA2020.pdf.*

at an existing separate tank battery surface site, (2) a well modified as described above sends production to an existing separate tank battery surface site, or (3) a well site subject to the fugitive emissions requirements removes all major production and processing equipment such that it becomes a wellhead-only well site and sends production to an existing separate tank battery surface site. Because the 2020 Technical Rule amended only the VOC standards in the 2016 NSPS OOOOa, and since this definition of modification equally applies to fugitive methane emissions from a separate tank battery surface site, the EPA is proposing to apply this definition of modification for purposes of determining when modification occurs at a separate tank battery surface site triggering the methane standards for fugitive emissions at well sites.

e. Initial Monitoring for Well Sites and Compressor Stations

The 2016 NSPS OOOOa, as originally promulgated, had required monitoring of methane and VOC fugitive emissions at well sites and compressor stations to begin within 60 days of startup (of production in the case of well sites) or modification. The 2020 Technical Rule extended this time frame to 90 days for well sites and gathering and boosting compressor stations in response to comments stating that well sites and compressor stations do not achieve normal operating conditions within the first 60 days of startup and suggesting that the EPA allow 90 days to 180 days. The EPA agreed that additional time to allow the well site or compressor station to reach normal operating conditions is warranted, considering the purpose of the initial monitoring is to identify any issues associated with installation and startup of the well site or compressor station. By providing sufficient time to allow owners and operators to conduct the initial monitoring survey during normal operating conditions, the EPA expects that there will be more opportunity to identify and repair sources of fugitive emissions, whereas a partially operating site may result in missed emissions that remain unrepaired for a longer period of time. 85 FR 57406. These same reasons apply regardless of pollutant or the location of the compressor station; therefore, the EPA is proposing to further amend the 2016 NSPS OOOOa to extend the deadline for conducting initial monitoring from 60 to 90 days for monitoring both VOC and methane fugitive emissions at all well sites and compressor stations (except those on the Alaska North Slope which are separately regulated as discussed in section X.B.4.c).

f. Repair Requirements

The 2020 Technical Rule made certain amendments to the 2016 NSPS OOOOa repair requirements associated with monitoring of fugitive VOC emissions at well sites and gathering and boosting compressor stations. For the same reasons provided in the 2020 Technical Rule and reiterated below, the EPA is proposing to similarly amend the 2016 NSPS OOOOa repair requirements associated with monitoring of methane emissions at well sites and gathering and boosting compressor stations and monitoring of VOC and methane fugitive emissions at compressor stations in the transmission and storage segment.

Specifically, the EPA is proposing to require a first attempt at repair within 30 days of identifying fugitive emissions and final repair, including the resurvey to verify repair, within 30 days of the first attempt at repair. The 2016 NSPS OOOOa, as originally promulgated, required repair within 30 days of identifying fugitive emissions and a resurvey to verify that the repair was successful within 30 days of the repair. Stakeholders raised questions regarding whether emissions identified during the resurvey would result in noncompliance with the repair requirement. In the 2020 Technical Rule, the EPA clarified that repairs should be verified as successful prior to the repair deadline and added definitions for the terms ‘‘first attempt at repair’’ and ‘‘repaired.’’ Specifically, the definition of ‘‘repaired’’ includes the verification of successful repair through a resurvey of the fugitive emissions component. The EPA is similarly proposing to apply these amendments to the repair requirements made in the 2020 Technical Rule to the repair requirements associated with monitoring of methane emissions at well sites and gathering and boosting compressor stations as well as monitoring of VOC and methane fugitive emissions at compressor stations in the transmission and storage segment and monitoring.

In addition, the EPA is proposing that delayed repairs be completed during the ‘‘next scheduled compressor station shutdown for maintenance, scheduled well shutdown, scheduled well shut-in, after a scheduled vent blowdown, or within 2 years, whichever is earliest.’’ The proposed amendment would clarify that completion of delayed repairs is required during scheduled shutdown for maintenance, and not just any shutdown.

In 2018 NSPS OOOOa Rule the EPA amended the 2016 NSPS OOOOa to specify that, where the repair of a fugitive emissions component is ‘‘technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown, well shutdown, well shut-in, after a planned vent blowdown, or within 2 years, whichever is earlier.’’ [185] During the rulemaking for the 2020 Technical Rule, the EPA received comments expressing concerns with requiring repairs during the next scheduled compressor station shutdown, without regard to whether the shutdown is for maintenance purposes. The commenters stated that repairs must be scheduled and that where a planned shutdown is for reasons other than scheduled maintenance, completion of the repairs during that shutdown may be difficult and disrupt gas transmission. The EPA agrees that requiring the completion of delayed repairs only during those scheduled compressor station shutdowns where maintenance activities are scheduled is reasonable and anticipates that these maintenance shutdowns occur on a regular schedule. Accordingly, in the 2020 Technical Rule the EPA further amended this provision by adding the term ‘‘for maintenance’’ to clarify that repair must be completed during the ‘‘next scheduled compressor station shutdown for maintenance’’ or other specified scheduled events, or within 2 years, whichever is the earliest. For the same reason, the EPA is proposing the same clarifying amendment to the delay of repair requirements for fugitive methane emissions at well sites and gathering and boosting compressor stations and fugitive VOC and methane fugitive emissions at compressor stations in the transmission and storage segment.

g. Definitions Related to Fugitive Emissions at Well Sites and Compressor Stations

The 2020 Technical Rule made certain amendments to the definition of a well site and the definition for startup of production as they relate to fugitive VOC emissions requirements at well sites. For the same reasons provided in the 2020 Technical Rule and reiterated below, the EPA is proposing to similarly amend these definitions as they relate to the fugitive methane emissions requirements at well sites.

[185] 83 FR 10638, 40 CFR 60.5397a(h)(2).

The 2020 Technical Rule amended the definition of well site, for purposes of VOC fugitive emissions monitoring, to exclude equipment owned by third parties and oilfield solid waste and wastewater disposal wells. The amended definition for ''well site'' excludes third party equipment from the fugitive emissions requirements by excluding ''the flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components located downstream of this flange.'' To clarify this exclusion, the 2020 Technical Rule defines ''custody meter'' as ''the meter where natural gas or hydrocarbon liquids are measured for sales, transfers, and/or royalty determination,'' and the ''custody meter assembly'' as ''an assembly of fugitive emissions components, including the custody meter, valves, flanges, and connectors necessary for the proper operation of the custody meter.'' This exclusion was added for several reasons, including consideration that owners and operators may not have access or authority to repair this third-party equipment and because the custody meter ''is used effectively as the cash register for the well site and provides a clear separation for the equipment associated with production of the well site, and the equipment associated with putting the gas into the gas gathering system.'' 83 FR 52077 (October 15, 2018).

The definition of a well site was also amended in the 2020 Technical Rule to exclude Underground Injection Control (UIC) Class I oilfield disposal wells and UIC Class II oilfield wastewater disposal wells. The EPA had proposed to exclude UIC Class II oilfield wastewater disposal wells because of our understanding that they have negligible fugitive VOC and methane emissions. 83 FR 52077. Comments received on the 2020 Technical rulemaking effort further suggested, and the EPA agreed, that we also should exclude UIC Class I oilfield disposal wells because of their low VOC and methane emissions. Both types of disposal wells are permitted through UIC programs under the Safe Drinking Water Act for protection of underground sources of drinking water. For consistency, the 2020 Technical Rule adopted the definitions for UIC Class I oil field disposal wells and UIC Class II oilfield wastewater disposal wells under the Safe Drinking Water Act definitions in excluding them from the definition of a well site in the 2016 NSPS OOOOa. Specifically, the 2020 Technical Rule defined a UIC Class I oilfield disposal well as ''a well with a UIC Class I permit that meets the definition in 40 CFR 144.6(a)(2) and receives eligible fluids from oil and natural gas exploration and production operations.'' Additionally, the 2020 Technical Rule defines a UIC Class II oilfield wastewater disposal well as ''a well with a UIC Class II permit where wastewater resulting from oil and natural gas production operations is injected into underground porous rock formations not productive of oil or gas, and sealed above and below by unbroken, impermeable strata.'' As amended, UIC Class I and UIC Class II disposal wells are not considered well sites for the purposes of VOC fugitive emissions requirements. Because the 2020 Technical Rule, as finalized, addressed only VOC emissions in the production and processing segment, the EPA is proposing the same exclusion and definition of ''well site'' for the purposes of fugitive emissions monitoring of methane emissions at well sites.

The EPA is also proposing to apply the definition for ''startup of production'' for purposes of well site fugitive emissions requirements for VOC to these requirements as they relate to methane. The 2016 NSPS OOOOa initially contained a definition for ''startup of production'' as it relates to the well completion standards that reduce emissions from hydraulically fractured wells. For that purpose, the term was defined as ''the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.'' 81 FR 25936 (June 3, 2016). The 2020 Technical Rule amended the definition of ''startup of production'' to separately define the term as it relates to fugitive VOC emissions requirements at well sites. Specifically, ''. . .[f]or the purposes of the fugitive monitoring requirements of 40 CFR 60.5397a, *startup of production* means the beginning of the continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water'' 85 FR 57459 (September 15, 2020). This separate definition clarifies that fugitive emissions monitoring applies to both conventional and unconventional (hydraulically fractured) wells. For this same reason, the EPA is proposing to apply this same definition of ''startup of production'' to fugitive emissions monitoring of methane emissions at well sites.

h. Monitoring Plan

The 2016 NSPS OOOOa, as originally promulgated, required that each fugitive emissions monitoring plan include a site map and a defined observation path to ensure that the OGI operator visualizes all of the components that must be monitored during each survey. The 2020 Technical Rule amended this requirement to allow the company to specify procedures that would meet this same goal of ensuring every component is monitored during each survey. While the site map and observation path are one way to achieve this, other options can also ensure monitoring, such as an inventory or narrative of the location of each fugitive emissions component. The EPA stated in the 2020 Technical Rule that ''these company-defined procedures are consistent with other requirements for procedures in the monitoring plan, such as the requirement for procedures for determining the maximum viewing distance and maintaining this viewing distance during a survey.'' 85 FR 57416 (September 15, 2020). Because the same monitoring device is used to monitor both methane and VOC emissions, the same company-defined procedures for ensuring each component is monitored are appropriate. Therefore, the EPA is proposing to similarly amend the monitoring plan requirements for methane and for compressor stations to allow company procedures in lieu of a sitemap and an observation path.

i. Recordkeeping and Reporting

The 2020 Technical Rule amended the 2016 NSPS OOOOa to streamline the recordkeeping and reporting requirements for the VOC fugitive emissions standards. The amendments removed the requirement to report or keep certain records that the EPA determined were redundant or unnecessary; in some instances, the rule replaced those requirements or added new requirements that could better demonstrate and ensure compliance, in particular where the underlying requirement was also amended (*e.g.,* repair requirements). These amendments reflect consideration of the public comments received on the proposal for that rulemaking. The purpose and function of the recordkeeping and reporting requirements are equally applicable to methane and VOCs, and therefore, are not pollutant specific. For the same reasons the EPA streamlined these requirements in the 2020 Technical Rule,[186] the EPA is proposing to apply these streamlined recordkeeping and reporting requirements for methane

[186] See 85 FR 57415 (September 15, 2020).

emissions from sources subject to NSPS OOOOa.

For each collection of fugitive emissions components located at a well site or compressor station, the following amendments were made to the recordkeeping and reporting requirements in the 2020 Technical Rule:

- Revised the requirements in 40 CFR 60.5397a(d)(1) to require inclusion of procedures that ensure all fugitive emissions components are monitored during each survey within the monitoring plan.
- Removed the requirement to maintain records of a digital photo of each monitoring survey performed, captured from the OGI instrument used for monitoring when leaks are identified during the survey because the records of the leaks provide proof of the survey taking place.
- Removed the requirement to maintain records of the number and type of fugitive emissions components or digital photo of fugitive emissions components that are not repaired during the monitoring survey once repair is completed and verified with a resurvey.
- Required records of the date of first attempt at repair and date of successful repair.
- Revised reporting to specify the type of site (*i.e.,* well site or compressor station) and when the well site changes status to a wellhead-only well site.
- Removed requirement to report the name or ID of operator performing the monitoring survey.
- Removed requirement to report the number and type of difficult-to-monitor and unsafe-to-monitor components that are monitored during each monitoring survey.
- Removed requirement to report the ambient temperature, sky conditions, and maximum wind speed.
- Removed requirement to report the date of successful repair.
- Removed requirement to report the type of instrument used for resurvey.

5. AMEL

The 2020 Technical Rule made the following amendments to the provisions associated with applications for use of an AMEL for VOC work practice standards for well completions, reciprocating compressors, and the collection of fugitive emissions components located at well sites and gathering and boosting compressor stations. For the same reasons provided in the 2020 Technical Rule and reiterated below, the EPA is proposing to similarly amend the 2016 NSPS OOOOa provisions associated with applications for use of an AMEL for methane work practice standards at well sites and gathering and boosting compressor stations and VOC and methane work practice standards at compressor stations in the transmission and storage segment.

The 2020 Technical Rule amended the AMEL application requirements to help streamline the process for evaluation and possible approval of advanced measurement technologies. The amendments included allowing submission of applications by, among others, owners and operators of affected facilities, manufacturers or vendors of leak detection technologies, or trade associations. The 2020 Technical Rule ''allows any person to submit an application for an AMEL under this provision.'' 85 FR 57422 (September 15, 2020). However, the 2020 Technical Rule, like the 2016 NSPS OOOOa still requires that the application include sufficient information to demonstrate that the AMEL achieves emission reductions at least equivalent to the work practice standards in the rule. To that end, the 2020 Technical Rule ''requires applications for these AMEL to include site-specific information to demonstrate equivalent emissions reductions, as well as site-specific procedures for ensuring continuous compliance.'' *Id.* At a minimum, the application should include field data that encompass seasonal variations, which may be supplemented with modeling analyses, test data, and/or other documentation. The specific work practice(s), including performance methods, quality assurance, the threshold that triggers action, and the mitigation thresholds are also required as part of the AMEL application. For example, for a technology designed to detect fugitive emissions, information such as the detection criteria that indicate fugitive emissions requiring repair, the time to complete repairs, and any methods used to verify successful repair would be required.

Since the 2020 Technical Rule changes to the AMEL provisions in the 2016 NSPS OOOOa are procedural in the sense that they mostly speak to the ''minimum information that must be included in each application in order for the EPA to make a determination of equivalency and, thus, be able to approve an alternative'' the EPA believes that it is appropriate to retain those amendments. 85 FR 57422 (September 15, 2020). If finalized, the application must demonstrate equivalence as explained above for both the reduction of methane and VOC emissions. Because the 2020 Technical Rule amended only the VOC standards in the 2016 NSPS OOOOa, and since EPA believes that basis for promulgation of this provision for AMEL applications equally applies to work practices standards for methane emissions at facilities in the production and processing segments and VOC and methane emissions at facilities in the transmission and storage segment, the EPA is proposing to apply these application requirements for all applicants seeking an AMEL for the methane and VOC work practice standards in NSPS OOOOa.

6. Alternative Fugitive Emissions Standards Based on Equivalent State Programs

The 2020 Technical Rule added a new section (at 40 CFR 60.5399a) which served two purposes. First, the new section outlined procedures for State, local, and Tribal authorities to seek the EPA's approval of their VOC fugitive emissions standards at well sites and gathering and boosting compressor stations as an alternative to the Federal standards. Second, the new section approved specific voluntary alternative standards for six States. For the same reasons provided in the 2020 Technical Rule and reiterated below, the EPA is proposing to similarly allow this new section to apply to fugitive emissions standards for methane fugitive emissions at well sites and gathering and boosting compressor stations, and VOC and methane fugitive emissions at compressor stations in the transmission and storage segment.

The 2020 Technical Rule added this new section in part to allow the use of specific alternative fugitive emissions standards for VOC emissions for six State fugitive emissions programs that the EPA had concluded were at least equivalent to the fugitive emissions monitoring and repair requirements at 40 CFR 60.5397a(e), (f), (g), and (h) as amended in that rule.[187] These approved alternative fugitive emissions standards may be used for certain individual well sites or gathering and boosting compressor stations that are subject to VOC fugitive emissions monitoring and repair so long as the source complies with specified Federal requirements applicable to each approved alternative State program and included in 40 CFR 60.5399a(f) through (n). For example, a well site that is subject to the requirements of Pennsylvania General Permit 5A, section G, effective August 8, 2018, could choose to comply with those

[187] See memorandum, ''Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Final Standards at 40 CFR part 60, subpart OOOOa,'' located at Docket ID No. EPA–HQ–OAR–2017–0483. January 17, 2020.

standards in lieu of the monitoring, repair, recordkeeping, and reporting requirements in the NSPS for fugitive emissions at well sites. However, in that example, the owner or operator must develop and maintain a fugitive emissions monitoring plan, as required in 40 CFR 60.5397a(c) and (d), and must monitor all of the fugitive emissions components, as defined in 40 CFR 60.5430a, regardless of the components that must be monitored under the alternative standard (*i.e.,* under Pennsylvania General Permit 5A, Section G in the example). Additionally, the facility choosing to use the EPA-approved alternative standard must submit, as an attachment to its annual report for NSPS OOOOa, the report that is submitted to its State in the format submitted to the State, or the information required in the report for NSPS OOOOa if the State report does not include site-level monitoring and repair information. If a well site is located in the State but is not subject to the State requirements for monitoring and repair (*i.e.,* not obligated to monitor or repair fugitive emissions), then the well site must continue to comply with the Federal requirements of the NSPS at 40 CFR 60.5397a in its entirety.

In addition to providing the EPA-approved voluntary alternative fugitive emissions standards for well sites and gathering and boosting compressor stations located in California, Colorado, Ohio, Pennsylvania, and Texas, and well sites in Utah, the amendments in the 2020 Technical Rule provide application requirements to request the EPA approval of an alternative fugitive emissions standards as State, local, and Tribal programs continue to develop. Applications for the EPA approval of alternative fugitive emissions standards based on State, local, or Tribal programs may be submitted by any interested person, including individuals, corporations, partnerships, associations, States, or municipalities. Similar to the application process for AMEL for advanced measurement technologies, the application must include sufficient information to demonstrate that the alternative fugitive emissions standards achieve emissions reductions at least equivalent to the fugitive emissions monitoring and repair requirements in the Federal NSPS. At a minimum, the application must include the monitoring instrument, monitoring procedures, monitoring frequency, definition of fugitive emissions requiring repair, repair requirements, recordkeeping, and reporting requirements. If any of the sections of the State regulations or permits approved as alternative fugitive emissions standards are changed at a later date, the State must follow the procedures outlined in 40 CFR 60.5399a to apply for a new evaluation of equivalency.

As part of the 2018 proposed rule (83 FR 52056, October 15, 2018) that resulted in the 2020 Technical Rule, the EPA evaluated the specific State programs for both methane and VOC emissions at well sites, gathering and boosting compressor stations, and compressor stations in the transmission and storage segment as discussed in detail in a memorandum to that docket evaluating the equivalency of State fugitive emissions programs.[188] The EPA is now proposing that all well sites and compressor stations located in and subject to the specified State regulations in 40 CFR 60.5399a may utilize these alternative fugitive emissions standards for both methane and VOC fugitive emissions. In the 2020 Technical Rule the EPA concluded that these monitoring, repair, recordkeeping, and reporting requirements were equivalent to the same types of requirements in the 2016 NSPS OOOOa for VOC at well sites and gathering and boosting compressor stations. See 85 FR 57424. The monitoring instrument (*i.e.,* OGI or EPA Method 21) will detect, at the same time, both methane and VOC emissions without speciating these emissions. Therefore, detection of one of these pollutants is also detection of the other pollutant. For the same reasons provided in the 2020 Technical Rule, and explained in the associated State equivalency memos, the EPA proposes to find these same State fugitive emissions standards (as specified in 40 CFR 60.5399a(f) through (n)) equivalent to the specified Federal methane fugitive emissions standards for well sites and gathering and boosting stations, and the methane and VOC fugitive emissions standards for compressor stations in the transmission and storage segment. The EPA is also proposing to allow State, local, and Tribal agencies to apply for the EPA approval of their fugitives monitoring program as an alternative to the Federal NSPS for methane. Put another way, the EPA is proposing to include methane throughout 40 CFR 60.5399a.

The EPA recognizes that the determinations of equivalence included in the 2020 Technical Rule were based on the fugitive emissions monitoring requirements that existed at that time for the 2016 NSPS OOOOa which, based on other changes in the 2020 Technical Rule, included an exemption from monitoring for low production well sites and required semiannual monitoring at gathering and boosting compressor stations. As explained above, the EPA is proposing to repeal both of those changes, and require semiannual monitoring at all well sites, including those with low production, and quarterly monitoring at gathering and boosting compressor stations. These proposed changes to the 2016 NSPS OOOOa fugitive emissions requirements do not impact the EPA's conclusion that the six previously approved alternative State programs are equivalent to the Federal standards. Even so, the EPA is proposing regulatory changes within the alternative State program provisions in 2016 NSPS OOOOa to account for these proposed changes to the Federal standards. See the redline version of regulatory text in the docket at Docket ID No. EPA–HQ–OAR–2021–0317. These changes are intended to ensure that the previously approved alternative State programs continue to maintain equivalency with the Federal standards if NSPS OOOOa is revised as proposed here. With these changes, the EPA continues to find that the alternative State programs that were previously approved are still equivalent with, if not better than, the Federal requirements.

7. Onshore Natural Gas Processing Plants

a. Capital Expenditure

The 2020 Technical Rule made certain amendments to the 2016 NSPS OOOOa definition of capital expenditure as it relates to modifications for VOC LDAR requirements at onshore natural gas processing plants. For the same reasons provided in the 2020 Technical Rule and reiterated below, the EPA is proposing to similarly amend this definition as it relates to the methane LDAR requirements at onshore natural gas processing plants.

The 2020 Technical Rule amended the definition of ''capital expenditure'' at 40 CFR 50.5430a by replacing the equation used to determine the percent of replacement cost, ''Y.'' This amendment was necessary because, as originally promulgated, the equation for determining ''Y'' would result in an error, thus, making it difficult to determine whether a capital expenditure had occurred using the NSPS OOOOa equation. The 2020 Technical Rule replaced the equation with an equation that utilizes the consumer price indices, ''CPI'' because it more appropriately reflects inflation than the original equation. Specifically, the equation for ''Y'' as amended in the

[188] See Docket ID Nos. EPA–HQ–OAR–2017–0483–0041 and EPA–HQ–OAR–2017–0483–2277.

2020 Technical Rule, is based on the CPI, where ''Y'' equals the CPI of the date of construction divided by the most recently available CPI of the date of the project, or ''CPI_N/CPI_{PD}.'' Further, the 2020 Technical Rule specifies that the ''annual average of the CPI for all urban consumers (CPI–U), U.S. city average, all items'' must be used for determining the CPI of the year of construction, and the ''CPI–U, U.S. city average, all items'' must be used for determining the CPI of the date of the project. This amendment clarified that the comparison of costs is between the original date of construction of the process unit (the affected facility) and the date of the project which adds equipment to the process unit. For these same reasons, the EPA is proposing that the definition of ''capital expenditure,'' as amended by the 2020 Technical Rule, also be used to determine whether modification had occurred and thus triggers the applicability of the methane LDAR requirements at onshore natural gas processing plants in the 2016 NSPS OOOOa.

b. Initial Compliance Period

The 2020 Technical Rule amended the VOC standards for onshore natural gas processing plants to specify that the initial compliance deadline for the equipment leak standards is 180 days. The EPA is proposing to apply this clarification to the initial compliance deadline with the methane standards for equipment leaks at onshore natural gas processing plants.

As explained in the 2020 Technical Rule, the EPA added a provision requiring compliance ''as soon as practicable, but no later than 180 days after initial startup'' because that provision was in the NSPS for equipment leaks of VOC at onshore natural gas processing plants when it was first promulgated, specifically at 40 CFR 60.632(a) of part 60, subpart KKK (NSPS KKK). 85 FR 57408. This provision at 40 CFR 60.632(a) provides up to 180 days to come into compliance with NSPS KKK. In 2012, the EPA revised the standards in NSPS KKK with the promulgation of NSPS OOOO [189] by lowering the leak definition for valves from 10,000 ppm to 500 ppm and requiring the monitoring of connectors. 77 FR 49490, 49498. While the EPA did not mention that it was also amending the 180-day compliance deadline in NSPS OOOO, this provision at 40 CFR 60.632(a) was not included in NSPS OOOO and, in turn, was not included in NSPS OOOOa. During the rulemaking for NSPS OOOOa, the EPA declined a request to include this provision at 40 CFR 60.632(a) in NSPS OOOOa, explaining that such inclusion was not necessary because NSPS OOOOa already includes by reference a similar provision (*i.e.,* 40 CFR 60.482–1a(a)) which requires each owner or operator to ''demonstrate compliance . . . within 180 days of initial startup,'' 80 FR 56593, 56647–8. However, in reassessing the issue during the rulemaking for the 2020 Technical Rule, the EPA noted that NSPS KKK includes both the provision in 40 CFR 60.632(a) and 40 CFR 60.482–1(a), which contains a provision that is the same as the one described above at 40 CFR 60.482–1a(a), thus suggesting that 40 CFR 60.632(a) is not redundant or unnecessary. In fact, the absence of this provision in NSPS OOOO/OOOOa raised a question as to whether compliance is required within 30 days for equipment that is required to be monitored monthly. To clarify this confusion and remain consistent with NSPS KKK, the 2020 Technical Rule amended NSPS OOOOa to reinstate this provision at 40 CFR 60.632(a). For the same reasons explained above, the EPA is proposing to similarly apply this provision to compliance with methane standards for the equipment leaks at onshore natural gas processing plants.

This provision clarifies that monitoring must begin as soon as practicable, but no later than 180 days after the initial startup of a new, modified, or reconstructed process unit at an onshore natural gas processing plant. Once started, monitoring must continue with the required schedule. For example, if pumps are monitored by month 3 of the initial startup period, then monthly monitoring is required from that point forward. This initial compliance period is different than the compliance requirements for newly added pumps and valves within a process unit that is already subject to a LDAR program. Initial monitoring for those newly added pumps and valves is required within 30 days of the startup of the pump or valve (*i.e.,* when the equipment is first in VOC service).

8. Technical Corrections and Clarifications

The 2020 Technical Rule also revised the 2016 NSPS OOOOa for VOC emissions to include certain additional technical corrections and clarifications. In this action, the EPA is proposing to apply these same technical corrections and clarifications to the methane standards for production and processing segments and/or the methane and VOC standards for the transmission and storage segment in the 2016 NSPS OOOOa, as appropriate. Specifically, the EPA is proposing to:

- Revise 40 CFR 60.5385a(a)(1), 60.5410a(c)(1), 60.5415a(c)(1), and 60.5420a(b)(4)(i) and (c)(3)(i) to clarify that hours or months of operation at reciprocating compressor facilities must be measured beginning with the date of initial startup, the effective date of the requirement (August 2, 2016), or the last rod packing replacement, whichever is latest.
- Revise 40 CFR 60.5393a(b)(3)(ii) to correctly cross-reference paragraph (b)(3)(i) of that section.
- Revise 40 CFR 60.5397a(c)(8) to clarify the calibration requirements when Method 21 of appendix A–7 to part 60 is used for fugitive emissions monitoring.
- Revise 40 CFR 60.5397a(d)(3) to correctly cross-reference paragraphs (g)(3) and (4) of that section.
- Revise 40 CFR 60.5401a(e) to remove the word ''routine'' to clarify that pumps in light liquid service, valves in gas/vapor service and light liquid service, and pressure relief devices (PRDs) in gas/vapor service within a process unit at an onshore natural gas processing plant located on the Alaska North Slope are not subject to any monitoring requirements, whether the monitoring is routine or nonroutine.
- Revise 40 CFR 60.5410a(e) to correctly reference pneumatic pump affected facilities located at a well site as opposed to pneumatic pump affected facilities not located at a natural gas processing plant (which would include those not at a well site). This correction reflects that the 2016 NSPS OOOOa do not contain standards for pneumatic pumps at gathering and boosting compressor stations. 81 FR 35850.
- Revise 40 CFR 60.5411a(a)(1) to remove the reference to paragraphs (a) and (c) of 40 CFR 60.5412a for reciprocating compressor affected facilities.
- Revise 40 CFR 60.5411a(d)(1) to remove the reference to storage vessels, as this paragraph applies to all the sources listed in 40 CFR 60.5411a(d), not only storage vessels.
- Revise 40 CFR 60.5412a(a)(1) and (d)(1)(iv) to clarify that all boilers and process heaters used as control devices on centrifugal compressors and storage vessels must introduce the vent stream into the flame zone. Additionally, revise 40 CFR 60.5412a(a)(1)(iv) and (d)(1)(iv)(D) to clarify that the vent stream must be introduced with the primary fuel or as the primary fuel to

[189] ''Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for Which Construction, Modification or Reconstruction Commenced After August 23, 2011, and on or before September 18, 2015.''

meet the performance requirement option. This is consistent with the performance testing exemption in 40 CFR 60.5413a and continuous monitoring exemption in 40 CFR 60.5417a for boilers and process heaters that introduce the vent stream with the primary fuel or as the primary fuel.

• Revise 40 CFR 60.5412a(c) to correctly reference both paragraphs (c)(1) and (2) of that section, for managing carbon in a carbon adsorption system.

• Revise 40 CFR 60.5413a(d)(5)(i) to reference fused silica-coated stainless steel evacuated canisters instead of a specific name brand product.

• Revise 40 CFR 60.5413a(d)(9)(iii) to clarify the basis for the total hydrocarbon span for the alternative range is propane, just as the basis for the recommended total hydrocarbon span is propane.

• Revise 40 CFR 60.5413a(d)(12) to clarify that all data elements must be submitted for each test run.

• Revise 40 CFR 60.5415a(b)(3) to reference all applicable reporting and recordkeeping requirements.

• Revise 40 CFR 60.5416a(a)(4) to correctly cross-reference 40 CFR 60.5411a(a)(3)(ii).

• Revise 40 CFR 60.5417a(a) to clarify requirements for controls not specifically listed in paragraph (d) of that section.

• Revise 40 CFR 60.5422a(b) to correctly cross-reference 40 CFR 60.487a(b)(1) through (3) and (b)(5).

• Revise 40 CFR 60.5422a(c) to correctly cross-reference 40 CFR 60.487a(c)(2)(i) through (iv) and (c)(2)(vii) through (viii).

• Revise 40 CFR 60.5423a(b) to simplify the reporting language and clarify what data are required in the report of excess emissions for sweetening unit affected facilities.

• Revise 40 CFR 60.5430a to remove the phrase ''including but not limited to'' from the ''fugitive emissions component'' definition. During the 2016 NSPS OOOOa rulemaking, the EPA stated in a response to comment that this phrase is being removed,[190] but did not do so in that rulemaking.

• Revise 40 CFR 60.5430a to remove the phrase ''at the sales meter'' from the ''low pressure well'' definition to clarify that when determining the low-pressure status of a well, pressure is measured within the flow line, rather than at the sales meter.

• Revise Table 3 of 40 CFR part 60, subpart OOOOa, to correctly indicate that the performance tests in 40 CFR 60.8 do not apply to pneumatic pump affected facilities.

• Revise Table 3 of 40 CFR part 60, subpart OOOOa, to include the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station in the list of exclusions for notification of reconstruction.

• Revise 40 CFR 60.5393a(f), 60.5410a(e)(8), 60.5411a(e), 60.5415a(b) introductory text and (b)(4), 60.5416a(d), and 60.5420a(b) introductory text and (b)(13), and introductory text in 40 CFR 60.5411a and 60.5416a, to remove language associated with the administrative stay we issued under section 307(d)(7)(B) of the CAA in ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Grant of Reconsideration and Partial Stay'' (82 FR 25730, June 5, 2017). The administrative stay was vacated by the D.C. Circuit on July 3, 2017.

XI. Summary of Proposed NSPS OOOOb and EG OOOOc

This section presents a summary of the specific NSPS standards and EG presumptive standards the EPA is proposing for various types of equipment and emission points. More details of the rationale for these standards and requirements, including alternative compliance options and exemptions to the standards, are provided in section XII of this preamble and the TSD for this action in the public docket. As stated in section I, the EPA intends to provide draft regulatory text for the proposed NSPS OOOOb and EG OOOOc in a supplemental proposal.

A. Fugitive Emissions From Well Sites and Compressor Stations

Fugitive emissions are unintended emissions that can occur from a range of equipment at any time. The magnitude of these emissions can also vary widely. The EPA has historically targeted fugitive emissions from the Crude Oil and Natural Gas source category through ground-based component level monitoring using OGI, or alternatively, EPA Method 21.

The EPA is proposing the following monitoring requirements and presumptive standards for the collection of fugitive emissions components located at well sites and compressor stations. Additional details for the proposed standards and proposed presumptive standards are included in the following subsections. Information received through the various solicitations in this section may be used to evaluate if a change in the BSER is appropriate from the proposed requirements below, specifically consideration of alternative measurement technologies as the BSER. Any potential changes would be addressed through a supplemental proposal.

• Well sites with total site-level baseline methane emissions less than 3 tpy: Demonstration, based on a site-specific survey, that actual emissions are reflected in the baseline methane emissions calculation,

• Well sites with total site-level baseline methane emissions of 3 tpy or greater: Quarterly OGI or EPA Method 21 monitoring,

• (Co-proposal) 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,

• (Co-proposal) Well sites with total site-level baseline methane emissions of 8 tpy or greater: Quarterly OGI or EPA Method 21 monitoring,

• Compressor stations: Quarterly OGI or EPA Method 21 monitoring,

• Well sites and compressor stations located on the Alaska North Slope: Annual monitoring, with separate initial monitoring requirements, and

• Alternative screening approach for all well sites and compressor stations: Bimonthly screening surveys using advanced measurement technology and annual OGI or EPA Method 21 monitoring at each individual well site or compressor station.

1. Definition of Fugitive Emissions Component

A key factor in evaluating how to target fugitive emissions is clearly identifying the emissions of concern and the sources of those emissions. In the 2016 NSPS OOOOa, the EPA defined ''fugitive emissions component'' as ''any component with the potential to emit methane and VOCs'' and included several specific component types, ranging from valves and connectors, to openings on controlled storage vessels that were not regulated under NSPS OOOOa.

However, data shows that the universe of components with potential for fugitive emissions is broader than the illustrative list included in the 2016 NSPS OOOOa, and that the majority of the largest emissions events occur from a subset of components that may not have been clearly included in the definition. Therefore, the EPA is proposing a new definition for ''fugitive emissions component'' to provide clarity that these sources of large emission events are covered.

[190] See Docket ID Item No. EPA–HQ–OAR–2010–0505–7632, Chapter 4, page 4–319.

''Fugitive emissions component'' is proposed to be any component that has the potential to emit fugitive emissions of methane and VOC at a well site or compressor station, including valves, connectors, PRDs, open-ended lines, flanges, all covers and closed vent systems, all thief hatches or other openings on a controlled storage vessel, compressors, instruments, meters, natural gas-driven pneumatic controllers or natural gas-driven 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. This proposed definition includes the same components that were included in the 2016 NSPS OOOOa and adds sources of large emissions, such as malfunctioning controllers or control devices.

The inclusion of specific component types in this proposed definition would allow the use of OGI, EPA Method 21, or an alternative screening technology to identify emissions that would either be repaired (*i.e.,* leaks) or have a root cause analysis with corrective action (*e.g.,* malfunctioning control device, unintentional gas carry through, venting from covers and openings on a controlled storage vessel, or malfunctioning natural gas-driven pneumatic controllers). Further, we are proposing that where a CVS is used to route emissions from an affected facility (*i.e.,* centrifugal or reciprocating compressor, pneumatic pump, or storage vessel), the owner or operator would demonstrate there are no detectable emissions from the covers and CVS through the OGI (or EPA Method 21) monitoring conducted during the fugitive emissions survey. Where emissions are detected, corrective actions to complete all necessary repairs as soon as practicable would be required, and the emissions would be considered a potential violation of the no detectable emissions standard. In the case of a malfunction or operational upset of a control device or the equipment itself, where emissions are not expected to occur if the equipment is operating in compliance with the standards of the rule, this proposal would require the owner or operator to conduct a root cause analysis to determine why the emissions are present, take corrective action to complete all necessary repairs as soon as practicable and prevent reoccurrence of emissions, and report the malfunction or operational upset as a potential violation of the underlying standards for the source of the emissions. We are soliciting comment on whether to include the option to continue utilizing monthly AVO surveys as demonstrations of no detectable emissions from a CVS but are not proposing that option specifically. Because the EPA is proposing both NSPS and EG in this action, we anticipate that CVS associated with controlled pneumatic pumps will be located at well sites subject to fugitive emissions monitoring. Therefore, we do not believe the monthly AVO option is necessary. However, we are soliciting comment on whether there are circumstances where a CVS associated with a controlled pneumatic pump is located at a well site not otherwise subject to fugitive emissions monitoring and where OGI (or EPA Method 21) would be an additional burden.

The EPA is soliciting comment on this proposed definition of ''fugitive emissions component,'' including any additional components or characterization of components that should be included. Further, we are soliciting comment on the use of the fugitive emissions survey to identify malfunctions and other large emission sources where the equipment is not operating in compliance with the underlying standards, including the proposed requirement to perform a root cause analysis and to take corrective action to mitigate and prevent future malfunctions.

2. Fugitive Emissions From Well Sites

The current NSPS for reducing fugitive VOC and methane emissions at well sites requires semiannual monitoring, except that a low production well site (one that produces at or below 15 barrels of oil equivalent (boe) per day) is exempt from VOC monitoring. As explained in section X.A.1, we are proposing to remove that exemption from NSPS OOOOa, as we have concluded that exemption was not justified by the underlying record and does not represent BSER. Further, based on our revised BSER analysis, which is summarized in section XII.A.1.a, the EPA is proposing updated standards for reducing fugitive VOC and methane emissions from the collection of fugitive emissions components located at new, modified, or reconstructed well sites (under the newly proposed NSPS OOOOb). Also, for the reasons discussed in section XII.A.2, the EPA is proposing to determine that the BSER analysis supports a presumptive standard for reducing methane emissions from the collection of fugitive emissions components located at existing well sites (under the newly proposed EG OOOOc) that is the same as what we are proposing for the NSPS (for NSPS OOOOb). Provided below is a summary of the proposed updated NSPS and the proposed EG.

a. NSPS OOOOb

For new, modified, or reconstructed sources, we are proposing a fugitive emissions monitoring and repair program that includes monitoring for fugitive emissions with OGI in accordance with the proposed 40 CFR part 60, appendix K (''appendix K''), which is included in this action and outlines the proposed procedures that must be followed to identify emissions using OGI.[191] We are also proposing that EPA Method 21 may be used as an alternative to OGI monitoring. We are further proposing that monitoring must begin within 90 days of startup of production (or startup of production after modification).

Unlike in NSPS OOOOa which, as amended by the 2020 Technical Rule, set VOC monitoring frequency based on production level, the EPA is proposing that the OGI monitoring frequency be based on the site-level methane baseline emissions,[192] as determined, in part, through equipment/component count emission factors. The EPA is proposing the calculation of the total site-wide methane emissions, including fugitive emissions from components, emissions from natural gas-driven pneumatic controllers, natural gas-driven pneumatic pumps, storage vessels, as well as other regulated and non-regulated emission sources. Specifically, we are proposing that owners or operators would calculate the site-level baseline methane emissions using a combination of population-based emission factors and storage vessel emissions. Further, the EPA proposes this calculation would be repeated every time equipment is added to or removed from the site. For each natural gas-driven pneumatic pump, continuous bleed natural gas-driven pneumatic

[191] ''Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging'' located at Docket ID No. EPA–HQ–OAR–2021–0317.

[192] As shown in the TSD, the EPA analyzed the monitoring frequency for both methane and VOC under both the single pollutant approach and the multipollutant approach. Because the composition of gas at a well site is predominantly methane (approximately 70 percent), a methane threshold represents the lowest threshold that is cost effective to control both VOC and methane emissions.

controller, and intermittent bleed natural gas-driven pneumatic controller located at the well site, the owner or operator would apply the population emission factors for all components found in Table W–1A of GHGRP subpart W. For each piece of major production and processing equipment and each wellhead located at the well site, the owner or operator would first apply the default average component counts for major equipment found in Table W–1B and Table W–1C of GHGRP subpart W, and then apply the component-type emission factors for the population of valves, connectors, open-ended lines, and PRVs found in Table 2–8 of the 1995 Emissions Protocol.[193] Finally, the owner or operator would use the calculated potential methane emissions after applying control (if applicable) for each storage vessel tank battery located at the well site. The sum of the emissions estimated for all equipment at the site would be used as the baseline methane emissions for determining the applicable monitoring frequency. The EPA proposes to use the default population emission factors found in Table W–1A of GHGRP subpart W and the default average component counts for major equipment found in Tables W–1B and W–1C of GHGRP subpart W because they are well-vetted emission and activity factors used by the Agency. The EPA is not incorporating these emission factors directly into the proposed NSPS OOOOb or EG OOOOc because they could be the subject of future GHGRP subpart W revisions, and if revised, those revisions would be relevant to this calculation. For the individual components (*e.g.,* valves and connectors), the EPA proposes to rely on the component-type emission factors found in Table 2–8 of the 1995 Emissions Protocol for purposes of quantifying emissions from major production and processing equipment and each wellhead located at the well site because these data have been relied upon in previous rulemakings for this sector, have been the subject of extensive public comment, and the EPA has determined that they are appropriate to use for purposes of this action.

The EPA requests comment on whether the proposed methodologies for calculating site-level baseline methane emissions are appropriate for these emission sources, and if not, what methodologies would be more appropriate. Specifically, the EPA recognizes the proposed calculation methodology assumes all equipment is operating as designed (*e.g.,* controlled storage vessels with all vapors routed to a control that is actually achieving 95 percent reduction or greater). Therefore, we are soliciting comment on whether sites should use the uncontrolled PTE calculation for their storage vessels in their site-level baseline estimate to account for times when these vessels are not operating as designed, which is a known cause of large emission events of concern. Further, to that point, the EPA is soliciting comment on how to develop a factor that could be applied to the site-level baseline calculation that would account for large emission events, or any specific data that would provide a factor for these events. As we state throughout this preamble, large emission events are of specific concern and fugitive emissions monitoring is an effective tool for detecting these emissions, therefore, we acknowledge there is considerable interest from various stakeholders that these emission events are accounted for in our analyses. At this time, the EPA does not have enough information to develop a factor or determine how to best apply that factor. Information provided through this solicitation would allow us to consider additional revisions to this calculation methodology through a supplemental proposal.

The EPA is also soliciting comment on whether providing direct major equipment population emission factors that can be combined with site-specific gas compositions would provide a more transparent and less burdensome means to develop the site-specific emissions estimates than using a combination of major equipment counts, specific component counts per major equipment, and component-level population emission factors. Furthermore, the EPA requests comment on whether site-level baseline methane emissions should be determined using a baseline emissions survey instead of the proposed methodology, and if so, what methodologies should be used to quantify emissions from the survey such as measurement or emission factors based on leaking component emission factors. The EPA also solicits comment on specific methodologies to support commenters' positions. The EPA also requests comment on whether there are additional production and processing equipment or emission sources that should be included in the site-level baseline methane emissions. For example, the EPA is aware that there could be emission sources such as engines, dehydrator venting, compressor venting, associated gas venting, and migration of gas outside of the wellbore at a well site. If such equipment or emission sources should be included in the site-level baseline, the EPA requests comment on methodologies for quantifying emissions for purposes of the baseline.

Based on the analysis described in section XII.A.1, the potential for fugitive emissions is impacted more by the number and type of equipment at the site, and not by the volume of production. Therefore, the EPA believes it is more appropriate to use site-specific emissions estimates based on the number and type of equipment located at the individual site to determine the monitoring frequency. Table 13 summarizes the proposed site-level baseline methane thresholds for the proposed monitoring frequencies, which according to our analysis would achieve the greatest cost-effective emission reductions.

As noted below, the EPA solicits comment on all aspects of the proposed tiered approach to monitoring that is summarized in Table 13. Although we are proposing no routine OGI monitoring where site-level baseline methane emissions are below 3 tpy, the EPA is proposing to require these sites to demonstrate the actual emissions are accounted for in the calculation. This demonstration would include a survey, such as OGI, EPA Method 21 (including provisions for the use of a soap solution), or advanced measurement technologies. Given that this demonstration is designed to show actual emissions are below 3 tpy, and most survey techniques are not quantitative, the EPA anticipates that sources finding emissions will make repairs on equipment/components identified as leaking during the demonstration survey.

The EPA acknowledges that the 2016 NSPS OOOOa and this proposal allow the use of EPA Method 21 as an alternative to OGI monitoring to detect fugitive emissions from the collection of fugitive emissions components under the proposed tiered approach to monitoring. However, as discussed in section XI.A.5, EPA Method 21 is not proposed as an alternative for follow-up OGI surveys under the proposed alternative screening approach using advanced measurement technologies when screening detects emissions. This is because EPA Method 21 is not able to find all sources of leaks and is therefore not an appropriate method for detection in these cases where large emissions events have been identified. Given this limitation, the EPA is soliciting comment on whether EPA Method 21 remains an appropriate

[193] EPA, Protocol for Equipment Leak Emission Estimates, EPA–453/R–95–017, November 1995.

alternative to OGI for routine OGI surveys.

TABLE 13—PROPOSED WELL SITE MONITORING FREQUENCIES BASED ON SITE–LEVEL BASELINE METHANE EMISSIONS

Site-level baseline methane emissions threshold	Proposed OGI monitoring frequency	Co-proposed OGI monitoring frequency
>0 and <3 tpy	No routine monitoring required	No routine monitoring required.
≥3 and <8 tpy	Quarterly	Semiannual.
≥8 tpy	Quarterly	Quarterly.

Where quarterly monitoring is proposed, subsequent quarterly monitoring would occur at least 60 days apart. Where semiannual monitoring is co-proposed, subsequent semiannual monitoring would occur at least 4 months apart and no more than 7 months apart. We are proposing to retain 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.

The EPA has previously required the use of OGI technology to detect fugitive emissions of methane and VOC from the oil and gas sector (*i.e.,* well sites and compressor stations). However, the EPA had not developed a protocol for its use even though the EPA has previously mentioned the need for an OGI protocol during other rulemakings where OGI has been proposed for leak detection.[194] In this document, the EPA is proposing a draft protocol for the use of OGI as appendix K to 40 CFR part 60. The EPA notes that while this protocol is being proposed for use in the oil and gas sector, the applicability of the protocol is broader. The protocol is applicable to surveys of process equipment using OGI cameras in the entire oil and gas upstream and downstream sectors from production to refining to distribution where a subpart in those sectors references its use.

As part of the development of appendix K, the EPA conducted an extensive literature review on the technology development as well as 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.[195]

Appendix K outlines the proposed procedures that instrument operators must follow to identify leaks or fugitive emissions using a hand-held, field portable infrared camera. Additionally, appendix K contains proposed specifications relating to the required performance of qualifying infrared cameras, required operator training and verification, determination of an operating window for performing surveys, and requirements for a monitoring plan and recordkeeping. The EPA is requesting comment on all aspects of the draft OGI protocol being proposed as appendix K to 40 CFR part 60.[196]

As mentioned in section X.B.4.f, we are proposing that, once fugitive methane emissions are detected during the OGI survey, a first attempt at repair must be made within 30 days of detecting the fugitive emissions, with final repair, including resurvey to verify repair, completed within 30 days after the first attempt. These proposed repair requirements with respect to methane fugitive emissions are the same as those made in the 2020 Technical Rule for VOC fugitive emissions (and proposed in section X.B.4.f for methane in this action). Because large emission events contribute disproportionately to emissions, the EPA is soliciting comment on how to structure a requirement that would tier repair deadlines based on the severity of the fugitive emissions identified during the OGI (or EPA Method 21) surveys. In order for such a structure to work, there would need to be a way to qualify which fugitive emissions are smaller and which are larger, as the initial monitoring with OGI will not provide this information. One approach could be to define broad categories of leaks and make assumptions about the magnitude of emissions for those broad categories. For example, an open thief hatch would be considered a very large leak due to the surface opening size, and it would need to be remedied on the tightest timeframe, whereas a leaking connector would be considered a small leak based on historical emissions factors and could be repaired on a more lenient timeframe. The EPA is soliciting comments on how this approach could be structured, particularly the types of leaks that would fall into each broad category and the appropriate repair timeframes for each of the categories. The EPA is also soliciting comment on other approaches that could also be implemented for repairing fugitive emissions in a tiered structure. Finally, we are proposing to retain the requirement for owners and operators to develop a fugitive emissions monitoring plan that covers all the applicable requirements for the collection of fugitive emissions components located at a well site and includes the elements specified in the proposed appendix K when using OGI.

The affected facilities include well sites with major production and processing equipment, and centralized tank batteries. As in the 2020 Technical Rule, the EPA is proposing to not include ‘‘wellhead only well sites,’’ as affected facilities when the well site is a wellhead only well site at the date it becomes subject to the rule. Based on the proposed site-level baseline methane emissions calculation methodology, wellhead only sites would only calculate emissions from fugitive components (*e.g.,* valves, connectors, flanges, and open-ended lines) that are located on the wellhead. We believe

[194] The development of appendix K to 40 CFR part 60 was previously mentioned in both the proposal for the National Uniform Emission Standards for Storage Vessel and Transfer Operations, Equipment Leaks, and Closed Vent Systems and Control Devices; and Revisions to the National Uniform Emission Standards General Provisions (77 FR 17897, March 26, 2012) and the Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards (79 FR 36880, June 30, 2014).

[195] *Technical Support Document—Optical Gas Imaging Protocol (40 CFR part 60, Appendix K),* available in the docket for this action.

[196] See appendix K in Docket ID No. EPA–HQ–OAR–2021–0317.

these sites would not exceed the 3 tpy threshold to require routine monitoring. However, unlike the 2020 Technical Rule, the EPA is proposing that when a well site later removes all major production and processing equipment such that it becomes a wellhead only well site, it must recalculate the emissions in order to determine if a different frequency is then required. In this proposal, the definitions for ''wellhead only well site'' and ''well site'' would be the same as those finalized in the 2020 Technical Rule. Specifically, ''wellhead only well site'' means ''for purposes of the fugitive emissions standards, a well site that contains one or more wellheads and no major production and processing equipment.'' The term ''major production and processing equipment'' refers to ''reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water.'' The EPA is soliciting comment on whether any other equipment not included in this definition should be added in order to clearly specify what well sites are considered wellhead only sites. Specifically, the EPA is soliciting comment on the inclusion of natural gas-driven pneumatic controllers, natural gas-driven pneumatic pumps, and pumpjack engines in the definition of ''major production and processing equipment.'' A ''well site'' means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards, a well site includes a centralized production facility. Also, for purposes of the fugitive emissions standards, a well site does not include: (1) UIC Class II oilfield disposal wells and disposal facilities; (2) UIC Class I oilfield disposal wells; and (3) the flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange.

In addition to retaining the above definitions, the EPA is also proposing a new definition for ''centralized production facility'' for purposes of fugitive emissions requirements for well sites, where a ''centralized tank battery'' is one or more permanent storage tanks and all equipment at a single stationary source 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. Additional discussion on centralized production facilities is included in section XI.L.

The EPA is not proposing any change to the current definition of modification as it relates to fugitive emissions requirements at well sites or centralized production facilities. Specifically, modification occurs at a well site when: (1) A new well is drilled at an existing well site; (2) a well at an existing well site is hydraulically fractured; or (3) a well at an existing well site is hydraulically refractured. Similarly, modification occurs at a centralized production facility when (1) any of the actions above occur at an existing centralized production facility; (2) a well sending production to an existing centralized production facility is modified as defined above for well sites; or (3) a well site subject to the fugitive emissions standards for new sources removes all major production and processing equipment such that it becomes a wellhead only well site and sends production to an existing centralized production facility.

b. EG OOOOc

For existing well sites (for EG OOOOc), we are proposing a presumptive standard that follows the same fugitive monitoring and repair program as for new sources. For the reasons discussed in section XII.A.2, the BSER analysis for existing sources supports proposing a presumptive standard for reducing methane emissions from the collection of fugitive emissions components located at existing well sites that is the same as what the EPA is proposing for new, reconstructed, or modified sources (for NSPS OOOOb). 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. The EPA determined that the OGI technology, methane emission reductions, costs, and cost effectiveness discussed above for the collection of fugitive emissions components at new well sites are also applicable for the collection of fugitive emissions components 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 found is appropriate to use the analysis developed for the proposed NSPS OOOOb to also develop the BSER and proposed presumptive standards for the EG OOOOc.

Based on the information available at this time, the EPA thinks the large number of existing well sites, many of which are not complex warrants soliciting comment on whether existing well sites (or a subcategory thereof) could have different emission profiles due to certain site characteristics or other factors that would suggest a different presumptive standard is appropriate. Further, we remain concerned about the burden of fugitive emissions monitoring requirements on small businesses. Therefore, we are requesting comment on regulatory alternatives for well sites that accomplish the stated objectives of the CAA and which minimize any significant economic impact of the proposed rule on small entities, including any information or data that pertain to the emissions impacts and costs of our proposal to remove the exemption from fugitive monitoring for well sites with low emissions, or would support alternative fugitive monitoring requirements for these sites. We are soliciting data that assess the emissions from low production well sites, and information on any factors that could make certain well sites less likely to emit VOC and methane, including geologic features, equipment onsite, production levels, and any other factors that could establish the basis for appropriate regulatory alternatives for these sites. Further, the EPA is aware there are a subset of existing well sites that are owned by individual homeowners, farmers, or companies with very few employees (well below the threshold defining a small business). For these owners, the EPA is concerned our analysis underestimates the actual burden imposed by these proposed standards. As an example, ownership may be limited to 1 or 2 wells located on an individual's property, for which the production is used for heating the home. The cost burden of conducting fugitive emissions surveys in this type of scenario has not fully be analyzed. Therefore, the EPA solicits comment and information that would allow us to further evaluate the burden on the smallest companies to further propose appropriate standards at this subset (or other similar subsets) of well sites through a supplemental proposal.

Finally, we are soliciting comment on all aspects of the proposed fugitive emissions requirements for both new and existing well sites, including whether we should use the tiering approach, whether the tiers we have defined are appropriate, and the monitoring requirements for each tier, including whether it would be cost-effective to monitor at more frequent intervals than proposed. The EPA may include revisions to this proposal for ground-based OGI monitoring at well sites if information is received that would warrant consideration of a different approach to establishing monitoring frequencies at well sites.

3. Fugitive Emissions from Compressor Stations

The current NSPS for reducing fugitive emissions from the collection of fugitive emissions components located at a compressor station is a fugitive emissions monitoring and repair program requiring quarterly OGI monitoring.[197] Based on our analysis, which is summarized in section XII.A.1.b, the EPA is proposing quarterly OGI monitoring requirement for both methane and VOC as it continues to reflect the BSER for reducing both emissions from fugitive components at new, modified, and reconstructed compressor stations. Likewise, the EPA is also proposing quarterly monitoring as a presumptive GHG standard (in the form of limitation on methane emissions) for the collection of fugitive emissions components located at existing compressor stations. The affected compressor stations include gathering and boosting, transmission, and storage compressor stations.

a. NSPS OOOOb

We are proposing that the quarterly monitoring using OGI be conducted in accordance with the proposed appendix K described above in section XI.A.2, which outlines procedures that must be followed to identify leaks using OGI. We are proposing to retain the current requirements that monitoring must begin within 90 days of startup of the station (or startup after modification), with subsequent quarterly monitoring occurring at least 60 days apart. Also, quarterly monitoring may be waived when temperatures are below 0 °F for two of three consecutive calendar months of a quarterly monitoring period. We are also not proposing any change to the following repair-related requirements: Specifically, a first attempt at repair must be made within 30 days of detecting the fugitive emissions, with final repair, including resurvey to verify repair, completed within 30 days after the first attempt. In addition, owners and operators must develop a fugitive emissions monitoring plan that covers all the applicable requirements for the collection of fugitive emissions components located at a compressor station. In conjunction with the proposed requirement that monitoring be conducted in accordance with the proposed appendix K, we are proposing to require that the monitoring plan also include elements specified in the proposed appendix K when using OGI.

b. EG OOOOc

For existing sources, we are proposing a presumptive standard that includes the same fugitive emissions monitoring and repair program as for new sources. For the reasons discussed in section XII.A.2, the BSER analysis for existing sources supports proposing a presumptive standard for reducing methane emissions from the collection of fugitive emissions components located at existing compressor stations that is the same as what the EPA is proposing for new, modified, or reconstructed sources (for NSPS OOOOb).

Similar to well sites, we are soliciting comment on all aspects of the proposed quarterly monitoring for both new and existing compressor stations, including whether more frequent monitoring would be appropriate. We are also soliciting information on several additional topics. First, the EPA is soliciting comment and data to assess whether compressor stations should be subcategorized for the NSPS and/or the EG, which the EPA could consider through a supplemental proposal. For example, some industry stakeholders have asserted that station throughput directly correlates to the operating pressures, equipment counts, and condensate production, which would influence fugitive emissions at the station. They suggested that subcategorization based on design throughput capacity for the compressor station may be appropriate. We are specifically seeking information related to throughputs where fugitive emissions of methane are demonstrated to be minimal below a certain capacity. While this specific example was raised in the context of existing sources only, the EPA is also soliciting comment on whether new, modified, or reconstructed compressor stations could encounter the same issue and therefore warrant similar subcategorization.

Next, for compressor stations, we are soliciting comment on delayed repairs by existing sources when parts are not readily available and must be special ordered. In comments submitted to the EPA as part of the stakeholder outreach conducted prior to this proposal, industry stakeholders stated that the EPA "should acknowledge that existing sources are older pieces of equipment so there is a higher likelihood that replacement parts will not be readily available; therefore, a lack of available parts should be an appropriate cause to delay a repair."[198] Industry stakeholders further explained that operators will need to special order replacement parts. Further, they stated in their comments that operators should be afforded 30 days to schedule the repair once they have received the replacement part. The EPA is soliciting comment and data to better understand the breadth of this issue with replacement parts for existing compressor stations. Additionally, we are soliciting comment on whether 30 days following receipt of the replacement part is appropriate for completing delayed repairs at existing compressor stations, whether there should be any limit on delays in repairs under these circumstances, and whether this compliance flexibility should be limited or disallowed based on the severity of the leak to be repaired.

We are also soliciting comment on the specific records that should be maintained and/or reported to justify delayed repairs as a result of part availability issues. Depending on the additional information received, the EPA may consider proposing changes to the proposed EG for compressor stations through a supplemental proposal.

Finally, as discussed in section XI.A.2, the EPA is soliciting comment on whether the scheduling of repairs at compressor stations should be tiered based on severity of the emissions found. Please refer to section XI.A.3 for additional details on this solicitation for comment.

4. Well Sites and Compressor Stations on the Alaska North Slope

For new, reconstructed, and modified well sites and compressor stations

[197] Note that for gathering and boosting compressor stations, the EPA is proposing to rescind the 2020 Technical Rule amendment that changed the monitoring frequency to semiannual for VOC emissions. See section X.A.2 for more information.

[198] Document ID No. EPA–HQ–OAR–2021–0295–0033.

located on the Alaska North Slope, based on the rationale provided in section X.B.4.c of this preamble, the EPA is proposing the same monitoring requirements as those in NSPS OOOOa (under newly proposed OOOOb). Also, the EPA is proposing to determine that the same technical infeasibility issues with weather conditions exist for existing well sites and compressor stations located on the Alaska North Slope. Therefore, the EPA is proposing a presumptive standard for reducing methane emissions from the collection of fugitive emissions components located at existing well sites and compressor stations located on the Alaska North Slope (under the newly proposed EG OOOOc) that is the same as what we are proposing for NSPS OOOOb.

Specifically, the EPA is proposing to require annual monitoring of methane and VOC emissions at all well sites and compressor stations located on the Alaska North Slope, with subsequent annual monitoring at least 9 months apart but no more than 13 months apart. The EPA is also proposing to require that new, reconstructed, and modified well sites and compressor stations located on the Alaska North Slope that startup (initially, or after reconstruction or modification) between September and March to conduct initial monitoring of methane and VOC fugitive emissions within 6 months of startup, or by June 30, whichever is later. Finally, the EPA is proposing to require that new, reconstructed, and modified well sites and compressor stations located on the Alaska North Slope that startup (initially, or after reconstruction or modification) between April and August to conduct initial monitoring of methane and VOC fugitive emissions within 90 days of startup.

5. Alternative Screening Using Advanced Measurement Technologies

For new, modified, or reconstructed sources (*i.e.,* collection of fugitive emissions components located at well sites and compressor stations), the EPA is proposing an alternative fugitive emissions monitoring and repair program that includes bimonthly screening for large emission events using advanced measurement technologies followed with at least annual OGI in accordance with the proposed 40 CFR part 60, appendix K (''appendix K''), which is included in this action and outlines the proposed procedures that must be followed to identify emissions using OGI.[199] Additionally, we are proposing this same alternative screening using advanced measurement technologies as an alternative presumptive standard for existing sources.

Specifically, the EPA is proposing to allow owners and operators the option to comply with this alternative fugitive emissions standard instead of the proposed ground based OGI surveys summarized in sections XI.A.2 and XI.A.3. The EPA proposes to require owners and operators choosing this alternative standard to do so for all affected well sites and compressor stations within a company-defined area. This company-defined area could be a county, sub-basin, or other appropriate geographic area. Under this proposed alternative, the EPA proposes to require a screening survey on a bimonthly basis using a methane detection technology that has been demonstrated to achieve a minimum detection threshold of 10 kg/hr. This screening survey would be used to identify individual sites (*i.e.,* well sites and compressor stations) where a follow-up ground-based OGI survey of all fugitive emissions components at the site is needed because fugitive emissions have been detected. Given the proposed minimum detection threshold of 10 kg/hr, which would constitute a significant emissions event, the EPA believes this follow-up OGI survey should be completed in an expeditious timeframe, therefore we are proposing to require this follow-up OGI survey of all fugitive emissions components at the site within 14 days of the screening survey. However, additional information is needed to fully evaluate the appropriateness of this deadline. Therefore, the EPA is soliciting comment on the proposed 14-day deadline for a follow-up OGI survey and information that would allow further evaluation of other potential deadlines to require.

Next, for sites with emissions identified during screening and subject to this follow-up OGI survey, the EPA proposes that any fugitive emissions identified must be repaired, including those emissions identified during the screening survey. For purposes of this proposal, the EPA is proposing the same repair deadlines as those for the ground based OGI requirements discussed in sections XI.A.2 and XI.A.3, which are a first attempt at repair within 30 days of the OGI survey and final repair completed within 30 days of the first attempt. As noted in section XI.A.1, some equipment types with large emissions warrant a requirement for root cause analysis rather than simply repairing the emission source. The EPA solicits comment on how that root cause analysis with corrective action approach could be applied in this proposed alternative screening approach. Further, because large emission events, especially those identified during the screening surveys, contribute disproportionately to emissions, the EPA is also soliciting comment on how to structure a requirement that would tier repair deadlines based on the severity of the fugitive emissions when using this proposed alternative standard. See section XI.A.2 for additional discussion of this solicitation on tiered repairs.

In addition to the bimonthly screening surveys proposed above, the EPA recognizes that component-level fugitive emissions may still be present at sites where the screening survey does not detect emissions. Therefore, in conjunction with these bimonthly screenings performed with the advanced measurement technology, the EPA is proposing to require a full OGI (or EPA Method 21) survey at least annually at each individual site utilizing the alternative screening standard. If the owner or operator performs an OGI survey in response to emissions found during the bimonthly screening survey, that OGI survey would count as the annual OGI survey; a second survey would not be required to comply with the annual OGI survey requirement and the clock would restart with the next annual survey due within 12 calendar months. The overall purpose of this annual OGI survey is to ensure that each individual site is surveyed with OGI at least annually, even where large emissions are not detected during the screening surveys using advanced measurement technology. The EPA is not allowing EPA Method 21 for use during the proposed follow-up OGI surveys when screening detects emissions because EPA Method 21 is not appropriate for detecting the sources of large emission events, such as malfunctioning control devices.

Finally, the EPA is proposing to require that owners and operators include information specific to the alternative standard within their fugitive emissions monitoring plan. Since the 2016 NSPS OOOOa, owners and operators have been required to develop and maintain a fugitive emissions monitoring plan for all sites subject to the fugitive emissions requirements. This monitoring plan includes information regarding which sites are covered under the plan, which technology is being used (*e.g.,* OGI or EPA Method 21), and site or company-

[199] ''Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging'' located at Docket ID No. EPA–HQ–OAR–2021–0317.

specific procedures that are employed to ensure compliant surveys. The EPA is proposing to add a requirement that the monitoring plan also address sites that are utilizing the proposed alternative standard. Specifically, the EPA is proposing a requirement to include the following information when the alternative standard is applied:

• Identification of the sites opting to comply with the alternative screening approach;

• General description of each site to be monitored, including latitude and longitude coordinates of the asset in decimal degrees to an accuracy and precision of five decimals of a degree using the North American Datum of 1983;

• Description of the measurement technology;

• Verification that the technology meets the 10 kg/hr methane detection threshold, including supporting data to demonstrate the sensitivity of the measurement technology as applied;

• Procedures for a daily verification check of the measurement sensitivity under field conditions (*e.g.,* controlled releases);

• Standard operating procedures consistent with EPA's guidance [200] and to include safety considerations, measurement limitations, personnel qualification/responsibilities, equipment and supplies, data and record management, and quality assurance/quality control (*i.e.,* initial and ongoing calibration procedures, data quality indicators, and data quality objectives); and

• Procedures for conducting the screening.

In the event that an owner or operator uses multiple technologies covered by one monitoring plan, the owner or operator would identify which technology is to be used on which site within the monitoring plan.

In addition to the proposed requirements within the monitoring plan, the EPA is also proposing specific recordkeeping and reporting requirements associated with the follow-up OGI surveys that are consistent with the recordkeeping and reporting required for OGI surveys in NSPS OOOOa as amended in the 2020 Technical Rule. See section X.B.1.h and X.B.1.i. The EPA is soliciting comment on when notifications would be required for sites where the alternative standard is applied. Further, the EPA is soliciting comment on whether submission of the monitoring plan, and/or Agency approval before utilizing the alternative standard is necessary to ensure consistency in screening survey procedures in the absence of finalized methods or procedures.

While the EPA is proposing the above alternative screening requirements, additional information is necessary to further refine the specific alternative work practice as it relates to the available technologies. Specific information is requested in the following paragraphs, and, if received, would allow the EPA to better analyze the BSER for fugitive emissions at well sites and compressor stations through a supplemental proposal.

First, the EPA solicits comment on the use of 10 kg/hr as the minimum detection threshold for the advanced measurement technologies used in the alternative screening approach, including data that would support consideration of another detection threshold. The EPA also solicits comment on whether a matrix approach should be developed, instead of prescribing one detection threshold and screening frequency, and what that matrix should look like. In the matrix approach, the frequency of the screening surveys and regular OGI (or EPA Method 21) surveys would be based on the sensitivity of the technology, with the most sensitive detection thresholds having the least frequent screening and survey requirements and the least sensitive detection thresholds having the most frequent screening and survey requirements. For example, sites that are screened using a technology with a detection threshold of 1 kg/hr may require less frequent screening and may require an OGI survey less frequently than sites screened using a technology with a detection threshold of 50 kg/hr. We are also soliciting comment on the detection sensitivity of commercially available methane detection technologies based on conditions expected in the field, as well as factors that affect the detection sensitivity and how the detection sensitivity would change with these factors.

Next, the EPA is soliciting comment on the standard operating procedures being used for commercially available technologies, including any manufacturer recommended data quality indicators and data quality objectives in use to validate these measurements. Additionally, for those commercially available technologies that quantify methane emissions rather than just detect methane, we are soliciting comment on the range of quantification based on conditions one would expect in the field.

The EPA is seeking information that would allow us to further evaluate the potential costs and assumed emission reductions achieved through an alternative screening program. Therefore, the EPA is seeking information on the cost of screening surveys using different types of advanced measurement technologies, singularly or in combination, and factors that affect that cost (*e.g.,* is it influenced by the number of sites and length of survey). Additionally, we are interested in understanding whether there would be opportunities for cost-sharing among operators and whether any aspect of regulation would be beneficial or required to facilitate such cost-sharing opportunities. We also solicit comment on whether these technologies and cost-sharing opportunities would allow for cost-effective monitoring at all sites owned or operated by the same company within a sub-basin or other discrete geographic area. Further, we seek comment on the current and expected availability of these advanced measurement technologies and the supporting personnel and infrastructure required to deploy them, how their cost and availability might be affected if demand for these technologies were to increase, and how quickly the use of these technologies could expand if they were integrated into this regulatory program either as a required element of fugitive monitoring or as this proposed alternative work practice.

The EPA recognizes that the approach outlined above may not be suited to continuous monitoring technologies, such as network sensors or open-path technology. While these systems typically have the ability to meet the 10 kg/hr methane threshold discussed above [201] the emissions from these well sites can be intermittent or tied to process events (*e.g.,* pigging operations). We are concerned that the proposed alternative screening approach would trigger an OGI survey for every emission event, regardless of type, duration, or size, if a continuous monitoring technology is installed. This would disincentivize the use of continuous monitoring systems, which could be valuable tools in finding large emission sources sooner. While we believe that a framework for advanced measurement technologies that monitor sites continuously should be developed, we do not currently have all of the information that is necessary to develop

[200] Guidance for Preparing Standard Operating Procedures (SOPs), EPA/600/B–07/001, April 2007, *https://www.epa.gov/sites/default/files/2015-06/documents/g6-final.pdf.*

[201] Alden et al., Single-Blind Quantification of Natural Gas Leaks from 1 km Distance Using Frequency Combs, *Environmental Science and Technology,* 2019, *53,* 2908–2917.

an equivalence demonstration for these monitors or to ensure the technology works appropriately over time. Therefore, we are soliciting comment on how an equivalence demonstration can be made for these continuous monitoring technologies.

The framework for a continuous monitoring technology would need to cover the following items at a minimum: The number of monitors needed and the placement of the monitors; minimum response factor to methane; minimum detection level; frequency of data readings; how to interpret the monitor data to determine what emissions are a detection versus 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. We are soliciting comment on how to develop a framework that is flexible for multiple technologies while still ensuring that emissions are adequately detected and the monitors respond appropriately over time. Additionally, we are soliciting comment on whether these continuous monitors need to respond to other compounds as well as methane; how close a meteorological station must be to the monitored site; and whether OGI or EPA Method 21 surveys should still be required, and if so, at what frequency.

At this time, the EPA does not have enough information to determine how this proposed alternative standard using advanced measurement technologies compares to the proposed BSER of OGI monitoring at well sites at a frequency that is based on the site baseline methane emissions as described in section XI.A.3.a, or to quarterly OGI monitoring at compressor stations. Information provided through this solicitation may be used to reevaluate BSER through a supplemental proposal.

6. Use of Information From Communities and Others

As the EPA learned during the Methane Detection Technology Workshop, 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, source of, and factors that lead to large emission events. The EPA anticipates that the use of these techniques by a variety of parties, including communities located near oil and gas facilities or affected by oil and gas pollution, will continue to grow as these technologies become more widely available and decline in cost.

The EPA is seeking comment on how to take advantage of the opportunities presented by the increasing use of these technologies to help identify and remediate large emission events (commonly known as ''super-emitters''). Specifically, the EPA seeks comment on how to evaluate, design, and implement a program whereby communities and others could identify large emission events and, where there is credible information of such a large emission event, provide that information to owners and operators for subsequent investigation and remediation of the event. The EPA understands that these large emission events are often attributable to malfunctions or abnormal process conditions that should not be occurring at a well-operating, well-maintained, and well-controlled facility that has implemented the various BSER measures identified in this proposal.

We generally envision a program for finding large emission events that consists of a requirement that, if emissions are 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.

We seek comment on all aspects of this concept, which would be developed further as part of a supplemental proposal. Among other things, the EPA is soliciting comment on an emissions threshold that could be used to define these large emission events, and which types of technologies would be suitable for identification of large emissions events. For example, there are some satellite systems capable of generally identifying emissions above 100 kg/hr with a spatial resolution which could allow identification of emission events from an individual site.[202] Additionally there are other satellites systems available which have wider spatial resolution that can identify large methane emission events, and when combined with finer resolution platforms, could allow identification of emission events from an individual site. The EPA believes that any emissions visible by satellites should qualify as large emission events. However, the EPA solicits comment on whether the threshold for a large emission should be lower than what is visible by satellite.

Second, in order to make this approach viable, the EPA would need to specify what actions an owner or operator must take when notified of a large emission event, including deadlines for taking such actions. These elements could include the specific steps the company would take to investigate the notification and mitigate the event, such as verifying the location of the emissions, conducting ground investigations to identify the specific emission source, conducting a root cause analysis, performing corrective action within a specific timeframe to mitigate the emissions, and preventing ongoing and future chronic or intermittent large emissions from that source. These steps could be incorporated into a fugitive emissions monitoring plan maintained by the owner or operator, and failure to take the actions specified by the owner or operator in the plan could be considered noncompliance. We seek comment on what specific follow-up actions or other procedures would be appropriate to require once a large emission event is identified, as well as appropriate deadlines for these actions.

Third, the EPA would need to define guidelines for credible and actionable data. The EPA is soliciting comment on what these guidelines should entail and whether specific protocols (*e.g.,* permissible detection technologies, data analytics, operator training, data reporting, public access, and data preservation) should govern the collection of such data and whether such data should conform to any type of certification. If specific certification or protocols are necessary, the EPA is soliciting comment on how that certification should be obtained.

Fourth, we are also soliciting comment on best practices for the identification of the correct owner or operator of a facility responsible for such large emissions, since such information is necessary to halt such large-volume emission events, and how the community or other third-party should notify the owner or operator, as well as how the delegated authority should be made aware of such notification.

Finally, we are soliciting comment on whether the EPA should develop a model plan for responding to notifications that companies could adopt instead of developing company- or site-specific plans, including what

[202] D.J. Varon, J. McKeever, D. Jervis, J.D. Maasakkers, S. Pandey, S. Houweling, I. Aben, T. Scarpelli, D.J. Jacob, *Satellite Discovery of anomalously Large Methane Point Sources from Oil/Gas Production,* available at *https://doi.org/10.1029/2019GL083798, October 25, 2019.*

elements should be included in that model plan.

B. Storage Vessels

1. NSPS OOOOb

The current NSPS in subpart OOOOa for storage vessels is to reduce VOC emissions by 95 percent, and the standard applies to a single storage vessel with a potential for 6 or more tpy of VOC emissions. Based on our analysis, which is summarized in section XII.B.1, the EPA is proposing to retain the 95 percent reduction standard as it continues to reflect the BSER for reducing VOC emissions from new storage vessels. The EPA is also proposing to set GHG standards (in the form of limitations on methane emissions) for storage vessels in this action. Because the BSER for reducing VOC and methane emissions are the same, the proposed GHG standard is to reduce methane emissions by 95 percent. The EPA continues to support the capture of gas vapors from storage vessels rather than the combustion of what can be an energy-rich saleable product. We incentivize this by recognizing the use of vapor recovery as a part of the process, therefore the storage vessel emissions would not contribute to the site's potential-to-emit.

Under the current NSPS for storage vessels, an affected facility is a single storage vessel with potential VOC emissions of 6 tpy or greater. The EPA is proposing to include a tank battery as a storage vessel affected facility. The EPA proposes 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.

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. For new, modified, or reconstructed sources, 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. This is consistent with the EPA's initial determination in the 2012 NSPS OOOO that controlling VOC emissions as low as 6 tpy from storage vessels is cost-effective. The proposed standard of 95 percent reduction of methane and VOC emissions, which is the same as the current VOC standard in the 2012 NSPS OOOO and 2016 NSPS OOOOa, can be achieved by capturing and routing the emissions utilizing a cover and closed vent system that routes captured emissions to a control device that achieves an emission reduction of 95 percent, or that routes captured emissions to a process.

Finally, we are proposing specific provisions to clarify what circumstances constitute a modification of an existing storage vessel affected facility (single storage vessel or tank battery), and thus subject it to the proposed NSPS instead of the EG. The EPA is proposing that a single storage vessel or tank battery is modified when physical or operational changes are made to the single storage vessel or tank battery that result in an increase in the potential methane or VOC emissions. Physical or operational changes would be defined to include: (1) The addition of a storage vessel to an existing tank battery; (2) replacement of a storage vessel such that the cumulative storage capacity of the existing tank battery increases; and/or (3) an existing tank battery or single storage vessel that receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput (from actions such as refracturing a well or adding a new well that sends these liquids to the tank battery). The EPA is proposing to require that the owner or operator recalculate the potential VOC emissions when any of these actions occur on an existing tank battery to determine if a modification has occurred. The existing tank battery will only become subject to the proposed NSPS if it is modified pursuant to this definition of modification and its potential VOC emissions exceed the proposed 6 tpy VOC emissions threshold.

2. EG OOOOc

Based on our analysis, which is summarized in section XII.B.2, the EPA is proposing EG for existing storage vessels which include a presumptive GHG standard (in the form of limitation on methane emissions). For existing sources under the EG, the EPA is proposing to define a designated facility as an existing tank battery with potential methane emissions of 20 tpy or greater. The proposed definition of a tank battery in the EG is the same as the definition proposed for new sources; however, since the designated pollutant in the context of the EG is methane, determination of whether a tank battery is a designated facility would be based on its potential methane emissions only. Our analysis shows that it is cost effective to control an existing tank battery with potential methane emissions 20 tpy or higher. Similar to the proposed NSPS, we are proposing a presumptive standard that includes a 95 percent reduction of the methane emissions from each existing tank battery that qualifies as a designated facility. Such a standard could be achieved by capturing and routing the emissions by utilizing a cover and closed vent system that routes captured emissions to a control device that achieves an emission reduction of 95 percent, or routes emission back to a process.

C. Pneumatic Controllers

1. NSPS OOOOb

The current NSPS OOOOa regulates certain continuous bleed natural gas driven pneumatic controllers, but includes different standards based on whether the pneumatic controller is located at an onshore natural gas processing plant. If the pneumatic controller is located at an onshore natural gas processing plant, then the current NSPS requires a zero bleed rate. If the pneumatic controller is located elsewhere, then the current NSPS requires the pneumatic controller to operate at a natural gas bleed rate no greater than 6 scfh. The current NSPS does not regulate intermittent vent natural gas driven pneumatic controllers at any location.

Based on our analysis, which is summarized in section XII.C.1, the EPA is proposing pneumatic controller standards for NSPS OOOOb as follows. First, in addition to each single natural gas-driven continuous bleed pneumatic controller being an affected facility, the EPA proposes to define each natural gas-driven intermittent vent pneumatic controller as an affected facility. The EPA believes these pneumatic controllers should be covered by NSPS OOOOb because natural gas-driven intermittent devices represent a large majority of the overall population of pneumatic controllers and are responsible for the majority of emissions from these sources. We are proposing to define an intermittent vent natural gas-driven pneumatic controller as a pneumatic controller that is not designed to have a continuous bleed rate but is instead designed to only release natural gas to the atmosphere as part of the actuation cycle. This affected facility definition would apply at all sites, including natural gas processing plants.

Second, we are proposing a requirement that all controllers (continuous bleed and intermittent vent) must have a VOC and methane emission rate of zero. The proposed rule does not specify how this emission rate of zero must be achieved, but a variety of viable options are discussed in Section XII.C. including the use of pneumatic controllers that are not driven by natural gas such as 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. As noted above, the EPA is proposing that the definition of an affected facility would be each pneumatic controller that is driven by natural gas and that emits to the atmosphere. As such, pneumatic controllers that are not driven by natural gas would not be affected facilities, and thus would not be subject to the pneumatic controller requirements of NSPS OOOOb. Similarly, controllers that are driven by natural gas but that do not emit to the atmosphere would also not be affected facilities. In order to demonstrate that a particular pneumatic controller is not an affected facility, owners and operators should maintain documentation to show that such controllers are not natural gas driven such as documentation of the design of the system, and to ensure that they are operated in accordance with the design so that there are no emissions.

In both NSPS OOOO and OOOOa, there is an exemption from the standards in cases where the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety, and positive actuation. The EPA is not maintaining this exemption in the proposed NSPS OOOOb, except for in very limited circumstances explained in section XII.C. As discussed in section XII.C., the reasons to allow for an exemption based on functional need in NSPS OOOO and OOOOa were based on the inability of a low-bleed controller to meet the functional requirements of an owner/operator such that a high-bleed controller would be required in certain instances. Since we are now proposing that pneumatic controllers have a methane and VOC emission rate of zero, we do not believe that the reasons related to the use of low bleed controllers are still applicable. However, EPA is soliciting comment on whether owners/operators believe that maintaining such an exemption based on functional need is appropriate, and if so why.

The proposed rule includes an exemption from the zero-emission requirement for pneumatic controllers in Alaska at locations where power is not available. In these situations, the proposed standards require the use of a low-bleed controller instead of high-bleed controller. Further, in these situations (controllers in Alaska at location without power) the proposed rule includes the exemption that would allow the use of high-bleed controllers instead of low-bleed based on functional needs. Lastly, in these situations owners/operators must inspect intermittent vent controllers to ensure they are not venting during idle periods.

2. EG OOOOc

In this action, the EPA is proposing to define designated facilities (existing sources) analogous to the affected facility definitions described above for pneumatic controllers under the NSPS. For the reasons discussed in section XII.C.2, the BSER analysis for existing sources supports proposing presumptive standards for reducing methane emissions from existing pneumatic controllers that are the same as those the EPA is proposing for new, modified, or reconstructed sources (for NSPS OOOOb).

D. Well Liquids Unloading Operations

Well liquids unloading operations, which are currently unregulated under the NSPS OOOOa, refer to unloading of liquids that have accumulated over time in gas wells and are impeding or halting production. The EPA is proposing standards in the NSPS OOOOb to reduce methane and VOC emissions during liquids unloading operations.

1. NSPS OOOOb

We are proposing standards to reduce VOC and methane emissions from each well that conducts a liquids unloading operation. Based on our analysis, which is summarized in section XII.D.1, we are proposing a standard under NSPS OOOOb that requires owners or operators to perform liquids unloading with zero methane or VOC emissions. In the event that it is technically infeasible or not safe to perform liquids unloading with zero emissions, the EPA is proposing to require that an owner or operator establish and follow BMPs to minimize methane and VOC emissions during liquids unloading events to the extent possible.

The EPA is co-proposing two regulatory approach options to implement the rule requirements.

For Option 1, the affected facility would be defined as every well that undergoes liquids unloading. This would mean that wells that utilize a non-emitting method for liquids unloading would be affected facilities and subject to certain reporting and recordkeeping requirements. These requirements would include records of the number of unloadings that occur and the method used. 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 the proposed rule Option 1 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.

For wells that utilize methods that vent to the atmosphere, the proposed rule would require that owners or operators (1) Document why it is infeasible to utilize a non-emitting method due to technical, safety, or economic reasons; (2) develop BMPs that ensure that emissions during liquids unloading are minimized including, at a minimum, having a person on-site during the liquids unloading event to expeditiously end the venting when the liquids have been removed; (3) follow the BMPs during each liquids unloading event and maintain records demonstrating they were followed; and (4) report the number of liquids unloading events in an annual report, as well as the unloading events when the BMP was not followed. While the proposed rule would not dictate all of the specific practices that must be included, it would specify minimum acceptance criteria required for the types and nature of the practices. Examples of the types and nature of the required practice elements are provided in XII.D.1.e.

For Option 2, the affected facility would be defined as every well that undergoes liquids unloading using a method that is not designed to totally eliminate venting. The significant difference in this option is that wells that utilize non-venting methods would not be affected facilities that are subject to the NSPS OOOOb. Therefore, they would not have requirements other than to maintain records to document that they used non-venting liquids unloading methods. The requirements for wells that use methods that vent would be the same as described above under Option 1. The EPA solicits comment on including information such as where the well stream was directed during unloading and emissions manifested and whether an estimate of the VOC and methane emissions generated should be included in the annual report.

There are several techniques owners and operators can choose from to unload liquids, including manual unloading, velocity tubing or velocity strings, beam or rod pumps, electric submergence pumps, intermittent unloading, gas lift (*e.g.,* use of a plunger lift), foam agents, wellhead compression, and routing the gas to a sales line or back to a process. Although the unloading method employed by an owner or operator can itself be a method that can be employed in such a way that mitigates/eliminates venting of emissions from a liquids unloading event, indicating a particular method to meet a particular well's unloading needs is a production engineering decision. Based on available information, liquids unloading operations are often conducted in such a way that eliminates venting to the atmosphere and there are many options that include techniques and procedures that an owner or operator can choose from to achieve this standard (discussed in section XII.D.e of this preamble).

However, the EPA recognizes that there may be reasons that a non-venting method is infeasible for a particular well, and the proposed rule would allow for the use of BMPs to reduce the emissions to the maximum extent possible for such cases (discussed in section XII.D of this preamble). BMPs include, but are not limited to, following specific steps that create a differential pressure to minimize the need to vent a well to unload liquids and reducing wellbore pressure as much as possible prior to opening to atmosphere via storage tank, unloading through the separator where feasible, and requiring an operator to remain on-site throughout the unloading, and closure of all well head vents to the atmosphere and return of the well to production as soon as practicable. For example, where a plunger lift is used, the plunger lift can be operated so that the plunger returns to the top and the liquids and gas flow to the separator. Under this scenario, venting of the gas can be minimized and the gas that flows through the separator can be routed to sales. In situations where production engineers select an unloading technique that vents emissions or has the potential to vent emissions to the atmosphere, owners and operators already often implement BMPs in order to increase gas sales and reduce emissions and waste during these (often manual) liquids unloading activities.

2. EG OOOOc

The EPA has determined that each well liquids unloading event represents a modification, which will make the well subject to new source standards under the NSPS for purposes of the liquids unloading standards.[203] Therefore, after the effective date of NSPS OOOOb, the first time a well undergoes liquids unloading it will become subject to NSPS OOOOb. This will mean that there will never be a well that undergoes liquids unloading that will be existing. Therefore, we are not proposing presumptive standards under the subpart OOOOc EG.

E. Reciprocating Compressors

1. NSPS OOOOb

The current NSPS in subpart OOOOa for reducing VOC and methane emissions from reciprocating compressors is to replace the rod packing on or before 26,000 hours of operation or 36 calendar months, or to route emissions from the rod packing to a process through a closed vent system under negative pressure. The affected facility is each reciprocating compressor, with the exception of reciprocating compressors located at well sites. Based on the analysis in section XII.E.1, the proposed BSER for reducing GHGs and VOC from new reciprocating compressors is replacement of the rod packing based on an annual monitoring threshold. Under this proposal for the NSPS, we would continue to retain, as an alternative, the option of routing rod packing emissions to a process via a closed vent system under negative pressure. In this proposed updated standard, the owner or operator of a reciprocating compressor affected facility would be required to monitor the rod packing emissions annually using a flow measurement. When the measured leak rate exceeds 2 scfm (in pressurized mode), replacement of the rod packing would be required.

As mentioned above, reciprocating compressors that are located at well sites are not affected facilities under the 2016 NSPS OOOOa. The EPA previously excluded them because we found the cost of control to be unreasonable. 81 FR 35878 (June 3, 2016). Our current analysis, as summarized in section XII.E.1, continues to support this exclusion for a subset of well sites so this proposal for NSPS OOOOb includes that same exclusion for well sites that are not centralized production facilities. See section XI.L for additional details on centralized production facilities. As described in that section, the EPA is proposing to apply the proposed standards to reciprocating compressors located at centralized production facilities.

2. EG OOOOc

Based on the analysis in section XII.E.2, the EPA is proposing EG that include a presumptive GHG standard (in the form of limitation on methane emissions) for existing reciprocating compressors that is the same as the proposed NSPS, including applying these presumptive standards to reciprocating compressors located at existing centralized tank batteries.

F. Centrifugal Compressors

1. NSPS OOOOb

The current NSPS in subpart OOOOa for wet seal centrifugal compressors is 95 percent reduction of GHGs and VOC emissions. The affected facility is each wet seal centrifugal compressor, with the exception of wet seal centrifugal compressors located at well sites. Based on the analysis in section XII.F.1, the BSER for reducing GHGs and VOC from new, reconstructed, or modified wet seal centrifugal compressors is the same as the current standard, which is 95 percent reduction of GHG and VOC emissions. The standard can be achieved by capturing and routing the emissions, using a cover and closed vent system, to a control device that achieves an emission reduction of 95 percent, or by routing captured emissions to a process.

As discussed above, wet seal centrifugal compressors that are located at well sites are not affected facilities under the 2016 NSPS OOOOa. The EPA previously excluded them because data available at the time did not suggest there were a large number of wet seal centrifugal compressors located at well sites. 81 FR 35878 (June 3, 2016). Our analysis continues to support this exemption for wet seal centrifugal compressors located at well sites that are not centralized production facilities. See section XI.L for additional details on centralized production facilities. As described in that section, the EPA is proposing to apply the proposed standards to centrifugal compressors located at centralized production facilities.

2. EG OOOOc

Based on the analysis in section XII.F.2, the EPA is proposing EG that

[203] To clarify further, when a well liquids unloading event represents a modification, this does not make the whole well site a new source. Rather, the modification will make the well subject to NSPS for only the liquids unloading standards.

include a presumptive GHG standard (in the form of limitation on methane emissions) for existing wet seal centrifugal compressors that is the same as the NSPS, including applying these presumptive standards to wet seal centrifugal compressors at existing centralized tank batteries.

G. Pneumatic Pumps

1. NSPS OOOOb

The current NSPS in subpart OOOOa regulates individual natural gas driven diaphragm pneumatic pumps at well sites and at onshore natural gas processing plants. The current NSPS for a natural gas driven diaphragm pneumatic pump at well sites requires 95 percent control of GHGs and VOCs if there is an existing control device or process on site where emissions can be routed. There are two exceptions to the 95 percent control requirement: (1) The existing control or process achieves less than 95 percent reduction; or (2) it is technically infeasible to route to the existing control device or process. In addition, the current NSPS in OOOOa specifies that boilers and process heaters are not considered control devices and that routing emissions from pneumatic pump discharges to boilers and process heaters is not considered routing to a process. For more discussion on the use of boilers and process heaters as control devices for pneumatic pump emissions, see section X.B.2 of this preamble. The current NSPS for a natural gas driven diaphragm pneumatic pump at an onshore natural gas processing plant is a natural gas emission rate of zero, based on natural gas as a surrogate for VOC and GHG, the two regulated pollutants.

For NSPS OOOOb, we are proposing to expand the applicability of the standard currently in NSPS OOOOa in two ways. The first is by including all natural gas driven diaphragm pumps as affected facilities in the transmission and storage segment in addition to the production and natural gas processing segments. The second is that we are expanding the affected facility definition to include natural gas driven piston pumps in addition to diaphragm pumps. The proposed definition of an affected facility would continue to exclude lean glycol circulation pumps that rely on energy exchange with the rich glycol from the contractor.

Based on our analysis, which is summarized in section XII.G.1, we are proposing to retain the current standard for a natural gas driven diaphragm pneumatic pump at well sites because the BSER for reducing VOC and methane emissions from such pumps at a well site continues to be routing to a combustion device or process, but only if the control device or process is already available on site. As before, the current analysis continues to show that it is 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. Moreover, even where a control device or process is available onsite that would achieve at least 95 percent control, the EPA is aware that it may not be technically feasible in some instances to route the pneumatic pump to the control device or process. In this situation, the proposed rule would exempt the owner and operator from this requirement provided that they document the technical infeasibility and submit it in an annual report. Another circumstance is that it may be feasible to route the emissions to a control device, but the control cannot achieve 95 percent control. In this instance, the proposed rule would exempt the owner or operator from the 95 percent requirement, provided that the owner or operator maintain records demonstrating the percentage reduction that the control device is designed to achieve. In this way, the standard would achieve emission reductions with regard to pneumatic pump affected facilities even if the only available control device cannot achieve a 95 percent reduction. For more discussion of the technical infeasibility aspects of the pneumatic pump requirements, see section X.B.2 of this preamble. We are proposing to expand these requirements to all diaphragm pumps at all sites in the production segment, as well as at all transmission and storage sites. In addition, we are proposing that these requirements would also include emissions from piston pneumatic pumps at all sites in the production segment.

We are not proposing any change to the current standard of zero natural gas emission for natural gas driven diaphragm pneumatic pumps located at onshore natural gas processing plants, other than the expansion of the affected facility definition to include piston pumps. Our analysis discussed in section XII.G.1 demonstrates this standard is the BSER.

2. EG OOOOc

The EPA is proposing EG that include presumptive methane standards that are the same as described above for the NSPS OOOOb for existing natural gas driven diaphragm pneumatic pumps located at well sites and all other sites in the production segment (except processing plants) and transmission and storage segment where an existing control device exists. However, unlike the proposed methane standards in NSPS OOOOb for natural gas driven piston pneumatic pumps at sites in the production segment, the proposed presumptive standards under EG OOOOc exclude piston pumps from the 95 percent control requirements. The EPA's proposed emissions guidelines also include a presumptive methane standard for pneumatic pumps located at onshore natural gas processing plants that is the same as the proposed NSPS described above.

H. Equipment Leaks at Natural Gas Processing Plants

Based on our analysis, which is summarized in section XII.H.1, the EPA is proposing to update the NSPS for reducing VOC and methane emissions from equipment leaks at onshore natural gas processing plants. Further, based on the same analysis in section XII.H.1 and the EPA's understanding that it is appropriate to apply that same analysis to existing sources, the EPA is also proposing EG that include these same LDAR requirements as presumptive standards for reducing methane leaks from existing equipment at onshore natural gas processing plants.

The EPA is proposing to expand the definition of an affected facility (referred to as a ''equipment within a process unit'') and establish a new standard for reducing equipment leaks of VOC and methane emissions from new, modified, and reconstructed process units at onshore natural gas processing plants. This proposed standard would require (1) the use of OGI monitoring to detect equipment leaks from pumps, valves, and connectors, and (2) retain the current requirements in the 2016 NSPS OOOOa (which adopts by reference specific provisions of 40 CFR part 60, subpart VVa (''NSPS VVa'')) for PRDs, open-ended valves or lines, and closed vent systems and equipment designated with no detectable emissions.

First, we are proposing to remove a threshold that excludes certain equipment within a process unit from being subject to the equipment leaks standards for onshore natural gas processing plants. While the current definition of an affected facility includes all equipment, except compressors, that is in contact with a process fluid containing methane or VOCs (*i.e.,* each pump, PRD, open-ended valve or line, valve, and flange or other connector), the standards apply only to equipment ''in VOC service,'' which ''means the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight.'' We are proposing to remove this VOC concentration threshold from the LDAR requirements for the following reasons. First, a VOC concentration threshold bears no relationship to the LDAR for methane and is therefore not an appropriate threshold for determining whether LDAR for methane applies. Second, since there would be no threshold for requiring LDAR for methane, any equipment not in VOC service would still be required to conduct LDAR for methane even if not for VOC, thus rendering this VOC concentration threshold irrelevant.

Second, for all pumps, valves, and connectors located within an affected process unit at an onshore natural gas processing plant, we are proposing to require the use of OGI to identify leaks from this equipment on a bimonthly frequency (*i.e.,* once every other month), which according to our analysis is the BSER for identifying and reducing leaks from this equipment. OGI monitoring would be conducted in accordance with the proposed appendix K,[204] which is included in this action and outlines the proposed procedures that must be followed to identify leaks using OGI. As an alternative to bimonthly monitoring using OGI, we are proposing to allow affected facilities the option to comply with the requirements of NSPS VVa, which are the current requirements in the 2016 NSPS OOOOa.[205] As explained in XII.A, our analysis shows that the proposed standards, which use OGI, achieve equivalent reduction of VOC and methane emissions as the current standards, which are based on EPA Method 21, but at a lower cost. While we no longer consider EPA Method 21 to be the BSER for reducing methane and VOC emissions from equipment leaks at onshore natural gas processing plants, we are retaining NSPS VVa as an alternative for owners and operators who prefer using EPA Method 21.

Third, we are proposing to require a first attempt at repair for all leaks identified with OGI within 5 days of detection, and final repair completed within 15 days of detection. We are also proposing definitions for ''first attempt at repair'' and ''repaired.'' The proposed definitions would apply to the equipment leaks standards at natural gas processing plants as well as to fugitive emissions requirements at well sites and compressor stations. The proposed definition of ''first attempt at repair'' is an action taken for the purpose of stopping or reducing fugitive emissions or equipment leaks 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. The proposed definition for ''repaired'' is fugitive emissions components or equipment are adjusted, replaced, or otherwise altered, in order to eliminate fugitive emissions or equipment leaks as defined in the subpart and resurveyed to verify that emissions from the fugitive emissions components or equipment are below the applicable leak definition. Repairs can include replacement with low-emissions (''low-e'') valves or valve packing, where commercially available, as well as drill-and-tap with a low-e injectable. These low-e equipment meet the specifications of API 622 or 624. Generally, a low-e valve or valve packing product will include a manufacturer written warranty that it will not emit fugitive emissions at a concentration greater than 100 ppm within the first five years. Further, we are proposing to incorporate the delay of repair provisions that are in 40 CFR 60.482–9a of NSPS VVa (and incorporated into NSPS OOOOa). These provisions would allow the delay of repairs where it is technically infeasible to complete repairs within 15 days without a process unit shutdown and require repair completion before the end of the next process unit shutdown.

Fourth, we are proposing to retain the current requirements in NSPS OOOOa for open-ended valves or lines, closed vent systems and equipment designated with no detectable emissions, and PRDs. For open-ended valves or lines, we propose to retain the requirements in 40 CFR 60.482–6a of NSPS VVa. Specifically, we are proposing that each open-ended valve or line in a new or existing process unit 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 requiring process fluid flow through the open-ended valve or line. The EPA is soliciting comment on requiring OGI monitoring (or EPA Method 21 monitoring for those opting for that alternative) on these open-ended valves or lines equipped with closure devices to ensure no emissions are going to the atmosphere. Specifically, the EPA is soliciting information that would aid in determining what additional costs would be incurred from either OGI or EPA Method 21 monitoring and repair of leaking open-ended valves or lines, and information on leak rates and concentrations of emissions, where monitoring has been performed.

While the EPA is proposing to retain the no detectable emission requirement in NSPS OOOOa for closed vent systems and equipment designated as having no detectable emissions (*e.g.,* valves or PRDs), the EPA is also soliciting comment on whether bimonthly OGI monitoring according to the proposed appendix K is appropriate to demonstrate compliance with this requirement. The current NSPS requires the closed vent systems[206] and the other equipment described above to operate with no detectable emissions, as demonstrated by an instrument reading of less than 500 ppm above background with EPA Method 21. On December 22, 2008, the EPA issued a final rule titled, ''Alternative Work Practice to Detect Leaks from Equipment'' (*AWP*).[207] In that final rule, the EPA did not permit the use of OGI for this equipment, stating, ''the AWP is not appropriate for monitoring closed vent system, leakless equipment, or equipment designated as non-leaking. While the AWP will identify leaks with larger mass emission rates, tests conducted with both the AWP and the current work practice indicate the AWP, at this time, does not identify very small leaks and may not be able to identify if non-leaking/leakless equipment are truly nonleaking because the detection sensitivity of the optical gas imaging instrument is not sufficient.'' 73 FR 78204 (December 22, 2008). The EPA is soliciting information that would support the use of OGI for closed vent systems and equipment designated with no detectable emissions at new and existing process units, including comment on applying the proposed bimonthly OGI monitoring requirement on this equipment in place

[204] ''Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging'' located at Docket ID No. EPA–HQ–OAR–2021–0317.

[205] It is important to note that the stay of the connector monitoring requirements in 40 CFR 60.482–11a does not apply to connectors located at onshore natural gas processing plants. Therefore, where sources choose to comply with the requirements of NSPS VVa in place of the proposed OGI requirements, the standards in 40 CFR 60.482–11a are applicable to all connectors in the process unit.

[206] For purposes of this standard, the EPA is referring to closed vent systems used equipment within process units at onshore natural gas processing plants. Closed vent systems associated with controlled storage vessels, wet seal centrifugal compressors, reciprocating compressors and pneumatic pumps are not included in this discussion and would demonstrate compliance with the no detectable emissions standard by EPA Method 21 (except for storage vessels), monthly AVO, or OGI monitoring during the fugitive emissions survey.

[207] See 73 FR 78199 (December 22, 2008).

of the NSPS VVa annual EPA Method 21 monitoring.

Finally, the EPA is proposing to retain the emission standards for PRDs found in 40 CFR 60.482–4a of NSPS VVa. This provision requires that PRDs be operated with no detectable emissions, except during pressure releases at new and existing process units. As stated above, the EPA is soliciting comment on the use of OGI to demonstrate that PRDs are meeting this operational emission standard.

2. EG OOOOc

The EPA is proposing EG that include a presumptive methane standard that is the same as described above for the NSPS OOOOb for equipment leaks at existing onshore natural gas processing plants. Based on the analysis in section XII.H.2, the BSER for reducing GHGs from equipment leaks at new and existing onshore natural gas processing plants are the same.

I. Well Completions

Based on our understanding that there are no advances in technologies or practices, which is summarized in section XII.I, the EPA is proposing to retain the REC and completion combustion requirements for reducing methane and VOC emissions from well completions of hydraulically fractured or refractured oil and natural gas wells, as they continue to reflect the BSER. These proposed standards are the same as those for natural gas and oil wells regulated in the 2012 NSPS OOOO and 2016 NSPS OOOOa, as amended in the 2020 Technical Rule for VOC and proposed in section X.B.1 for methane.[208] Because of the nature of well completions, any completion (or recompletion) is considered a new or modified well affected facility, therefore, the EPA does not believe there are existing well affected facilities to which a EG OOOOc presumptive standard for well completions would apply.

J. Oil Wells With Associated Gas

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. There are no current NSPS requirements for this emission source. The EPA is proposing standards in the NSPS OOOOb to reduce methane and VOC emissions resulting from the venting of associated gas from oil wells.

1. NSPS OOOOb

We are proposing standards to reduce methane and VOC emissions from each oil well that produces associated gas. Based on our analysis, which is summarized in section XII.J, we are proposing a standard under NSPS OOOOb that requires owners or operators of oil wells to route associated gas to a sales line. In the event that access to a sales line is not available, we are proposing that 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. As discussed in section XII.J, the EPA is soliciting comment on how ''access to a sales line'' should be defined. An affected facility would be defined as any oil well that produces associated gas. The proposed rule would require that when using a flare, the flare must meet the requirements in 40 CFR 60.18 and that monitoring, recordkeeping, and reporting be conducted to ensure that the flare is constantly achieving the required 95 percent reduction. As discussed in section XII.J, the EPA is soliciting comment on an alternative affected facility definition that would exclude oil wells that route all associated gas to a sales line. The EPA is also soliciting comment and information that would support requirements using other strategies to reduce venting and flaring of associated gas from oil wells. The EPA is specifically requesting comment on whether the proposed requirements will incentivize the sale or productive use of captured gas, and if not, other methods that the EPA could use to incentivize or require the sale or productive use instead of flaring.

2. EG OOOOc

The EPA is proposing presumptive standards for existing oil wells in this action that are the same as discussed above for new sources.

K. Sweetening Units

Based on our understanding that no advances in technologies or practices are available to reduce SO_2 emissions from sweetening units, as described in section XII.K, the EPA is proposing to retain the standards as it continues to reflect the BSER. These proposed standards are the same as those for sweetening units regulated in the 2016 NSPS OOOOa, and as amended in the 2020 Technical Rule.[209]

L. Centralized Production Facilities

The EPA is also proposing a new definition for ''centralized production facility,'' which is one or more permanent storage tanks and all equipment at a single stationary source 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. The EPA is proposing this definition to (1) specify how the fugitive emissions requirement apply to centralized production facilities, (2) specify how exemptions related to 40 CFR part 60, subpart K, Ka, or Kb (''NSPS Kb) may apply, and (3) specify what standards would apply to reciprocating and centrifugal compressors located at these facilities.

First, the EPA is proposing to specify how the fugitive emission requirements apply to centralized production facilities. The 2016 NSPS OOOOa, as originally promulgated, provided that ''[f]or purposes of the fugitive emissions standards at 40 CFR 60.5397a, [a] well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (*e.g.,* centralized tank batteries).'' 40 CFR 60.5430a. The inclusion of centralized tank batteries in the definition of well site was used to clarify the boundary of a well site for purposes of the fugitive emissions requirements. Further, in the RTC[210] for the 2016 NSPS OOOOa we stated, ''[o]ur intent is to limit the oil and gas production segment up to the point of custody transfer to an oil and natural gas mainline pipeline (including transmission pipelines) or a natural gas processing plant. Therefore, the collection of fugitive emissions components within this boundary are a part of the well site.'' The EPA continues to define these facilities as a type of well site but is proposing a separate definition to provide further

[208] See Docket ID No. EPA–HQ–OAR–2021–0317 for proposed redline regulatory text for 40 CFR 60.5375a as a reference for the specific well completion standards proposed for NSPS OOOOb.

[209] See Docket ID No. EPA–HQ–OAR–2021–0317 for proposed redline regulatory text for 40 CFR 60.5375a as a reference for the specific well completion standards proposed for NSPS OOOOb.

[210] See Document ID No. EPA–HQ–OAR–2010–0505–7632 at page 4–194.

clarity, especially as it relates to when these facilities are modified, and thus become subject to the fugitive emissions requirements in NSPS OOOOb. The EPA has determined it is appropriate to rename this site as a centralized production facility and to provide the specific definition above to avoid confusion with the storage vessel affected facility, of which applicability is determined for a tank battery, and to better specify the facility name based on the basic function the site performs (*i.e.,* production operations).

Second, the EPA has received questions related to whether NSPS Kb would apply to the storage vessels at centralized production facilities. There is an exemption in NSPS Kb for storage vessels in the producing operations that are below a specific size. Specifically, 40 CFR 60.110(b)(4) exempts ''vessels with a design capacity less than or equal to 1,589.874 m^3 used for petroleum or condensate stored, processed, or treated prior to custody transfer.'' This exemption is a revision of an exemption originally promulgated in 40 CFR part 60, subpart K (''NSPS K''). NSPS K ''does not apply to storage vessels for the crude petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.'' 40 CFR 60.110(b). In that final rule the EPA explained that, ''[t]he storage of crude oil and condensate at producing fields is specifically exempted from the standard.'' 39 FR 9312 (March 8, 1974). While ''producing fields'' were not explicitly defined, NSPS K defined the terms ''custody transfer'' and ''drilling and production facility''. For purposes of NSPS K, custody transfer means ''the transfer of produced crude petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.'' 40 CFR 60.111(g). Drilling and production facility means ''all drilling and servicing equipment, wells, flow lines, separators, equipment, gathering lines, and auxiliary nontransportation-related equipment used in the production of crude petroleum but does not include natural gasoline plants.'' 40 CFR 60.111(h). The definition of ''custody transfer'' was later also incorporated into 40 CFR part 60, subpart Ka (''NSPS Ka''), NSPS Kb, and 40 CFR part 63, subpart HH (National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities).

Instead of a categorical exemption for storage vessels located at drilling and production facilities, NSPS Ka, and subsequently NSPS Kb, adopted threshold-based exemptions that are based on the capacity of an individual storage vessel used to store petroleum (crude oil) or condensate prior to custody transfer. In NSPS Ka, the EPA stated ''[t]his exemption applies to storage between the time that the petroleum liquid is removed from the ground and the time that custody of the petroleum liquid is transferred from the well or producing operations to the transportation operations'' 45 FR 23377 (April 4, 1980). In NSPS Kb, the EPA further stated that ''[t]he promulgated standards for petroleum liquid storage vessels specifically exempted vessels with a capacity less than 420,000 gallons and storing petroleum (crude oil) and condensate prior to custody transfer (production vessels). The emission controls that are applicable to the storage vessels included in the standards being proposed are not applicable to production vessels.'' 49 FR 29701.

The EPA finds it inappropriate to use the controls required by NSPS K, Ka, and Kb on storage vessels located in the production segment, especially where flash emissions are prevalent. Specifically, the NSPS K, Ka, and Kb control requirements include provisions allowing the use of floating roofs to reduce emissions from storage tanks. Floating roofs are not designed to store liquid (or gases) under pressure. Pressurized liquid sent to a storage vessel from a well or separator or other process that operates above atmospheric pressure may contain dissolved gases. These gases will be released or ''flash'' from the liquid as the fluid comes to equilibrium with atmospheric pressure within the storage vessel. The flash gas will either be released from gaps in the seal system or from ''rim vents'' on the floating roof. The rim vent may be an open tube or may be fitted with a low-pressure relief valve, but it is specifically designed to allow any gas entrained or dissolved in the storage liquid to be released above the floating roof. That is, floating roofs are not designed to prevent the release of flash gas, they are only designed to limit the volatilization of a liquid that occurs when the storage liquid is directly exposed with unsaturated air. Since a significant portion of emissions from storage vessels at well sites or centralized production facilities are from flash gas, floating roofs are much less effective at reducing storage vessel emissions than venting these emissions through a CVS to a control or recovery device.

Further, it is the EPA's understanding that these centralized production facilities carry out the same operations that would be conducted at the individual well sites. Therefore, the EPA is proposing a definition of ''centralized production facility'' that clearly specifies these facilities are located within the producing operations. Therefore, if all other conditions are met (*i.e.,* vessels with a design capacity less than or equal to 1,589.874 m^3 used for petroleum or condensate stored, processed, or treated prior to custody transfer), storage vessels at these centralized facilities would meet the exemption criteria for NSPS Kb.

Alternatively, the EPA is soliciting comment on whether it would be more appropriate to specify within the proposed NSPS OOOOb and EG OOOOc that storage vessels at well sites and centralized production facilities are subject to the requirements in NSPS OOOOb and EG OOOOc instead of NSPS K, Ka, or Kb. This alternative approach would eliminate the need for sources to determine if the storage vessel meets the exemption criteria specified in those subparts and instead focus on appropriate controls for the storage vessels based on the location and type of emissions likely present (*e.g.,* flash emissions).

Finally, the EPA is now proposing to define centralized production facilities separately from well sites because the number and size of equipment, particularly reciprocating and centrifugal compressors, is larger than standalone well sites which would not be included in the proposed definition of ''centralized production facilities'' above. In the 2016 NSPS OOOOa, the EPA exempted reciprocating and centrifugal compressors located at well sites from the applicable compressor standards.

Reciprocating compressors that are located at well sites are not affected facilities under the 2016 NSPS OOOOa. The EPA previously excluded them because we found the cost of control to be unreasonable. 81 FR 35878. However, as mentioned above, the EPA believes the definition of ''well site'' in NSPS OOOOa may cause confusion regarding whether reciprocating compressors located at centralized production facilities are also exempt from the standards. In our current analysis, described in section XII.E, we find it is appropriate to apply the same emission factors to reciprocating compressors located at centralized production facilities as those used for reciprocating compressors at gathering and boosting compressor stations. Given the results of that analysis, the EPA is proposing to apply the proposed NSPS OOOOb and presumptive standards in EG OOOOc to reciprocating compressors located at centralized production facilities. The new definition above is intended to apply the results of the EPA's analysis. We believe that this new definition is necessary in the context of reciprocating compressors to distinguish between these compressors at centralized production facilities where the EPA has determined that the standard should apply, and these compressors at standalone well sites where the EPA has determined that the standard should not apply. See section XII.E for more details of those proposed standards.

Similarly, wet seal centrifugal compressors that are located at well sites are not affected facilities under the 2016 NSPS OOOOa. The EPA previously excluded them because data available at the time did not suggest there were a large number of wet seal centrifugal compressors located at well sites. 81 FR 35878. In our current analysis, described in section XII.F, we find it is appropriate to apply the same emission factors to wet seal centrifugal compressors located at centralized production facilities as those used for these same compressors at gathering and boosting compressor stations. Given the results of that analysis, the EPA is proposing to apply the proposed NSPS OOOOb and presumptive standards in EG OOOOc to wet seal centrifugal compressors located at centralized production facilities. See section XII.F for more details of those proposed standards.

M. Recordkeeping and Reporting

The EPA is proposing 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) at *https://cdx.epa.gov/*.) 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. Performance test results collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the ERT website [211] at the time of the test would be required to be submitted in the format generated through the use of the ERT or an electronic file consistent with the xml schema on the ERT website, and other performance test results would be submitted in portable document format (PDF) using the attachment module of the ERT. For semiannual and annual reports, the owner or operator would be required to use the appropriate spreadsheet template to submit information to CEDRI.

The EPA is also proposing to allow owners and operators the ability to seek extensions for submitting electronic reports 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 the time just prior to a report's due date. The EPA is providing these potential extensions to protect owners and operators from noncompliance in cases where they cannot successfully submit a report by the reporting deadline for reasons outside of their control. The decision to accept the claim of needing additional time to report is within the discretion of the Administrator.

Electronic reporting is required in the amended 2016 NSPS OOOOa, and the EPA believes that the electronic submittal of these reports in the proposed NSPS OOOOb will increase the usefulness of the data contained in those reports, is in keeping with current trends in data availability, will further assist in the protection of public health and the environment, and will ultimately result in less burden on the regulated community. Electronic reporting can also eliminate paper-based, manual processes, thereby saving time and resources, simplifying data entry, eliminating redundancies, minimizing data reporting errors, and providing data quickly and accurately to the affected facilities, air agencies, the EPA, and the public. Moreover, electronic reporting is consistent with the EPA's plan [212] to implement E.O. 13563 and is in keeping with the EPA's agency-wide policy [213] developed in response to the White House's Digital Government Strategy.[214]

In addition to the annual and semiannual reporting requirement, the EPA is soliciting comment on what elements, if any, are appropriate for more frequent reporting, and what mechanism would be appropriate for the collection and public dissemination of this information. For example, it may be appropriate to make information related to large emission events public in a timelier manner than the annual reporting period. Therefore, the EPA is soliciting comment on the appropriate mechanism to use for this type of report, including how the data would be reported, who would manage that reporting system, the frequency at which the data should be reported, the potential benefits of more frequent reporting for reducing emissions, the associated burden with this type of reporting and ways to mitigate that burden, and other considerations that should be taken into account.

N. Prevention of Significant Deterioration and Title V Permitting

The pollutant we are proposing to regulate is GHGs, not methane as a separately regulated pollutant. As explained in section XV of this preamble, we are proposing to add provisions to NSPS OOOOb and EG OOOOc, analogous to what was included in the 2016 NSPS OOOOa and other rules regulating GHGs from electric utility generating units, to make clear in the regulatory text that the pollutant regulated by this rule is GHGs. The proposed addition of these and other provisions is intended to address some of the potential implications on the CAA Prevention of Significant Deterioration (PSD) preconstruction permit program and the CAA title V operating permit program.

XII. Rationale for Proposed NSPS OOOOb and EG OOOOc

The following sections provide the EPA's BSER analyses and the resulting proposed NSPS to reduce methane and VOC emissions and the resulting proposed EG, which include presumptive standards, to reduce methane emissions from across the Crude Oil and Natural Gas source category. Our general process for evaluating BSER for the emission sources discussed below included: (1) Identification of available control measures; (2) evaluation of these measures to determine emission reductions achieved, associated costs, non-air environmental impacts, energy impacts and any limitations to their application; and (3) selection of the control techniques that represent

[211] *https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert.*

[212] EPA's Final Plan for Periodic Retrospective Reviews, August 2011. Available at: *https://www.regulations.gov/document?D=EPA-HQ-OA-2011-0156-0154.*

[213] E-Reporting Policy Statement for EPA Regulations, September 2013. Available at: *https://www.epa.gov/sites/production/files/2016-03/documents/epa-ereporting-policy-statement-2013-09-30.pdf.*

[214] Digital Government: Building a 21st Century Platform to Better Serve the American People, May 2012. Available at: *https://obamawhitehouse.archives.gov/sites/default/files/omb/egov/digital-government/digital-government.html.*

BSER.[215] As discussed in the 2016 NSPS OOOOa, the available control technologies will reduce both methane and VOC emissions at the same time. The revised BSER analysis we have undertaken for the sources addressed in the proposed NSPS OOOOb continues to support this conclusion. CAA Section 111 also requires the consideration of cost in determining BSER. Section IX describes how the EPA evaluates the cost of control for purposes of this rulemaking. Sections XII.A through XII.I provide the BSER analysis and the resulting proposed NSPS and EG for the individual emission sources contemplated in this action. Please note that there are minor differences in some values presented in various documents supporting this action. This is because some calculations have been performed independently (*e.g.,* NSPS OOOOb and EG OOOOc TSD calculations for NSPS OOOOb and EG OOOOc focused on unit-level cost-effectiveness and RIA calculations focused on national impacts) and include slightly different rounding of intermediate values.

For this proposed 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.[216] As discussed in each of the EG-specific subsections below, the EPA's evaluation of BSER in the context of existing sources utilized much of the same information as our BSER analysis for the NSPS. This is because within the oil and natural gas industry many of the control measures that are available to reduce emissions of methane from existing sources are the same as those control measures available to reduce VOC and methane emissions from new, modified, and reconstructed sources. By extension, many of the methane emission reductions achieved by the available control options, as well as the associated costs, non-air environmental impacts, energy impacts, and limitations to their application, are very similar if not the same for new and existing sources. Any relevant differences between new and existing sources in the context of available control measures or any other factors are discussed in the EG-specific subsections below.

Where the EPA identified relevant distinctions between new and existing sources in the context of evaluating BSER, it was typically regarding the cost of control options. While many factors can cause differences in the cost of control between new and existing sources, the EPA would like to highlight two general concepts to illustrate how the oil and natural gas industry is unique. These concepts are the ''size'' of the affected facility and the type of standards. First, affected facilities defined in any given NSPS can range from entire process units to individual pieces of equipment. For affected facilities comprised of an entire process unit, or very large processes or equipment, there can be significant differences between the cost of construction or modification for a new source as compared to the cost of a retrofit required for implementation of a control at an existing source. In the case of a new sources, there can be cost savings associated with the up-front planning for the installation of controls which cannot be achieved at existing sources that must instead retrofit already existing processes or equipment. This is particularly true of controls involving equipment changes or add-on control devices. In contrast, most affected facilities for which the EPA is proposing standards in NSPS OOOOb are more narrowly defined. For example, a pneumatic controller affected facility is generally defined as a single natural gas-driven pneumatic controller, which is a discrete and relatively small piece of equipment in a larger process. Another example is the reciprocating compressor affected facility which is defined as a single reciprocating compressor. As such, the EPA did not identify the same type of cost savings associated with the up-front planning of controls in the oil and gas sector as we might in the context of larger affected facilities. We believe this is one factor that led to costs being very similar for new and existing sources.

Second, with regard to the type of standards, many of the standards proposed for NSPS OOOOb, and the presumptive standards proposed for EG OOOOc, are non-numerical standards, such as work practice standards, that require limited or no significant physical modifications. The EPA found that costs for these non-numerical standards would typically not differ between new and existing sources because the work practice could be implemented in both contexts without the need to first install or retrofit any equipment. Put another way, a work practice tends to operate in the same manner regardless of whether the site is new or existing, and existing sites typically do not need to take any preliminary steps in order to implement the work practice. For these reasons, many of the proposed presumptive standards for EG OOOOc discussed in the following sections mirror the proposed standards identified based on the BSER analyses for NSPS OOOOb.

A. Proposed Standards for Fugitive Emissions From Well Sites and Compressor Stations

1. NSPS OOOOb

There are many potential sources of fugitive emissions throughout the Crude Oil and Natural Gas Production source category. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure and mechanical stresses can also cause components or equipment to emit fugitive emissions. Poor maintenance or operating practices, such as improperly reseated pressure relief valves (PRVs) or worn gaskets and springs on thief hatches on controlled storage vessels are also potential causes of fugitive emissions. Additional sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines, PRDs such as PRVs, pump seals, valves or controlled liquid storage tanks.

In the 2021 GHGI, the methane emissions for 2019 from fugitive emissions in the Crude Oil and Natural Gas source category were 96,000 metric tons methane for petroleum systems and 351,500 metric tons for natural gas systems. These levels represent 6 percent of the total methane emissions estimated from all petroleum systems sources (*i.e.,* exploration through refining) and 5 percent of all methane emissions from natural gas systems (*i.e.,* exploration through distribution). In addition, fugitive emissions may be represented in other categories of the GHGI production segment; for example, a portion of fugitive emissions (as defined in this action) is also expected to be related to fugitive emissions from tank thief hatches, and thief hatches on controlled storage vessels, and those emissions are included in the emissions estimates for storage vessels in the GHGI.

In the 2016 NSPS OOOOa, the EPA promulgated standards to control GHGs (in the form of limitations on methane emissions) and VOC emissions from fugitive emissions components located at well sites and compressor stations. These standards required a fugitive

[215] In the context of developing the draft emissions guidelines contained herein, this general process also follows, and is intended to satisfy, certain requirements of EPA's implementing regulations for CAA section 111(d), namely the specific listed component of a draft EG contained in 40 CFR 60.22a(b)(2), and some elements of paragraph (b)(3).

[216] This is intended to satisfy certain elements of the requirements of EPA's implementing regulations found at 40 CFR 60.22a(b)(3) and (5) with the exception of compliance times which the EPA discusses separately in section XVI.

emissions monitoring and repair program, where well sites and compressor stations had to be monitored semiannually and quarterly, respectively.

a. Fugitive Emissions From Well Sites

Oil and natural gas production practices and equipment vary from well site to well site. A well site can serve one well or multiple wells. Some production sites may include only a single wellhead that is extracting oil or natural gas from the ground, while other sites may include multiple wellheads with a number of operations such as production, extraction, recovery, lifting, stabilization, separation and/or treating of petroleum and/or natural gas (including condensate). In addition, the 2016 NSPS OOOOa definition of well site also includes centralized tank batteries for purposes of the fugitive emissions requirements because, like storage vessels at well sites, centralized tank batteries collect crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells; therefore, ''excluding tank batteries not located at the well site could incentivize some owners or operators to place new tank batteries further away from well sites to make use of such an exemption.'' [217] The equipment to perform these production operations (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) has components that may be sources of fugitive emissions. Therefore, the number of components with the potential for fugitive emissions can vary depending on the number of wells and the number of major production and processing equipment at the site. Another factor that impacts the operations at a well site, and the resulting fugitive emissions potential, is the nature of the oil and natural gas being extracted. This can range from well sites that only extract and handle ''dry'' natural gas to those that extract and handle heavy oil.

In both the 2016 NSPS OOOOa and subsequent amendments in the 2020 Technical Rule, the EPA relied on a model plant approach to estimate emissions from well sites. Model plants were developed to provide a representation of well sites across the spectrum. Separate production-based model plants using component counts to determine baseline emissions were developed. The basic approach used was to assign a number of specific equipment types for each well site model plant and then to estimate the number of components based on assigned numbers of components per equipment type. Primarily, the well site model plants utilized information from the DrillingInfo HPDI® database,[218] the 1996 EPA/GRI Study,[219] EPA's GHG Inventory, and GHGRP subpart W. Fugitive model plants were originally developed for the 2015 NSPS OOOOa proposed rule (80 FR 56614, September 18, 2015) and evolved over time in response to new information and public comments. More information on the history of the model plant development can be found in the 2015 NSPS Proposal TSD,[220] the 2016 NSPS Final TSD,[221] the 2018 NSPS Proposal TSD,[222] and the 2020 NSPS Final TSD.[223]

In this proposal, the EPA is shifting away from using model plants for well sites for the BSER analysis and is instead using an individual site-level emission-calculation approach in order to better characterize and take into account the differences at individual well sites that can lead to a vast range in the magnitude of fugitive emissions, which a model plant cannot do. Provided below is a more detailed explanation of the issues concerning the previous model plant approach, followed by a description of the site-specific baseline emission calculation approach, which is similar to the State of Colorado's LDAR program.

In the 2020 Technical Rule, the EPA created separate model plants to represent fugitive emissions from low production well sites (those producing 15 boe or less per day) and non-low production well sites, as it was generally assumed that low producing sites would have fewer major production and processing equipment and thus lower fugitive emissions. This prior estimate of baseline emissions was calculated using model plant site designs with assumed populations of major production and processing equipment and fixed fugitive emissions component counts. While the estimated baseline emissions from the two model plants differ due to the difference in the assumed populations of major production and processing equipment and fixed fugitive emissions component counts, the estimated baseline emissions were intended to represent the baseline emissions for all well sites represented by each model plant. Since that rulemaking, further analysis of existing and new information indicates that there is significant variation in the well characteristics, type of oil and gas products and production levels, gas composition, operations, and types and quantity of equipment at well sites across the U.S. The TSD for this action further describes existing data and new information received since the 2020 Technical Rule that have been evaluated by the EPA to arrive at the conclusion that there is no one-size-fits-all approach to predicting emissions from well sites and that the emissions vary greatly, in ways that bear little correlation to production levels alone. For example, site-level methane emissions data from comprehensive studies sampled across several different regions at numerous well sites, shows a wide range of methane emissions (*i.e.,* ranging from as low as 0 to as high as 1,200 tpy for marginal or low production wells). Additionally, recently obtained ICR data indicate that actual component counts at well sites with equipment could be higher than those estimated by model plants for low and non-low production, *e.g.,* EPA's non-low model plant could be underestimating number of wells, tanks and separators; and similar observations were made for low production based on this data. Contrary to previous general assumptions, information reviewed also shows that it is not necessarily the case that fugitive emissions from sites with lower production have lower emissions than sites with higher production. In fact, it is quite possible that the inverse can be true (*i.e.,* lower producing sites could have higher emissions and inversely, higher producing sites could have lower emissions.) More information can be found in the NSPS OOOOb and EG TSD for this proposal.

Therefore, the EPA has concluded that the previous model plant approach, which was based on two production levels (equal/above or below 15 boe per day) and the estimated equipment types and numbers associated with each of the two production levels, may not be reflective of the actual baseline fugitive emissions from well sites. Further, the potential for fugitive emissions at any given site is impacted more by the number and type of equipment at the site and maintenance practices, which can vary widely among well sites with low production.[224] Given these

[217] See Document ID No. EPA–HQ–OAR–2010–0505–7632 at page 4–221.

[218] Drilling Information, Inc. 2014. *DI Desktop.* 2014 Production Information Database.

[219] Gas Research Institute (GRI)/U.S. EPA. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks.* June 1996 (EPA–600/R–96–080h).

[220] EPA–HQ–OAR–2010–0505–5021.

[221] EPA–HQ–OAR–2010–0505–7631.

[222] EPA–HQ–OAR–2017–0483–0040.

[223] EPA–HQ–OAR–2017–0483–2290.

[224] See *https://pubs.acs.org/doi/10.1021/acs.est.0c02927, https://data.permianmap.org/*

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limitations in utilizing model plants to analyze fugitive emission reduction programs at well sites with widely varying configurations, operations, and production levels, we find it appropriate to shift away from using model plants and instead rely on the potential fugitive emissions at the individual site in our BSER analysis and resulting proposed standards. Therefore, this new analysis, which is described below, is conducted on this basis.

This site-specific baseline emissions calculation approach is similar to the State of Colorado's LDAR program. The concept is that each site calculates its baseline methane emissions for all the equipment at the site, the number and type of equipment at the well site, the number of fugitive emissions components associated with each piece of equipment, and the site-specific gas composition. The fugitive monitoring frequency would be based on the baseline site-specific methane emissions level calculated based on this information. This calculation is described in detail in section XI.A.2. We believe that this approach will more accurately depict the emissions profile at each individual well site. As a result, the EPA is conducting the BSER analysis based on site-level baseline methane emissions, where the analysis is performed in increments of 1 tpy of site-level baseline methane emissions as discussed more below.

During the rulemaking for the 2016 NSPS OOOOa, the EPA analyzed two options for reducing fugitive methane and VOC emissions at well sites: A fugitive emissions monitoring program based on individual component monitoring using EPA Method 21 for detection combined with repairs and a fugitive emissions monitoring program based on the use of OGI detection combined with repairs. Finding that both methods achieve comparable emission reduction but OGI was more cost effective, the EPA ultimately identified semiannual monitoring of well sites using OGI as the BSER. 81 FR 35856 (June 3, 2016). While there are several new fugitive emissions technologies under development, the EPA needs additional information to fully characterize the cost, availability, and capabilities of these technologies, and they are therefore not being evaluated as potential BSER at this time. However, we are proposing the use of these technologies as an alternative screening method as described in section XI.A.5. For this analysis for both the NSPS and the EG, we re-evaluated the use of OGI as BSER. In the discussion below, we evaluate OGI control options based on varying the frequency of conducting the survey and fugitive emissions repair threshold (*i.e.,* the visible identification of methane or VOC when an OGI instrument is used). For this analysis, we considered biennial, annual, semiannual, quarterly, and monthly survey frequency for well sites.

The regulatory concept for the proposed NSPS OOOOb is that the required frequency of fugitive monitoring would be based on total site baseline methane emissions. At well sites, the composition of gas is predominantly methane (approximately 70 percent on average). Therefore, as shown in our analysis, compared to VOC, methane better reflects the baseline emission level where it is cost effective to regulate both methane and VOC fugitive emissions at well sites. For this reason, we chose to use methane as the threshold for our determination.

For the BSER analyses, we selected for evaluation total site-wide methane emissions increments of 1 tpy of site-level baseline methane emissions ranging from 1 tpy to 50 tpy. The EPA acknowledges that the site-level baseline methane emissions calculated may not account for the presence of large emission events when they occur. However, the EPA has found it inappropriate to apply a factor that assumes every site is experiencing a large emission event annually based on information suggesting that only a small percentage of sites experience these events at any given time.[225]

In 2015, we evaluated the potential emission reductions from the implementation of an OGI monitoring program where we assigned an emission reduction of 40, 60, and 80 percent to annual, semiannual, and quarterly monitoring survey frequencies, respectively. The EPA re-evaluated the control efficiencies under different monitoring frequencies for the 2020 Technical Rule based on comments received on the 2018 proposal and concluded that the assigned control efficiencies described above can be expected from the corresponding monitoring frequencies using OGI.[226] No other information reviewed since that time indicates that the assigned reduction frequencies are different than previously established and the reduction efficiencies are consistent with what current information indicates. In addition, we also evaluated biennial survey frequency for well sites assuming an achievable reduction frequency of 30 percent, and monthly monitoring where information evaluated indicated monthly OGI monitoring has the potential of reducing emissions up towards 90 percent.

It is worth noting that these calculations are based on the expected reductions from ''typical'' component equipment leaks that occur with well-maintained sites. The EPA is aware of situations where equipment malfunctions related to equipment components can cause large emission events that are described in detail in section XII.A.5. In these cases, we expect the emission reductions associated with the different monitoring frequencies evaluated would be significantly higher than assumed above and is the reason we solicit comment on the proposed alternative screening program using advanced measurement technologies to identify and quantify large emission sources. Given the intermittent and stochastic nature of large emission events, it is difficult to apply emission factors that predict the probability of a site experiencing these events within any timeframe. As stated above, the EPA finds it inappropriate to apply a factor that assumes every site is experiencing a large emission event annually given the available data. However, we recognize that identifying and stopping these large emission events is a central purpose of the monitoring requirements proposed in this document, and that quantifying the pollution reduction benefits associated with addressing these large emission events is important to fully capture the benefits and cost-effectiveness of our proposed fugitive emissions monitoring requirements. We also acknowledge there is substantial ongoing research on large emission events that may further inform the EPA's calculations, including the potential to develop factors that take into account a distribution of emissions across well sites and the associated emissions reductions achieved when large emission events are included in the calculation.

We evaluated the costs of a monitoring and repair program under various monitoring frequencies. For

pages/flaring, and *https://www.edf.org/sites/default/files/documents/PermianMapMethodology_1.pdf.*

[225] Brandt, A.R., Heath, G.A., Cooley, D. (2016). *Methane Leaks from Natural Gas Systems Follow Extreme Distributions.* Environ. Sci. Technol. 50, 12512, *https://pubs.acs.org/doi/abs/10.1021/acs.est.6b04303;* Zavala-Araiza, D., Alvarez, R., Lyon, D, et al. (2016). *Super-emitters in natural gas infrastructure are caused by abnormal process conditions.* Nat Commun 8, 14012 (2017). *https://www.nature.com/articles/ncomms14012;* Zavala-Araiza, D., Lyon, D., Alvarez, R. et al. (2015). PNAS 112, 15597. *https://www.pnas.org/content/112/51/15597.*

[226] See 85 FR 57412 and section 2.4.1.1 of the 2020 TSD.

well sites, the capital costs associated with the fugitives monitoring program were estimated to be $1,030 per well site. These capital costs include the cost of developing the fugitive emissions monitoring plan and purchasing or developing a recordkeeping data management system specific to fugitive emissions monitoring and repair. Consistent with the analyses used for the 2016 NSPS OOOOa and 2020 Technical Rule, the EPA assumes that each company will develop a monitoring plan and recordkeeping system that covers a company-defined area, which is assumed to include 22 well sites. This assumption is used because there are several elements of the fugitive monitoring program that are not site-specific. The total company-defined area (22 well site) capital costs are divided evenly to arrive at the $1,030 capital cost per well site estimate.

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 were updated extensively as part of the 2020 Technical Rule, and the EPA has made further updates for this proposal based on more recent information. With these updates, the estimated annual costs of the fugitive emissions program at well sites are estimated to range from $2,490 for biennial monitoring to $8,140 for monthly monitoring.[227] These total annual costs include annualization of the up-front cost at 7 percent interest rate over 8 years. We note these costs are representative of the average annual costs expected at well sites, where larger sites may have larger costs associated with longer surveys or potentially more repairs, while smaller sites may experience the opposite with shorter surveys or potentially less repairs. Therefore, we believe the costs developed for well sites are representative of OGI fugitives monitoring program costs and reflect the best information available at this time.

The EPA requests comment on its range of cost estimates for an OGI fugitives monitoring program. The EPA believes that there will be sufficient supply of OGI equipment and available OGI camera operators for industry to conduct all required monitoring, upon the effective date of the NSPS OOOOb and the subsequent implementation of the EG OOOOc. However, the EPA requests additional information on this capacity and whether there is a likelihood of shortages in the early years of the program that might raise costs. The EPA is also requesting comment on the proposed appendix K and whether the proposed training, certification, and audit provisions are appropriate and do not place undue burden on the ability of industry to satisfy the regulatory requirements.

At well sites, there are savings associated with the gas not being released. The value of the natural gas saved is assumed to be $3.13 per Mcf of recovered gas. Annual costs were also calculated considering these savings.

As discussed in section XI.C, natural gas-driven intermittent pneumatic controllers are designed to vent during actuation only, but these devices are known to malfunction and operate incorrectly, which causes them to release natural gas to the atmosphere when idle. The EPA is proposing a zero VOC and methane emissions standard for natural gas-driven intermittent pneumatic controllers. However, for sites in Alaska located in the production segment (well sites, gathering and boosting stations, and centralized tank batteries) and in the transmission and storage segment that do not have electricity, the EPA is proposing a standard wherein intermittent natural gas-driven pneumatic controllers only vent during actuation and not when idle. See section XII.C on pneumatic controllers for a full explanation of this standard. While these intermittent controllers are their own separate affected facility, we are proposing that they be monitored in conjunction with the fugitive emissions components located at the same well site to verify proper actuation and that venting does not occur during idle times.

We created a matrix that includes, for each site-wide methane emission level, the capital (up front) cost, annual costs (with and without the consideration of savings), emission reductions for methane and VOC, and cost effectiveness (dollar per tons of emission reduction). Cost effectiveness was calculated using two approaches; the single pollutant approach where all the costs are assigned to the reduction of one pollutant; and the multipollutant approach, where half the costs are assigned to the methane reduction and half to the VOC reduction, see discussion in preamble section IX. This was repeated for each site-wide methane emissions level for each monitoring frequency. There were several trends shown in this matrix. As noted above, the annual cost for each individual monitoring frequency is applied to all site-wide emission levels when evaluating that frequency. Therefore, as the emissions (and potential emission reductions) increased, the fugitive emissions monitoring became more cost-effective. For example, for semiannual monitoring, the cost effectiveness ranged from $5,300 per ton of methane reduced (for a 1 tpy site-wide methane site) to $100 per ton (for a 50 tpy site-wide methane site). Also, because the emission reduction increase was greater than the cost increase with increasing monitoring frequency, the fugitive emissions monitoring became more cost-effective with increasing monitoring frequency. For example, for a 10 tpy site-wide methane site, the methane cost effectiveness for annual monitoring was $750 per ton, $530 per ton for semiannual monitoring, and $525 per ton for quarterly monitoring. This trend did not extend to monthly monitoring, as the cost of monthly monitoring increases significantly (almost double) compared to quarterly monitoring, while the emission reduction only increased by 10 percent. The complete matrix is available in the NSPS OOOOb and EG TSD for this rulemaking.

The matrix shows that, on a multipollutant basis, both semiannual and quarterly monitoring at well sites with baseline emissions as low as 2 tpy is cost-effective, and that at 3 tpy, both semiannual and quarterly monitoring are cost-effective based on the methane emissions alone. Cost-effectiveness, however, is not the only relevant factor in setting the BSER, particularly for a source as numerous and diverse as well sites. We estimate that there will be approximately 21,000 new wells each year (and 410,000 existing wells) to which the proposed fugitive emissions requirements will apply.[228] Various studies demonstrate that the vast majority of emissions come from a relatively small subset of wells.[229] [230]

[227] As a comparison, the annualized costs for fugitive emissions monitoring and repair at well sites were estimated to range from $1,900 to $3,500 for annual to quarterly monitoring, respectively, in the 2020 Technical Rule. See 2020 TSD, attachment 5 at Document ID No. EPA–HQ–OAR–2017–0483–2290.

[228] Estimated well counts are based on non-wellhead only sites. Based on information provided by API, we assume that 27% of sites are wellhead only; see Memoranda for Meetings with the American Petroleum Institute (API), September 23, 2021, located at Docket ID No. EPA–HQ– OAR–2021–0317. Absent additional information, we also assume that 27% of wells are wellhead only. The estimated new well count reflects the arithmetic average of well counts over the analysis horizon in the RIA, 2023–2035. The estimated existing well count reflects the total in 2026, which is the first year that we estimate impacts for the emissions guidelines.

[229] Brandt, A., Heath, G., Cooley, D. (2016) *Methane leaks from natural gas systems follow*

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The EPA would like to ensure that resources and effort are focused on those wells that emit the most methane and VOC. Moreover, given the diversity of ownership, while our cost assumption that distributes the costs of recordkeeping evenly across 22 sites within a company-defined area is a reasonable estimate for the population as a whole, it may underestimate the costs and therefore overestimate the cost-effectiveness for owners with fewer than 22 well sites (and conversely, underestimate cost-effectiveness for owners with more than 22 well sites). In order to best focus resources and effort on the well sites with the greatest emissions and more accurately capture costs, particularly for owners with fewer well sites, the EPA requests comment on the number of wells that likely emit at each baseline emissions level, and the baseline emissions level of wells generally owned by owners with few wells. The EPA anticipates that it may refine its BSER determination for well sites through its supplemental proposal based on the information gathered from commenters.

Taking these factors into account, and as explained in more detail below, the EPA proposes to conclude that (1) BSER for well sites with a baseline site-wide emissions level of less than 3 tpy is no regular monitoring, but that to help ensure that these sites actually emit at less than 3 tpy, a one-time survey (following each calculation of site-level baseline methane emissions) would be required to ensure that any abnormalities are addressed; (2) BSER for well sites with a baseline site-wide emissions level of 3 tpy or greater is quarterly monitoring. Because of the uncertainties discussed above, and as explained in more detail below, the EPA further co-proposes to conclude that BSER for well sites with a baseline site-wide emissions level of 3 tpy or greater and less than 8 tpy is semiannual monitoring. Our co-proposal is the same as our main proposal with regard to well sites whose baseline site-wide emissions are less than 3 tpy (no regular monitoring, but a one-time survey) and whose emissions are 8 tpy or greater (quarterly monitoring). The EPA estimates that a majority of fugitive emissions (approximately 86%) can be attributed to wells with site-wide baseline emissions of 3 tpy or greater, where 54% can be attributed to wells with site-wide baseline emissions of 8 tpy or greater.[231]

Proposed BSER for Well Sites with Baseline Emissions Less Than 3 tpy. As noted, in both our main proposal and our co-proposal, we propose to conclude that BSER for well sites with baseline emissions of less than 3 tpy is no regular monitoring, but a one-time survey to help ensure that these sites actually emit at less than 3 tpy.

Based on the matrix described above, the EPA determined that where total site baseline methane emissions are 2 tpy, semiannual and quarterly monitoring costs approximately $2,700/ton methane reduced, while biennial and annual monitoring costs approximately $4,000/ton methane reduced. The costs for VOC reductions range from $10,000 to $15,000/ton VOC reduced for quarterly to biennial monitoring, respectively. These costs are outside the range of what we are proposing to consider cost effective on a single-pollutant basis for both methane and VOC. See Section IX.B. However, when considered on a multipollutant basis, the costs of semiannual and quarterly monitoring are approximately $1,350 per ton methane reduced, and approximately $5,000 per ton of VOC, which we do consider cost-effective. Thus, for sites with total baseline methane emissions of 2 tpy, we conclude that regular monitoring at semiannual or quarterly frequencies would be cost-effective.[232]

We do not propose to conclude that routine monitoring with OGI is the BSER for sites with baseline emissions of less than 3 tpy, however, for several reasons. While the estimates for semiannual and quarterly monitoring are within what we consider to be cost effective for well sites with baseline emissions of 2 tpy, in light of the large cohort of relatively lower-emitting sites, we are concerned that our cost effectiveness estimates may not accurately capture the costs, and therefore cost-effectiveness, of routine monitoring with OGI for businesses that own relatively few well sites. Throughout the development of the 2016 NSPS OOOOa, and in subsequent analyses and rulemaking actions, industry stakeholders have consistently stated that the fugitive monitoring requirements are particularly burdensome for smaller entities that own fewer well sites. The EPA believes that many of these smaller entities are likely to own well sites with baseline emissions of less than 3 tpy, a category that tends to include smaller and less complex facilities with few or no major pieces of production and processing equipment.[233] And as noted, the EPA would like to ensure that resources and effort are focused on well sites with significant emissions. Given the possibility that our cost-effectiveness analysis has overestimated the average number of sites, and therefore underestimated the cost-effectiveness, for this cohort of well sites, the EPA is proposing no regular monitoring at sites with baseline site-wide emissions of less than 3 tpy.

While the EPA is proposing to conclude that BSER for well sites with total site-level baseline methane emissions less than 3 tpy is no regular monitoring, we believe it is essential to ensure that well sites in this monitoring tier are operating in a well-controlled manner, and are not experiencing leaks or malfunctions that would cause their emissions to exceed 3 tpy. Therefore, the EPA is proposing a requirement for owners and operators to conduct a survey, and perform repairs as needed, to demonstrate that the well site is free of leaks or malfunctions and is therefore operating in a manner consistent with the baseline methane emissions calculation.[234] This survey could employ any method available that would demonstrate the actual emissions are consistent with the baseline calculation, including, but not limited to, the use of OGI, EPA Method 21 (which includes provisions for a soap bubble test), or alternative methane detection technologies like those discussed in the proposed screening alternative in section XI.A.5.

The EPA seeks comment on all aspects of this proposed BSER determination, including information, data, and analysis that would shed further light on the factors and concerns just expressed and that would support the establishment of ongoing monitoring requirements at the cohort of sites with baseline methane emissions below 3 tpy. Among other things, the EPA seeks

extreme distributions. Environ. Sci. Technol., DOI: 10.1021/acs.est.6b04303.

[230] Zavala-Araiza, D., Alvarez, R., Lyon, D, et al. (2016). *Super-emitters in natural gas infrastructure are caused by abnormal process conditions.* Nat Commun 8, 14012 (2017). *https://www.nature.com/articles/ncomms14012.*

[231] Percentages were estimated for the baseline scenario in the RIA for the 2030 analysis year by combining the bin percentages presented in RIA Table 2–4 with the projected well site activity data documented in the RIA.

[232] The NSPS OOOOb and EG OOOOc TSD also provide costs for monitoring at 1 tpy, which is not considered cost-effective at any frequency evaluated.

[233] Anna M. Robertson, Rachel Edie, Robert A. Field, David Lyon, Renee McVay, Mark Omara, Daniel Zavala-Araiza, and Shane M. Murphy. ''New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates.''

Environmental Science & Technology 2020 *54* (21), 13926–13934. DOI: 10.1021/acs.est.0c02927.

[234] We anticipate that during the survey to confirm their baseline methane emissions and thus exemption status, sources would also repair the leaks found, consistent with our understanding of the standard industry practice.

comment on the ownership profile of well sites with site-wide baseline emissions less than 3 tpy, the extent to which well sites in this cohort are owned by firms that own relatively few wells, and the relative economic costs associated with requiring regular OGI monitoring at these wells. The EPA also seeks information that would improve our understanding of the overall number of wells that would fall in this cohort of sites, and the contribution these wells make to overall fugitive emissions. And the EPA seeks comment on our estimates of the costs and emission reduction associated with OGI monitoring at this cohort of sites, or other data and analysis that would provide support for regular OGI monitoring at these sites. In addition, the EPA notes that the advanced measurement technologies that form the basis of our proposed alternative screening option in section XI.A.5 could be particularly well-suited for rapidly and cost-effectively detecting recurrences of large emitting events at sites with baseline emissions below 3 tpy. Accordingly, the EPA seeks comment that could inform whether to require the use of these technologies for ongoing monitoring at this cohort of sites, including information on the capabilities of these emerging technologies, methodologies for their use, and the costs and emission reductions associated with using these advanced measurement technologies as part of a mandatory monitoring regime. If appropriate, and based on input received during the comment period, the EPA may consider further addressing monitoring requirements for sites with baseline emissions below 3 tpy as part of a supplemental proposal.

Additionally, the EPA is soliciting comment on different criteria, such as the number of well sites owned by a specific owner, that could better account for factors that may affect the costs of fugitive emissions monitoring. As noted, while the EPA has presented costs on an individual site-level, we have also distributed the costs of recordkeeping evenly across an assumed 22 sites within a company-defined area. While this may be appropriate for companies with larger ownership, it is likely underestimating the cost (and overestimating the cost-effectiveness) on owners with fewer sites. Information provided on small businesses, including ownership thresholds, could be used to further determine differences in OGI monitoring requirements at well sites through a supplemental proposal.

Further, the EPA is soliciting comment on whether the presence of specific major production and processing equipment types at a well site warrants a separate monitoring frequency consideration even where the calculated total site-level baseline methane emissions are below 3 tpy. As mentioned throughout this preamble, the EPA is concerned about the presence of large emission events, which various studies have shown are most often attributed to specific equipment. This equipment includes separators paired with onsite storage vessels, combustion devices, and intermittent pneumatic controllers.[235 236 237] Therefore, the EPA is soliciting comment on whether well sites with these specific types of equipment present must conduct at least semiannual monitoring, regardless of the total site-level baseline methane emissions calculated, including those sites calculated below 3 tpy.

Finally, the EPA believes there is a subset of well sites (*i.e.,* wellhead only well sites) that will never have baseline methane fugitive emissions of 3 tpy or greater. Therefore, the proposed rule would not define these sites as affected facilities, thus removing the need for these sites to determine baseline emissions. As defined in the 2020 Technical Rule, a ''wellhead only well site'' is ''a well site that contains one or more wellheads and no major production and processing equipment.'' The term ''major production and processing equipment'' is defined as including reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water. As described earlier in this section, sites will calculate their baseline methane emissions using a combination of population-based emission factors and storage vessel emissions. The population-based emission factors include emissions from wellheads, reciprocating and centrifugal compressors, glycol dehydrators, heater/treaters, separators, natural gas-driven pneumatic pumps, and natural gas-driven pneumatic controllers (both continuous and intermittent). By definition, a wellhead only well site would not have emissions associated with the major production and processing equipment, which includes storage vessels. Further, this proposed rule would not allow the use of natural gas-driven pneumatic controllers at any location (except on the Alaska North Slope), including wellhead only well sites. Therefore, the only emissions would be calculated based on the fugitive emissions components associated with the wellhead, which we believe would never be above 3 tpy.

Proposed BSER for Sites with Baseline Emissions of 3 tpy or Greater. The EPA next evaluated what frequency of OGI monitoring is BSER for well sites where the total site-level baseline methane emissions are 3 tpy or greater. Table 14 summarizes the cost-effectiveness information for each monitoring frequency evaluated at this threshold.

TABLE 14—SUMMARY OF EMISSION REDUCTIONS AND COST–EFFECTIVENESS FOR SITE–LEVEL BASELINE METHANE EMISSIONS OF 3 TPY

Monitoring frequency	Annual cost ($/yr/site)	Methane emission reduction (tpy/site)	VOC emission reduction (tpy/site)	Single-pollutant		Multipollutant	
				Methane cost-effectiveness ($/ton)	VOC cost-effectiveness ($/ton)	Methane cost-effectiveness ($/ton)	VOC cost-effectiveness ($/ton)
3 tpy site-level baseline methaneemissions							
Biennial	$2,500	0.90	0.25	$2,800	$10,000	$1,400	$5,000
Annual	3,000	1.20	0.33	2,500	9,000	1,250	4,500
Semiannual	3,200	1.80	0.50	1,800	6,400	900	3,200
Quarterly	4,200	2.40	0.67	1,800	6,300	900	3,200
Monthly	8,100	2.70	0.75	3,000	11,000	1,500	5,400

[235] *Id.*

[236] Tyner, David R., Johnson, Matthew R., ''Where the Methane Is—Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data.'' *Environmental Science & Technology* 2021 *55* (14), 9773–9783. DOI: 10.1021/acs.est.1c01572.

[237] 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*.

Based on the information summarized in Table 14, the average costs per ton reduced appear to be reasonable for either semiannual or quarterly monitoring when site-level baseline methane emissions are 3 tpy or greater under the single pollutant approach for methane (biennial, annual, or monthly are outside of what the EPA considers reasonable for VOCs in the single pollutant approach), or reasonable at any frequency under the multipollutant approach.

In addition to considering the average costs per ton reduced for these sites, the EPA also evaluated the incremental cost associated with progressing to greater monitoring frequencies. To conduct this analysis, the EPA first considered semiannual monitoring for these sites as a baseline for comparison. Since 2016, owners and operators have been conducting semiannual monitoring pursuant to NSPS OOOOa, State requirements, or voluntarily, thus demonstrating the reasonableness of that frequency. Additionally, the cost is comparable to the costs found reasonable in the 2016 NSPS OOOOa [238] for both the single pollutant approach for methane or multipollutant approach for both methane and VOC. To determine if quarterly monitoring is reasonable for sites with total baseline methane emissions of 3 tpy, we evaluated the incremental costs of going from semiannual to quarterly monitoring. The incremental costs of semiannual to quarterly monitoring for an emissions baseline of 3 tpy methane is $1,700/ton methane and $6,000/ton VOC using the single pollutant approach (and $800/ton methane and $3,000/ton VOC using the multipollutant cost effectiveness approach). These incremental costs are within the range we find reasonable in this proposal under the single pollutant approach for methane and under the multipollutant approach.

We next evaluated monthly monitoring for this cohort. As shown in Table 14, monthly monitoring appears reasonable under the multipollutant approach. Therefore, we evaluated the incremental costs of going from quarterly monitoring to monthly monitoring to determine if monthly monitoring is appropriate. Table 15 summarizes these incremental costs. As shown in Table 15, the incremental cost of going from quarterly to monthly monitoring when baseline emissions are 3 tpy is $13,000/ton methane and $47,000/ton VOC under the single pollutant approach ($6,500/ton methane and $23,500/ton VOC under the multipollutant approach). In both approaches, these costs are outside the range of what we are proposing to consider cost effective. See Section IX.B.

Based on the analysis described above, we propose to find that quarterly monitoring at well sites with total site-level baseline methane emissions of 3 tpy or greater is the BSER. We note that California requires quarterly inspections for all well sites under its LDAR requirements in Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Article Subarticle 13: *Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities,* which supports a conclusion that quarterly monitoring at these sites is feasible and cost-effective.[239]

Accordingly, the EPA's primary proposal is to conclude that BSER for well sites with total site-level baseline emissions of less than 3 tpy is no regular monitoring (but a one-time survey) and that BSER for well sites with total site-level baseline emissions of 3 tpy or greater is quarterly monitoring and repair.

While the EPA is proposing quarterly OGI monitoring for well sites with total site-level baseline methane emissions of 3 tpy or greater, we are concerned this cost-effectiveness analysis may not fully account for the numerosity and diversity of sites and their potential emission profiles. We further note that some States with established fugitive emissions monitoring programs have provided for more graduated frequencies that recognize this diversity among sites. For example, Colorado's Regulation 7 Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions [240] requires a tiered inspection frequency regime that provides for semiannual monitoring at site-wide baseline emissions thresholds that far exceed the EPA's proposed 3 tpy threshold. Under the Colorado regulations, a semiannual inspection frequency is required for well production facilities with uncontrolled actual VOC emissions between 2 and 12 tpy (corresponding to approximately 7 to 43 tpy methane). Quarterly inspections are required for well sites without storage tanks and with uncontrolled actual VOC emissions between 12 and 20 tpy (corresponding to approximately 43 to 72 tpy methane), and for well sites with storage tanks and with uncontrolled actual VOC emissions between 12 and 50 tpy (corresponding to approximately 43 to 180 tpy methane). Colorado Regulation 7 also requires monthly inspections for well production facilities without storage tanks with uncontrolled actual VOC emissions above 20 tpy (and above 50 tpy for facilities with storage tanks). The proposed thresholds for quarterly monitoring in this action are more stringent than the Colorado regulations when compared using the gas composition ratio of 0.28 VOC to methane that is used in our BSER analysis. Specifically, the VOC emissions associated with a site-level baseline methane emission rate of 3 tpy are 0.83 tpy VOC, less than half the VOC threshold that requires semiannual monitoring and 14.5 times lower than the VOC threshold requiring quarterly monitoring in Colorado.

Although Colorado's regulations are most directly comparable to the EPA's proposed approach, other States also provide for more graduated monitoring frequencies. For example, Ohio's General Permits 12.1 and 12.2 initially require quarterly monitoring for well sites, followed by a reduced monitoring frequency of semiannual or annual monitoring depending on the fraction of equipment found to be leaking.[241]

When considering these State programs, particularly the comparison of our proposal to Colorado's thresholds; the fact that our cost-effectiveness calculation may not account for the diversity of emissions and sites; and the concerns we have raised regarding the cost-effectiveness for businesses with fewer well sites than are assumed in our cost-effectiveness analysis (many of whom we anticipate are small businesses), the EPA believes it is also appropriate to co-propose semiannual monitoring for well sites in a middle cohort—those with total site-level baseline emissions of 3 tpy or greater and less than 8 tpy. We seek comment on the number and ownership profile of wells that would fall into this category to better understand whether semiannual monitoring is an appropriate monitoring frequency for sites in this range.

To inform this analysis, we evaluated methane emissions in 1 tpy increments starting at 3 tpy. Tables 15a and 15b summarize the total costs and incremental costs of semiannual to quarterly for baseline methane

[238] The 2020 Technical Rule amended only the VOC standards in the 2016 NSPS OOOOa and, as discussed in section X.A, incorrectly identified $738/ton as the highest value that the EPA found cost effective for methane reduction in the 2016 NSPS OOOOa.

[239] *https://ww2.arb.ca.gov/sites/default/files/classic/regact/2016/oilandgas2016/ogfro.pdf.*

[240] *https://cdphe.colorado.gov/aqcc-regulations.*

[241] *https://epa.ohio.gov/dapc/genpermit/oil-and-gas-well-site-production.*

emissions of 3 tpy or greater and less than 8 tpy.

TABLE 15A—SUMMARY OF TOTAL COST–EFFECTIVENESS FOR FUGITIVE MONITORING AT WELL SITES

Site-level baseline methane emissions (tpy)	Annual cost ($/yr/site)	Single pollutant cost-effectiveness		Multipollutant cost-effectiveness	
		Methane ($/ton)	VOC ($/ton)	Methane ($/ton)	VOC ($/ton)
Semiannual Monitoring					
3	$3,200	$1,800	$6,400	$890	$3,200
4	3,200	1,300	4,800	670	2,400
5	3,200	1,100	3,800	530	1,900
6	3,200	890	3,200	440	1,600
7	3,200	760	2,700	380	1,400
8	3,200	670	2,400	330	1,200
Quarterly Monitoring					
3	4,200	1,800	6,300	880	3,200
4	4,200	1,300	4,700	660	2,400
5	4,200	1,000	3,800	530	1,900
6	4,200	880	3,200	440	1,600
7	4,200	750	2,700	380	1,400
8	4,200	660	2,400	330	1,200

TABLE 15B—SUMMARY OF INCREMENTAL COST–EFFECTIVENESS FOR FUGITIVE MONITORING AT WELL SITES

Site-level baseline methane emissions (tpy)	Incremental annual cost ($/yr/site)	Incremental methane emission reduction (tpy/site)	Incremental VOC emission reduction (tpy/site)	Incremental cost-effectiveness	
				Methane ($/ton)	VOC ($/ton)
Incremental for semiannual to quarterly					
3	$1,000	0.60	0.17	$1,700	$6,000
4	1,000	0.80	0.22	1,250	4,500
5	1,000	1.00	0.27	1,000	3,600
6	1,000	1.20	0.33	840	3,000
7	1,000	1.40	0.39	720	2,600
8	1,000	1.60	0.45	630	2,250

While there is no obvious cutoff point, the EPA anticipates that well sites with calculated baseline emissions of 8 tpy or greater will generally consist of complex sites comprising multiple wellheads and/or one or more of the major pieces of production or processing equipment that are known to have a propensity for causing large emissions events. The EPA also believes it is possible that at 8 tpy and greater, well sites are both more likely to be owned by companies with a larger number of sites and that the owners of these wells are likely to be larger companies. Lastly, the EPA estimates that a large share of fugitive emissions (approximately 54%) can be attributed to wells with site-wide baseline emissions of 8 tpy or greater.[242] For these reasons, the EPA believes that an 8 tpy threshold for quarterly monitoring would appropriately focus resources on the wells with the largest emissions profiles, and that concerns about on the costs for small owners or operators are most attenuated for this cohort of relatively large and high-emitting sites. As noted above, we seek comment on whether it is sensible to have a middle cohort with a semiannual monitoring requirement and, if so, what the bounds of that cohort should be. In making this determination, the EPA is particularly interested in comments regarding the number and ownership profiles of well sites that may fall into this middle cohort.

As required by section 111, the EPA's proposed BSER analysis for fugitive emissions from all well sites has considered nonair quality health and environmental impacts. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of fugitive emissions components. There are some emissions that would be generated by contractors conducting the OGI camera monitoring associated with driving to and from the site for the fugitive emissions survey. Using AP–42 mobile emission factors and assuming a distance of 70 miles to the well site, the emissions generated from semiannual monitoring at a well site (140 miles to and from the well site twice a year) is estimated to be 0.35 lb/yr of hydrocarbons, 6.0 lb/yr of CO and 0.40 lb/yr of NO_x. No other secondary impacts are expected. We do not believe these secondary emissions are so significant as to affect the proposed determinations described above.

In summary, based on the analysis described above, the EPA is proposing OGI monitoring based on tiered total site-wide baseline methane emission levels to represent thresholds that would determine the monitoring frequency. For well sites with total site-level methane emissions less than 3 tpy,

[242] Percentage estimated using the analysis underpinning the baseline scenario in the RIA for the 2030 analysis year.

the EPA is proposing to require a one-time survey to demonstrate that the well site is free of leaks or other abnormal conditions that are not accounted for in the baseline calculation. For well sites with total site-level methane emissions of 3 tpy or greater, the EPA is proposing quarterly monitoring at all sites. Lastly, the EPA is co-proposing semiannual monitoring for well sites with total site-level methane emissions of 3 tpy or greater and less than 8 tpy, and quarterly monitoring for all sites with baseline emissions of 8 tpy or greater. As noted earlier, site-level baseline emission levels would be calculated by owners and operators for each site based on prescribed population emission factors for components and equipment at the site, combined with an assessment of potential methane emission from storage vessels (after applying controls).

b. Fugitive Emissions From Compressor Stations

The EPA continues to utilize the model plant approach in estimating baseline fugitive emissions from compressor stations. Unlike well sites, we believe that compressor station designs are less variable and that model plants are an effective construct to analyze fugitive emission control programs. The EPA has evaluated feedback received from several industry stakeholders related to development of compressor station model plants over multiple years since the original 2015 NSPS OOOOa proposal were model plants for compressor stations (including those at gathering and boosting stations, transmission stations, and storage facilities) were first introduced. Consistent with this early approach for estimating emissions from compressor stations, the EPA still believes the model plant approach is the best way to assess fugitive emissions from compressor stations, in the absence of information indicating otherwise. Baseline model plant emissions for compressor stations can reasonably be calculated using equipment counts, fugitive emissions component counts, and emissions factors from the 1995 Emissions Protocol. The EPA has evaluated each specific model plant for gathering and boosting, transmission, and storage, based on information that has become available, and model plants were updated where information indicated an update was appropriate. For example, information from actual compressor stations in operation provided by GPA Midstream for several of their member companies representing numerous sites across the country, was used to refine the gathering and boosting model plant in 2020. Refinements have also been made to the transmission and storage model plants based on information received from companies in these segments. The size and equipment located at compressor stations do not vary as widely as at well sites, and therefore emissions are expected to be less variable as well. Furthermore, stakeholders have not indicated that a model plant approach is not reasonable. For these reasons, the EPA retains a model plant approach for compressor stations which are representative in estimating fugitive emissions.

There are three types of compressor stations in the Crude Oil and Natural Gas source category: (1) Gathering and boosting stations, (2) transmission stations, and (3) storage stations. The equipment associated with these compressor stations vary depending on the volume of natural gas that is transported and whether any treatment of the gas occurs, such as the removal of water or hydrocarbons. The model plants developed for these sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) and associated components (*e.g.,* valves and connectors) that may be sources of fugitive emissions associated with these operations. One model plant was developed for each of the three types of compressor stations described above, which are discussed in detail in the 2020 NSPS OOOOa TSD and in the NSPS OOOOb and EG TSD supporting this action. For gathering and boosting stations, the fugitive baseline emissions were estimated to be 16.6 tpy of methane and 4.6 tpy of VOC. For transmission stations, the fugitive baseline emissions were estimated to be 40.4 tpy of methane and 1.1 tpy of VOC. For storage stations, the fugitive baseline emissions were estimated to be 142.2 tpy of methane and 3.9 tpy of VOC.

As with well sites, in the original BSER analysis for the 2016 NSPS OOOOa rulemaking, two options for reducing fugitive methane and VOC emissions at compressor stations were identified, which were (1) a fugitive emissions monitoring program based on individual component monitoring using EPA Method 21 for detection combined with repairs and (2) a fugitive emissions monitoring program based on the use of OGI detection combined with repairs. Finding that both methods achieve comparable emission reduction but OGI was more cost effective, the EPA ultimately identified quarterly monitoring of compressor stations using OGI as the BSER. 81 FR 35862. While there are several new fugitive emissions technologies under development, the EPA needs additional information and better understanding of these technologies, and they are therefore not being evaluated as potential BSER at this time. For this analysis for both the NSPS and the EG, we re-evaluated OGI as BSER. In the discussion below, we evaluate OGI control options based on varying the frequency of conducting the survey and fugitive emissions repair threshold (*i.e.,* the visible identification of methane or VOC when an OGI instrument is used). For this analysis, we considered annual, semiannual, quarterly, and monthly survey frequency for compressor stations.

In 2015, we evaluated the potential emission reductions from the implementation of an OGI monitoring program where an emission reduction of 40, 60 and 80 percent for annual, semiannual, and quarterly monitoring survey frequencies, respectively, were determined appropriate. No other information reviewed since 2015 indicates that the assigned reduction frequencies are different than previously established and the reduction efficiencies are consistent with what current information indicates. In addition, we also evaluated monthly monitoring for compressor stations where information evaluated indicated monthly OGI monitoring has the potential of reducing emissions up towards 90 percent.

We evaluated the costs of monitoring and repair under various monitoring frequencies described above, including the cost of OGI monitoring via the camera survey, repair costs, resurvey costs, monitoring plan development and the cost of a recordkeeping system. For compressor stations, the capital cost associated with the fugitives monitoring program were estimated to be $3,090 for each gathering and boosting compressor station, which includes development of a fugitive emissions monitoring plan for a company-defined area (assumed to include 7 gathering and boosting compressor stations) and database management development or licensing for recordkeeping. These capital costs are divided evenly amongst the 7 gathering and boosting compressor stations in the company-defined area for purposes of the model plant analysis, consistent with the 2016 NSPS OOOOa and 2020 Technical Rule analyses. The capital cost associated with the fugitives monitoring program for transmission and storage compressor stations was estimated at $23,880, which is for a single transmission and storage compressor station. The annual costs include the capital recovery cost (calculated at a 7 percent interest rate for 10 years), survey and repair costs, database management fees, and recordkeeping and reporting costs. The annual costs estimated for compressor stations range from $6,350 for annual monitoring to $33,220 for monthly monitoring at gathering and boosting compressor stations. For transmission compressor stations, the annual costs estimated range from $12,900 for annual monitoring to $39,770 for monthly monitoring. For storage compressor stations, the annual costs estimated range from $17,000 for annual monitoring to $43,860 for monthly monitoring.

As discussed above, the EPA is proposing that natural gas-driven intermittent vent controllers at production and natural gas transmission sites in Alaska without electricity would be subject to a standard that prohibits emissions when the controller is idle. Intermittent pneumatic controllers are designed to vent during actuation only, but these devices are known to malfunction and operate incorrectly which causes them to release natural gas to the atmosphere when idle. For sites in Alaska that do not have electricity located in the production segment (well sites, gathering and boosting stations, and centralized tank batteries) and in the transmission and storage segment, the EPA is proposing to define intermittent natural gas-driven pneumatic controllers as an affected facility and proposing to apply a standard that these controllers only vent during actuation and not when idle. See section XII.C on pneumatic controllers for a full explanation of this standard. We have determined that it would be efficient and reasonable to verify proper actuation and that venting does not occur during idle times by proposing that these devices are monitored along with fugitive emissions components at a site to ensure these devices are meeting the standard. We believe the cost of monitoring of intermittent pneumatic controllers will be absorbed by the cost of the fugitive emissions program, and that little to no additional cost would be associated with monitoring these devices on the fugitive emissions components monitoring schedule. If compressor stations have electricity, they would be required to have non-emitting controllers, and no additional costs are expected to be incurred relayed to repair and/or replacement of malfunctioning intermittent vent controllers.

At gathering and boosting compressor stations there are savings associated with the gas not being released. The value of the natural gas saved is assumed to be $3.13 per Mcf of recovered gas. Transmission and storage compressor stations do not own the natural gas; therefore, revenues from reducing the amount of natural gas emitted/lost was not applied for this segment.

The EPA evaluated the cost-effectiveness of monitoring for each sub-type of compressor station, starting with evaluating whether quarterly monitoring remains the BSER. The 2016 NSPS OOOOa requires a fugitive emissions monitoring and repair program, where compressor stations have to be monitored quarterly. Compressor stations have successfully met this standard. Further, several State agencies have rules that require quarterly monitoring at compressor stations. For example, Colorado's Regulation 7 Control of Ozone via *Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions* [243] requires a semiannual inspection frequency for compressor stations with uncontrolled actual VOC emissions between 2 and 12 tpy, a quarterly inspection frequency for compressor stations with uncontrolled actual VOC emissions between 12 and 50 tpy, and monthly inspections for compressor stations with uncontrolled actual VOC emissions above 50 tpy. California requires quarterly inspections under their LDAR requirements [244] and similarly, Ohio's General Permit 18.1 also requires quarterly monitoring for compressor stations.[245] These examples of State rules, where quarterly monitoring appears to be the lowest monitoring frequency required with one exception where the VOC baseline emissions were extraordinarily high, is a demonstration of the reasonableness of monitoring fugitive emissions components on a quarterly basis for compressor stations.

Given the apparent reasonableness of quarterly monitoring as discussed above, the EPA evaluated whether it was reasonable to require monthly monitoring for compressor stations. Table 16 summarizes the cost, emission reductions, and cost-effectiveness of quarterly and monthly OGI monitoring at compressor stations for the single pollutant approach, while Table 17 summarizes the multi-pollutant approach.

TABLE 16—SUMMARY OF THE SINGLE POLLUTANT COST OF CONTROL FOR COMPRESSOR STATION FUGITIVE EMISSIONS MONITORING

Model plant	Capital cost ($)	Annual cost ($/yr)	Annual cost w/savings ($/yr)	Emission reductions		Methane cost of control w/o savings ($/ton)	VOC cost of control w/o savings ($/ton)
				Methane (tons/yr)	VOC (tons/yr)		
Quarterly Monitoring							
Gathering & Boosting	$3,100	$13,400	$11,000	13.3	3.7	$1,000	$3,600
Transmission	23,900	19,900	19,900	32.3	0.9	600	22,300
Storage	23,900	24,000	24,000	114.0	3.2	200	7,600
Compressor Program Weighted Average						900	4,400
Monthly Monitoring							
Gathering & Boosting	3,100	33,200	30,500	15.0	4.2	2,200	8,000
Transmission	23,900	39,800	39,800	36.4	1.0	1,100	39,500
Storage	23,900	43,900	43,900	128.2	3.5	340	12,400
Compressor Program Weighted Average						1,800	9,300

[243] *https://cdphe.colorado.gov/aqcc-regulations.*

[244] *https://ww2.arb.ca.gov/sites/default/files/classic/regact/2016/oilandgas2016/ogfro.pdf.*

[245] *https://www.epa.state.oh.us/dapc/genpermit/ngcs/GP_181.*

TABLE 17—SUMMARY OF THE MULTI–POLLUTANT COST OF CONTROL FOR COMPRESSOR STATION FUGITIVE EMISSIONS MONITORING

Model plant	Capital cost ($)	Annual cost ($/yr)	Annual cost w/savings ($/yr)	Emission reductions		Methane cost of control w/o savings ($/ton)	VOC Cost of control w/o savings ($/ton)
				Methane (tons/yr)	VOC (tons/yr)		
Quarterly Monitoring							
Gathering & Boosting	$3,100	$13,400	$11,000	13.3	3.7	$500	$1,800
Transmission	23,900	19,900	19,900	32.3	0.9	300	11,100
Storage	23,900	24,000	24,000	114.0	3.2	100	3,800
Compressor Program Weighted Average						430	2,200
Monthly Monitoring							
Gathering & Boosting	3,100	33,200	30,500	15.0	4.2	1,100	4,000
Transmission	23,900	39,800	39,800	36.4	1.0	550	19,800
Storage	23,900	43,900	43,900	128.2	3.5	200	6,200
Compressor Program Weighted Average						900	4,600

Based on the single pollutant approach, both quarterly and monthly frequencies are reasonable for methane emissions, while only quarterly is reasonable for VOC emissions. Like described for well sites, owners and operators of compressor stations have been monitoring quarterly since 2016 pursuant to NSPS OOOOa, State requirements, or voluntarily, which suggests these costs are reasonable. These costs for quarterly monitoring are also comparable to those found reasonable in both the 2016 NSPS OOOOa and the 2020 Technical Rule. Further, both frequencies are reasonable under the multipollutant approach when considering the total cost-effectiveness compared to a baseline of no OGI monitoring.

The EPA then looked at the incremental costs of going from quarterly to monthly monitoring. Quarterly monitoring achieves an emission reduction ranging from 13.3 tpy at gathering and boosting compressor stations to 114 tpy at storage compressor stations. Monthly monitoring achieves additional reductions ranging from 1.7 tpy at gathering and boosting compressor stations to 14.2 tpy at storage compressor stations. However, these additional reductions are achieved at $9,400/ton methane (and nearly $50,000/ton VOC). The EPA finds that achieving these additional emissions reductions is not reasonable for the cost, given the only small fraction of additional reductions realized at monthly monitoring. Based on the cost analysis summarized above, we find that the cost effectiveness of quarterly monitoring for compressor stations is reasonable.

Finally, no secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of fugitive emissions components. There are some emissions that would be generated by the OGI camera monitoring contractors with respect to driving to and from the site for the fugitive emissions survey. Using AP–42 mobile emission factors and assuming a distance of 70 miles to the compressor station, the emissions generated from quarterly monitoring at a compressor station (140 miles to and from the compressor station four times a year) is estimated to be 0.70 lb/yr of hydrocarbons, 12.0 lb/yr of CO and 0.80 lb/yr of NO_X. No other secondary impacts are expected.

In light of the above, we find that the BSER for reducing methane and VOC emissions from all compressor stations, including gathering and boosting stations, transmission stations, and storage stations is quarterly monitoring for this proposal. Therefore, for NSPS OOOOb, we are proposing to require quarterly monitoring for all compressor stations.

2. EG OOOOc

The EPA also evaluated BSER for the control of fugitive emissions at existing well sites and compressor stations. The findings were that the controls evaluated for new sources for NSPS OOOOb are appropriate for consideration under the EG OOOOc. Further, the EPA finds that the OGI monitoring, methane emission reductions, costs, and cost effectiveness results discussed above for new sources are also applicable for existing sources.

Therefore, for the EG OOOOc, the EPA is proposing presumptive standards to require quarterly monitoring for well sites with site-level baseline methane emissions greater than and equal to 3 tpy. Further, we are co-proposing semiannual monitoring for well sites with site-level baseline methane emissions greater than and equal to 3 tpy and less than 8 tpy, and quarterly monitoring for well sites with site-level baseline methane emissions greater than and equal to 8 tpy. We find the costs reasonable for existing well sites with total site-level baseline methane emissions greater than or equal to 3 tpy to conduct quarterly OGI monitoring at an incremental cost of $1,700/ton methane reduced. We are aware that there is a large percentage of existing well sites that are likely owned and operated by small businesses. We continue to be concerned about the burden of frequent OGI monitoring on these small businesses and are requesting comment consistent with our solicitation for new sources.

The EPA also finds, and is proposing, that the BSER for reducing methane emissions from all existing compressor stations, including gathering and boosting stations, transmission stations, and storage stations is quarterly monitoring. For compressor stations, we find that both quarterly (at $430/ton methane reduced) and monthly monitoring (at $900/ton methane reduced) are reasonable when looking at total cost-effectiveness against a baseline of no monitoring, however, at an incremental cost of $9,400/ton methane reduced, monthly monitoring is not reasonable. Therefore, for the EG OOOOc, we are proposing a presumptive standard of quarterly monitoring for all compressor stations.

3. Alternative Screening Using Advanced Measurement Technology

As discussed throughout this preamble, the EPA recognizes the existence large emission events. In certain instances, these situations could be caused by severely and continuously leaking components that would be identified and corrected via the routine OGI-based periodic monitoring program, but only on a quarterly or semiannual basis. Moreover, some large emission events are intermittent and stochastic in nature and may not be identified via these OGI surveys. Since the 2016 NSPS OOOOa, significant strides have occurred in developing and deploying methane detection technologies that can detect fugitive emissions (especially large emission events) in a potentially faster and more cost-effective manner than traditional techniques such as OGI and EPA Method 21. The EPA has continued following the development of these technologies and their applications through various public programs, such as the DOE ARPA–E programs, which have focused on the development of cost-effective tools to locate and measure methane emissions. Additionally, the EPA has continued discussions with stakeholders, including academic researchers and private industry, as they develop and evaluate novel tools for the detection and quantification of methane emissions in the oil and gas sector. As noted in section VII.B, the EPA also held a two-day workshop in August 2021 to hear perspectives on these new technologies. Some of the promising technologies now emerging include, but are not limited to, fixed-base and open path sensor networks, unmanned aircraft systems (UAS) equipped with methane detection equipment, the use of high-end instruments for mobile measurements on the ground and in the air, and satellite observations with advanced optical techniques.

As the EPA learned during the Methane Detection Technology Workshop, industry has utilized these advanced measurement technologies to supplement existing fugitive emissions programs and to quickly identify unexpected emissions events (*e.g.,* emissions from controlled storage vessels) in order to make repairs as quickly as possible.[246] While most of these advanced measurement technologies are not sensitive enough to pin-point the exact same emission sources as the current fugitive emission detection programs, many can more quickly detect the largest emissions sources (*e.g.,* malfunctions and undersized or non-performing major equipment), and they can also find emissions that may be missed by fugitive emission surveys (*e.g.,* component-level leaks on valves, connectors, and meters). Moreover, the EPA understands the stochastic nature, distribution, and frequency of these large emission events across sites and over time is uncertain, and that these events occur sporadically at an individual site in ways that may take longer to detect or might not be detected through a periodic fugitive emissions survey using traditional technologies. Integrating advanced emission detection technologies into this rule—whether deployed by owner-operators themselves or by third parties—could be a valuable way to reduce fugitive emissions more cost-effectively and rapidly detect and remedy ''super-emitting'' events that make an outsize contribution to overall emissions from this source category.

There are many other advantages to these advanced measurement technologies over technologies currently used for fugitive emissions detection (*i.e.,* OGI and EPA Method 21 technologies). For instance, these advanced measurement technologies may be less susceptible to operator error or judgment than traditional methods of leak detection, thus making surveys more consistent and reliable. Many of these technologies can survey broader areas than can be effectively surveyed with field personnel, drastically reducing the driving time from site to site, which could have potential cost and safety benefits and allow for more frequent monitoring, which could allow for the identification and mitigation of large volume methane emissions sooner than OGI or EPA Method 21 surveys.

As described in section XI.A.5, the EPA is proposing an alternative work practice for detecting fugitive emissions that incorporates these advanced measurement technologies. There were a number of presentations during the Methane Detection Technology Workshop that discussed the detection capabilities of various methane measurement technologies which could be used for a screening approach. Given the diverse array of advanced technologies that are now in use, and the rapid pace at which these technologies are being refined and new technologies are being developed, the EPA believes that it is appropriate to articulate a foundational set of performance criteria and documentation requirements for this alternative work practice that can be applied to multiple existing and forthcoming technologies. Based on the information available to the Agency, including the information presented in the Methane Detection Technology Workshop, the EPA believes setting a minimum detection threshold of 10 kg/hr methane might be appropriate for use in determining what technologies and in what deployment platforms (*e.g.,* fixed, ground and aerial) are appropriate for a potential screening alternative within the proposed NSPS OOOOb and EG OOOOc. Therefore, the specific alternative work practice that the EPA is proposing includes a provision that would allow the use of any technology with a minimum detection threshold of 10 kg/hr.

Although we have focused this discussion on advanced measurement technologies, the EPA is also soliciting comment on whether there are ways to utilize existing technologies to screen for large emission events. For example, could gauges or meters be utilized to identify potential large losses between the wellhead and the custody meter assembly.

Further, the EPA is seeking comment on very simple AVO checks that could be performed in conjunction with the periodic OGI monitoring surveys to help identify potential large emission events. For example, two often-cited causes of super-emitter sources are unlit flares and separator dump valves that are stuck open allowing unintentional gas carry-through to emit from storage vessels. The additional time and cost required to perform visual inspections to see if the flare pilot light is working, or to see if a dump valve is stuck open, would be minimal. Yet the benefits of simple AVO inspections could be significant. The EPA is soliciting comment on this concept, as well as comments on the common items that could be included on a checklist for such low-burden AVO inspections in conjunction with fugitive monitoring.

B. Proposed Standards for Storage Vessels

1. NSPS OOOOb

a. Background

In the 2012 NSPS OOOO, the EPA established VOC standards for storage vessels. Based on our review of these standards, we are proposing to retain the current standard of 95 percent reduction. However, the EPA is proposing to redefine the affected facility to include a tank battery. Specifically, the EPA is proposing to define a storage vessel affected facility as a single storage vessel or a group of storage vessels that are physically adjacent and that receive fluids from the

[246] See summary report of the EPA's Methane Detection Workshop located at Docket ID No. EPA–HQ–OAR–2021–0317.

same source (*e.g.,* well, process unit, or set of wells or process units) or manifolded together for the transfer of liquid or vapors. In this definition, we consider tanks to be physically adjacent when they are near or next to each other and may or may not be connected or piped together. In addition, the EPA is proposing methane standards for new, reconstructed, and modified storage vessels under the proposed NSPS OOOOb. Both the proposed revised VOC standards and the proposed methane standards would be the same (*i.e.,* 95 percent reduction of emissions from storage vessel affected facilities as defined above in this proposal). These reductions can be achieved by utilizing a cover and closed vent system to capture and route the emissions to a control device that achieves an emission reduction of 95 percent, or by routing the captured emissions to a process.

Both methane and VOC emissions from storage vessels are a result of working, breathing and flashing losses. Working losses occur when vapors are displaced due to the emptying and filling of storage vessels. Breathing losses are the release of gas associated with daily temperature fluctuations when the liquid level remains unchanged. 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. Temperature of the liquid may also influence the amount of flash emissions. Lighter crude oils and condensate generally flash more hydrocarbons than heavier crude oils.

b. Definition of Affected Facility

The current standards 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. 76 FR 52738, 52763 (Aug. 23, 2011). Further, the 6 tpy applicability threshold was established by directly correlating VOC emissions to throughput, was based on the use of a single 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. Over the years, there have been questions and issues raised regarding how to calculate the potential VOC emissions from individual storage vessels that are part of a tank battery. The EPA attempted to address this issue through various amendments to NSPS OOOO and NSPS OOOOa,[247] most recently in the 2020 Technical Rule. In the 2020 Technical Rule, the EPA continued to recognize that tank batteries are more prevalent than individual storage vessels. While the 2020 Technical Rule included amendments to the calculation methodology for determining potential VOC emissions from storage vessels that are part of a tank battery, the EPA has now determined that it is more appropriate to evaluate the control of methane and VOC emissions from tank batteries[248] as a whole instead of each individual storage vessel within a tank battery.[249] In this review the EPA evaluated regulatory options based on the use of a single control device to reduce both methane and VOC emissions from a tank battery, which is consistent with the 2012 NSPS OOOO, 2016 NSPS OOOOa, and subsequent amendments to each of those rules. The EPA believes that this approach will simplify applicability criteria for owners and operators of storage vessels, and more accurately aligns with the EPA's original intent of how storage vessel affected facility status should be determined.

c. Modification

Section 60.14(a) of the general provisions to part 60 defines modification as follows: ''Except as provided in paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification. . . .'' We also note that 40 CFR 60.14(f) states that ''Applicable provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.'' The EPA understands the difficulty assessing emissions from storage vessels and seeks to provide clarity on actions that are considered modification of a tank battery by explicitly listing these in the proposed NSPS OOOOb. We evaluated circumstances that would lead to an increase in the VOC and methane emissions from a tank battery and therefore constitute a modification of an existing tank battery. A modification of an existing tank battery would then require the tank battery owner or operator to assess the potential emissions relative to the proposed NSPS instead of the EG.

The EPA is proposing that a single storage vessel or tank battery is modified when any of the following physical or operational changes are made: (1) The addition of a storage vessel to an existing tank battery; (2) replacement of a storage vessel such that the cumulative storage capacity of the existing tank battery increases; and/or (3) an existing single storage vessel or tank battery that receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput (from actions such as refracturing a well or adding a new well that sends these liquids to the tank battery). For both items 1 and 2, even if the type and quantity of fluid processed remains the same, the increased storage capacity will lead to higher breathing losses and thereby increase the VOC emissions from the tank battery relative to the VOC emissions prior to the vessel addition or replacement. Therefore, we conclude that these actions are a modification of the tank battery. However, we are soliciting comment to help us better understand the effect of the proposed definition number 1 and 2 on the number of new storage vessels or tank batteries that would be subject to the NSPS. Under the current definition of a storage vessel affected facility in NSPS OOOOa, which is each single storage vessel that meets the 6 tpy applicability threshold, a new storage vessel that is installed in an existing tank battery is an affected facility (assuming the 6 tpy applicability threshold is met for the single storage vessel) whether the new storage vessel is a replacement or an addition to the tank battery. However, under the proposed definition number 1 and 2 above, the NSPS OOOOb is triggered only if the new storage vessel is an addition to the tank battery or is of bigger capacity than the storage vessel it is replacing in a tank battery. We therefore solicit comment on how often a storage vessel in a tank battery is replaced with one that is of bigger capacity, or whether the need to increase a tank battery's capacity is

[247] See 79 FR 79018 and 80 FR 48262.

[248] For purposes of this analysis and the resulting proposed standards, the term ''tank battery'' refers to a single storage vessel or a group of storage vessels that are physically adjacent and that receive fluids from the same source (*e.g.,* well, process unit, or set of wells or process units) or which are manifolded together for liquid or vapor transfer.

[249] This approach would no longer allow facilities to apply certain criteria and average the total potential VOC emissions of the tank battery across the number of storage vessels in the battery to determine a per-vessel potential for VOC emissions.

generally accomplished by adding storage vessels as opposed to replacing an existing one with a bigger one. We further solicit comment on whether, under our proposed definition of a tank battery (*i.e.,* a single storage vessel or a group of storage vessels that are physically adjacent and that receive fluids from the same source (*e.g.,* well, process unit, or set of wells or process units)), the replacement of a storage vessel in a tank battery should also require the assessment of the potential VOC and methane emissions from the tank battery.

Item 3 will increase the volumetric throughput of the tank battery relative to the throughput prior to storage of the additional fluid. This will increase the working losses and potentially increase the flashing losses from the tank battery, depending on the properties of the new fluid stream. In any event, adding a new fluid stream to an existing tank battery increases the VOC emissions from that tank battery relative to just prior to the addition of a new fluid stream and is therefore considered a modification of the tank battery.

The EPA is proposing to require that the owner or operator recalculate the potential VOC emissions when any of these actions occur on an existing single storage vessel or tank battery to determine if the modification may require control of VOC emissions. The existing single storage vessel or tank battery will only become subject to the proposed NSPS if it is modified pursuant to this proposed definition of modification and its potential VOC emissions exceed the proposed 6 tpy VOC emissions threshold for the tank battery.

d. Technology Review

The available control techniques for reducing methane and VOC emissions from storage vessels include routing the emissions from the storage vessels to a combustion control device or a VRU, which would route the emission to a process (including a gas sales line). These are the same control systems that were evaluated under the 2012 NSPS OOOO. While floating roofs can also be used to reduce emissions from many storage vessel applications, including at natural gas processing plants and compressor stations, floating roofs are not effective at reducing emissions from storage vessels that have flashing losses (*e.g.,* storage vessels at well sites or centralized production facilities). Besides the control options described above, we did not find other available control options through our review, including review of the RACT/BACT/LAER Clearinghouse.

In the development of the 2012 NSPS OOOO, we found that using either a VRU or a combustion control device could achieve a 95 percent or higher VOC emission reduction efficiency. Available information since then continues to support that such devices can achieve a 95 percent control efficiency for both methane and VOC emissions. We are not proposing to require higher control efficiency because, in order to achieve a minimum of 95 percent control efficiencies on a continuous basis, operators will need to design and operate the control to achieve greater than 95 percent. Thus, while the control device may commonly operate at greater than 95 percent control efficiencies, there may be process fluctuations in heat loads, inlet backpressure, and other variables that may affect performance that may lower the control efficiencies achieved. For example, there are field conditions, such as high winds that may influence combustion efficiencies.[250] We also note that, while the EPA established operating and monitoring requirements to ensure flares achieve a 98 percent control efficiency at petroleum refineries in 40 CFR part 63, subpart CC, these requirements include sophisticated monitoring and operational controls and tend to lead to additional fuel use and greater secondary impacts than combustion systems targeting to achieve a minimum of 95 percent control efficiency. Considering these factors, we conclude that, consistent with CAA section 111(a) definition of a ''standard of performance,'' 95 percent control efficiency as the minimum allowable control efficiency at any time continues to reflect ''the degree of emission limitation achievable'' through the application of the BSER for tank batteries (a combustor or a VRU). We solicit comment on the issues described above for requiring higher than 95 percent reduction.[251]

During pre-proposal outreach, some small businesses raised a concern that the NSPS OOOOa requirement for a continuous pilot light for a storage vessel control device generated more emissions than it prevented for storage vessels with low emissions. Specifically, small business representatives raised concerns that there are situations where propane or other fossil fuel must be used to maintain continuous pilot lights for flares used as control devices on storage vessels that do not produce enough emissions. The EPA is interested in whether the benefits of reducing emissions with these control devices are negated by the need to burn additional fossil fuels and whether there are additional factors that lead to variability in emissions from storage vessels that could be used to more narrowly target these requirements to limit the unnecessary operation of flares. We are soliciting comment from all stakeholders on this issue.

e. Control Options and BSER Analysis

For this proposal, the EPA evaluated regulatory options based on different potential emissions thresholds for VOC and methane. We assumed the potential tank battery emissions were reduced by 95 percent using either a VRU or a combustion control device. Since VRUs recover saleable products, we also estimated the value of the recovered product when VRUs were used. The EPA encourages the use of VRUs to capture and sell the emissions from the storage vessels by classifying VRUs as part of the process, therefore emission recovered would not be included in the potential emissions at a site.

For new, modified, or reconstructed sources, we evaluated the cost of control using a single combustion device (or VRU) on a single storage vessel as well as a tank battery made up of multiple storage vessels. To do this, we evaluated the use of a single control device achieving 95 percent reduction of VOC and methane emissions at the following potential emission thresholds: 6 tpy VOC from a single storage vessel; 3 and 6 tpy VOC from a tank battery; and 1.3 tpy, 5.3 tpy, 20 tpy, and 50 tpy methane from a tank battery. Based on our cost analysis we propose to retain the 6 tpy applicability threshold.

The estimated all-in capital costs for a single combustion control device are approximately $80,000. The estimated annualized costs include the capital recovery cost (calculated at a 7 percent interest rate for 15 years) and labor costs for operations and maintenance and are estimated at approximately $31,500/yr. The estimated capital costs for a VRU sized for a source with potential VOC emissions of 6 tpy are approximately $32,000 and the estimated annualized costs are estimated at approximately $24,000/yr not considering any potential recovery credits from sales. More information on this cost analysis

[250] EPA. April 2012. *Parameters for Properly Designed and Operated Flares.* Prepared for U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC.

[251] Further, in section XIII.E (solicitation of comment on control device efficiency), the EPA solicits comment on the level of reduction that can be reliably achieved using a flare and what measures need to be in place to assure such reduction.

is available in the NSPS OOOOb and EG TSD for this proposal.

Based on our analysis, the cost effectiveness of controlling VOC and methane emissions from a tank battery with the potential for VOC emissions of 6 tpy, under the single pollutant approach where all the costs are assigned to the reduction of VOC, is $5,540 per ton of VOC eliminated assuming the use a single combustion control device. As explained above, storage vessels are commonly located adjacent to one another as part of tank battery, which allows the vapors from the storage vessels within the tank battery to be collected and routed to a single control device, when one is used. The single pollutant cost effectiveness for a VRU to control a tank battery with potential VOC emissions of 6 tpy is approximately $4,000 per ton of VOC eliminated. As shown in section IX, costs ranging from $4,000 to $5,540 per ton of VOC reduced are within the range that the EPA considers to be cost effective for reducing VOC emissions. Because it is cost effective to reduce the VOC emissions from a tank battery with potential VOC emissions of 6 tpy or greater, one of the two targeted pollutants in this action, it is cost effective to reduce both VOC and methane emissions from a single storage vessel or a tank battery at that level. Based on our estimate, a tank battery with potential 6 tpy VOC emissions has potential 1.3 tpy of methane emissions. Because storage vessels contain crude oil, condensate, intermediate hydrocarbons, or produced water, which are approximately 80 percent VOC, the methane emissions from storage vessels are generally less than the VOC emissions.

We also evaluated the cost effectiveness at a lower VOC threshold of 3 tpy. As shown in the NSPS OOOOb and EG TSD, the single pollutant cost effectiveness for controlling a tank battery with potential emissions of 3 tpy ranges from $7,500 to $11,000. As shown in section IX, costs ranging from $7,500 to $11,000 per ton of VOC reduced is not within the range that the EPA considers to be cost effective for reducing VOC emissions. Using the multipollutant approach, the VOC cost effectiveness is between $3,800 and $5,500, which is considered reasonable, but the methane cost effectiveness is between $17,000 and $25,000 for any of the methane thresholds assessed in conjunction with 3 tpy VOC limit, which is considered unreasonable. Therefore, the 3 tpy VOC control option was not considered reasonable at this time using either the single pollutant or multipollutant approach.

Our analysis also shows that, under the single pollutant approach where all the costs are assigned to the reduction of methane and zero to VOC, it is cost effective to control a single storage vessel or a tank battery with potential methane emissions of 20 tpy (at costs ranging from $1,250 to $1,660 per ton methane). Based on our estimate, a tank battery with potential methane emissions of 20 tpy would have the potential VOC emissions of 91 tpy, 95 percent of which would be reduced at zero cost. Under the multipollutant cost-effectiveness approach, where half of the cost is allocated to methane reduction and the other half to VOC reduction, it is cost effective to control a tank battery with potential methane emissions of 10 tpy and corresponding potential VOC emissions of 46 tpy, at an average cost of $1,500 per ton methane reduced and $330 per ton VOC reduced. In light of the above, 6 tpy of VOC is the lowest threshold that is cost effective to control both VOC and methane emissions. Therefore, the EPA is proposing to define the affected facility for purposes of regulating both VOC and methane emissions as a tank battery with potential VOC emissions of 6 tpy or greater.

2. EG OOOOc

The EPA is proposing presumptive standards for reducing methane emissions from existing storage vessels. For purposes of the EG, we are proposing to define a designated facility as a single storage vessel or tank battery with the potential for methane emissions of 20 tpy or greater. For purposes of the EG, we are proposing the same definition of a storage vessel affected facility, which is a single storage vessel or a group of storage vessels that are physically adjacent and that receive fluids from the same source (*e.g.,* well, process unit, or set of wells or process units).

The available controls for reducing methane emissions from existing tank batteries are the same as those for reducing methane and VOC emissions from new, modified and reconstructed tank batteries. In assessing the control costs for existing sources, we applied a 30 percent retrofit factor to the capital and installation costs to account for added costs of manifolding existing storage vessels and installing the control system on an existing tank battery. When applying controls to new sources, there is limited additional costs in designing the fixed roof with fittings to manifold the vapors and installing the closed vent piping or ducts during the tank installation process. For existing sources, installing fittings on an existing tank may require special lifts to access the roof and cut new ports in the roof. This may also require the tank to be taken out of service to conduct these installations, which requires additional time and labor. Additionally, when installing controls as part of the design for a new source, the facility layout can be designed to accommodate the control systems near the tank battery and the control device can be installed with the same crew installing the storage vessels, minimizing additional installation costs. For existing sources, there may be other equipment near the tanks that may require the control equipment to be further from the tank battery, which increases materials and installation costs. Also, control equipment costs will include the full costs of crew mobilization. Therefore, it is more expensive to install controls at an existing tank battery than to install controls as part of a new tank battery. We considered the same regulatory options based on potential methane emissions thresholds of 1.3 tpy, 5.3 tpy, 20 tpy, and 50 tpy per tank battery.

The estimated capital costs for a single combustion control device for emissions in this range are approximately $103,000. The estimated annual costs include the capital recovery cost (calculated at a 7 percent interest rate for 15 years) and labor costs for operations and maintenance and are estimated at approximately $34,000. The costs for VRU are more variable than combustion control systems and dependent on the potential emissions for which the VRU is designed to recover. The estimated capital costs for a VRU sized for a source with potential methane emissions of 20 tpy device are approximately $106,000 and the estimated annualized costs are approximately $49,000/yr not considering any potential recovery credits. With a VRU, the recovered VOC and methane are recovered as salable products. Considering the value of recovered product, the annualized cost for VRU sized to recover potential methane emissions of 20 tpy is estimated to be $26,000/yr. More information on this cost analysis is available in the NSPS OOOOb and EG TSD for this proposal.

The resulting cost effectiveness, for the application of a single combustion control device or VRU to achieve a 95 percent emission reduction ranges from $19,000 to $27,400 per ton of methane eliminated at a threshold of 1.3 tpy methane. This cost is not considered reasonable. Next, we evaluated the cost effectiveness at a methane threshold of 5.3 tpy, which ranged from $10,000 to $13,700 per ton of methane reduced, which is also not considered reasonable. At a threshold of 20 tpy methane, the cost effectiveness ranges from $1,400 to $1,800 per ton methane reduced. At a threshold of 50 tpy methane, the cost effectiveness ranges from $340 to $720 per ton methane reduced. When we considered the application of these options at a national level, the overall cost effectiveness of the 20 tpy potential methane emissions threshold was $400 per ton methane reduced without considering product recovery credits and has a net cost savings considering product recovery credits. Additionally, the incremental cost effectiveness of the 20 tpy option relative to the 50 tpy potential methane emissions threshold was approximately $900 per ton additional methane reduced when considering product recovery credits.

Based on the cost analysis summarized above, we find that the cost effectiveness for achieving 95 percent emission reduction of methane from a tank battery with potential methane emissions of 20 tpy is reasonable for methane. A cost-effective value of $1,800/ton of methane reduction is comparable to the estimated methane cost-effectiveness values for the controls identified as BSER for the 2016 NSPS OOOOa and which we consider to be representative of reasonable control cost for reducing methane emissions from the Crude Oil and Natural Gas source category, as explained in section IX.B. We further note that both California and Colorado require 95 percent reduction of methane (California) and hydrocarbon (Colorado) emissions from storage vessels. For California, existing separator and tank systems with an annual emission rate greater than 10 tpy methane must control emissions using a vapor collection system that reduces emissions by at least 95 percent.[252] For Colorado, storage vessels that emit greater than or equal to 2 tpy of actual uncontrolled VOC emissions must reduce VOC emissions by 95 percent.[253] These requirements, which are comparable to the proposed presumptive standards, are further indication that the cost of implementing the proposal is reasonable and not excessive.

[252] See sections 95668 and 95671 of California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4.

[253] See section I.D.3.a of Colorado Department of Public Health and Environment, ''Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions (Emissions of Volatile Organic Compounds and Nitrogen Oxides), Regulation Number 7'' (5 CCR 1001–9), July 2021.

3. Legally and Practicably Enforceable Limits

In addition to the BSER analysis described above, the EPA is clarifying the term ''legally and practicably enforceable limits'' as it related to storage vessel affected facilities in the proposed NSPS OOOOb and EG OOOOc. In the 2016 NSPS OOOOa, the EPA stated that ''any owner or operator claiming technical infeasibility, nonapplicability, or exemption from the regulation has the burden to demonstrate the claim is reasonable based on the relevant information. In any subsequent review of a technical infeasibility or nonapplicability determination, or a claimed exemption, the EPA will independently assess the basis for the claim to ensure flaring is limited and emissions are minimized, in compliance with the rule.'' See 81 FR 35824, 35844 (June 3, 2016).

In the context of storage vessels under both the 2012 NSPS OOOO and 2016 NSPS OOOOa, the EPA has learned that numerous owners and operators claim that their storage vessels are not affected facilities under 40 CFR 60.5365(e) and 40 CFR 60.5365a(e). This claim is made based on a determination that the potential for VOC emissions is less than 6 tpy when taking into account requirements under a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, State, local or Tribal authority.[254] However, when the EPA has reviewed the limits considered by these facilities as legally and practicably enforceable, we have become aware that the limits do not require a reduction in emissions; they are often self-imposed or of such a general nature as to be unenforceable or otherwise lack measures to assure the required emission reduction. For example, a permit contains an emission limit of 2 tpy for a single storage vessel, but does not contain any performance testing requirements, continuous or other monitoring requirements, recordkeeping and reporting, or other requirements that would ensure that emissions are maintained below the emissions limit in the permit. In *National Mining Ass'n* v. *EPA,* 59 F.3d 1351 (D.C. Cir. 1995), the court explained what constitutes ''effective'' control in assessing a source's potential to emit. According to the court, while ''effective'' controls need not be Federally enforceable, ''EPA is clearly not obliged to take into account controls that are only chimeras and do not really restrain an operator from emitting pollution.'' *Id.* at 1362. The court also emphasized that these non-Federally enforceable controls must stem from state or local government regulations, and not ''operational restrictions that an owner might voluntarily adopt.'' *Id.* at 1362. Further, as a general ''default rule,'' the burden of proof falls ''upon the party seeking relief.'' *Schaffer ex rel. Schaffer* v. *Weast,* 546 U.S. 49, 57–58, 126 S.Ct. 528, 163 L.Ed.2d 387 (2005).

[254] 40 CFR 60.5365(e) and 40 CFR 60.5365a(e)(1) and (2) allow owners and operators to take into account these requirements when calculating the potential VOC emissions.

In light of the above, the EPA is proposing to include a definition for a ''legally and practicably enforceable limit'' as it relates to limits used by owners and operators to determine the potential for VOC emissions from storage vessels that would otherwise be affected facilities under these rules. The intent of this proposed definition is to provide clarity to owners and operators claiming the storage vessel is not an affected facility in the Oil and Gas NSPS due to legally and practicably enforceable limits that limit their potential VOC emissions below 6 tpy. This definition is being proposed for NSPS OOOOb and the proposed presumptive standard included in EG OOOOc. This proposed definition of ''legally and practicably enforceable limit'' is consistent with the EPA's historic position on what is considered ''legally and practicably enforceable,'' as tailored to storage vessels in the oil and gas sector that would otherwise be affected facilities under these rules. The proposed definition is as follows:

''For purposes of determining whether a single storage vessel or tank battery is an affected facility, a legally and practicably enforceable limit must include all of the following elements:

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

ii. an averaging time period for the production limit in (i) (if a production-based limit is used) that is equal to or less than 30 days;

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

iv. ongoing monitoring of the parametric limits in (iii) that demonstrates continuous compliance with the production and/or operational limit(s) in (i);

v. recordkeeping by the owner or operator that demonstrates continuous compliance with the limit(s) in (i–iv); and

vi. periodic reporting that demonstrates continuous compliance.''

In this proposed definition, the EPA is not addressing the various ways in which a State or other authority's permit may be issued since the format of permit issuances varies by jurisdiction. The proposed definition of ''legally and practicably enforceable'' does not specify limits, monitoring requirements, or recordkeeping. Instead, the owner or operator should work with the permitting authority to establish specific limits, monitoring requirements and recordkeeping that will ensure any permitted emission limit is achieved. Only those limits that include the elements described above will be considered ''legally and practicably enforceable'' for purposes of determining the potential for VOC emissions from a single storage vessel or tank battery, and thus applicability (or non-applicability) of each single storage vessel or tank battery as an affected facility under the rule.

This proposed definition will provide clarity to owners and operators in what limits are necessary to ensure they have appropriately determined their single storage vessels or tank batteries are affected facilities under the proposed NSPS OOOOb or designated facilities under the proposed EG OOOOc. Further, as stated in the 2016 NSPS OOOOa, well-designed rules ensure fairness among industry competitors and are essential to the success of future enforcement efforts. 81 FR 35844 (June 3, 2016). The EPA is soliciting comment on this proposed definition from all stakeholders.

C. Proposed Standards for Pneumatic Controllers

1. NSPS OOOOb

a. Background

In the 2012 NSPS OOOO, the EPA established VOC standards for natural gas-driven pneumatic controllers. Specifically, subpart OOOO established a natural gas bleed rate limit of 6 scfh for individual, continuous bleed, natural gas-driven controllers located in the production segment. Continuous bleed, natural gas-driven controllers with a bleed rate of 6 scfh or less are commonly called ''low bleed'' controllers. However, that rule also allowed for the use of ''high bleed'' controllers (those with a bleed rate over 6 scfh) where required by functional needs such as response time, safety, and positive actuation. At natural gas processing plants, subpart OOOO implemented a VOC standard that required a bleed rate of zero (''zero bleed'' or ''no bleed''). The rule also included allowances for the use of continuous bleed natural gas-driven controllers at natural gas processing plants where required by functional needs.

In the 2016 NSPS OOOOa, the EPA extended the 6 scfh natural gas bleed rate standard to the natural gas transmission and storage segment and established GHG standards for all segments. Effectively, the 2016 NSPS OOOOa required low bleed controllers to reduce methane and VOC emissions from the production and transmission and storage segments and required a bleed rate of zero for pneumatic controllers at natural gas processing plants. Like the 2012 NSPS OOOO, the 2016 NSPS OOOOa included allowances for the use of continuous high bleed controllers in the production and transmission and storage segments and continuous natural gas-driven pneumatic controllers at natural gas processing plants where required by functional needs.

Emissions from natural gas-driven intermittent vent pneumatic controllers were not addressed in either the 2012 NSPS OOOO or the 2016 NSPS OOOOa. This was because, when operated and maintained properly, methane and VOC emissions from intermittent controllers are substantially lower (by an order of magnitude) than emissions from other types of natural gas-driven controllers. However, the EPA is now aware that these intermittent controllers often malfunction and vent during idle periods. Emissions factors considering this fact are around four times higher than the factors for low-bleed controllers. Further, as presented in subsection c of this section, methane emissions from intermittent controllers make up a significant portion of the overall methane emissions from all natural gas and petroleum system sources in the GHGI. As such, the EPA is now proposing to reduce emissions from intermittent controllers via NSPS OOOOb.

b. Affected Facility Definitions and Zero Emissions Standard

As a result of the review of these requirements in the 2016 NSPS OOOOa, the previous BSER determinations, and the consideration of new information, including State regulations that have been enacted since 2016, the EPA is proposing GHG (methane) and VOC standards for natural gas-driven pneumatic controllers in all segments of the industry included in the Crude Oil and Natural Gas source category (*i.e.,* production, processing, transmission and storage).

First, in terms of the definition of an affected facility, the EPA is proposing to revise the types of pneumatic controllers that are affected facilities to include both continuous bleed controllers and intermittent vent controllers. For continuous bleed controllers, an affected facility is each single continuous bleed natural gas-driven pneumatic controller that vents to the atmosphere. For intermittent vent controllers, an affected facility is each single natural gas-driven pneumatic controller that is not designed to have a continuous bleed rate but is designed to only release natural gas to the atmosphere as part of the actuation cycle. These affected facility definitions apply for pneumatic controllers in both the production and transmission and storage segments, as well as for those at natural gas processing plants.

Next, in terms of standards, we are proposing a requirement that all controllers (continuous bleed and intermittent vent) in the production and natural gas transmission and storage segments must have a methane and VOC emission rate of zero. Controllers that emit zero methane and VOC to the atmosphere can include, but are not limited to, air-driven pneumatic controllers (also referred to as instrument air-driven or compressed air-driven controllers), mechanical controllers, electronic controllers, and self-contained natural gas-driven pneumatic controllers. While these ''zero-emissions controllers'' would not technically be affected facilities because they are not driven by natural gas (air-driven, mechanical, and electronic) or because they do not vent to the atmosphere, owners and operators should maintain documentation if they would like to be able to demonstrate to permit writers or enforcement officials that there are no methane or VOC emissions from the controllers and that these controllers are not affected facilities and are not subject to the rule. The proposed standard would apply to both continuous bleed and intermittent vent controllers at these sites.

For all natural gas processing plants, we are proposing to essentially retain the 2016 NSPS OOOOa standard that requires that controllers must have a methane and VOC emission rate of zero (*i.e.,* zero-emissions controllers must be used). However, we are proposing to slightly change the wording of the standard from subparts OOOO and OOOOa, which require a ''bleed rate of zero.'' Many natural gas processing plants use pneumatic controllers that are powered by compressed air, which can technically have a compressed air bleed rate greater than zero. Put another way, some controllers that are powered with compressed air can allow some of that compressed air to leave the controller and thus be released into the atmosphere (they can ''bleed'' compressed air). However, since the compressed air does not contain any natural gas, methane, or VOC, we are clarifying the standard by proposing to require that pneumatic controllers at natural gas processing plants have a methane and VOC emission rate of zero.

In both NSPS OOOO and OOOOa, there is an exemption from the standards in cases where the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety, and positive actuation. The EPA is not maintaining this exemption in the proposed NSPS OOOOb, except for in very limited circumstances explained below. As discussed below, the reasons to allow for an exemption based on functional need in NSPS OOOO and OOOOa were based on the inability of a low-bleed controller to meet the functional requirements of an owner/operator such that a high-bleed controller would be required in certain instances. Since we are now proposing that pneumatic controllers have a methane and VOC emission rate of zero, we do not believe that the reasons related to the use of low bleed controllers are still applicable.

The proposed rule also does include an exemption from the zero-emission requirement for pneumatic controllers in Alaska at locations where electricity power is not available. In these situations, the proposed standards would require the use of a low-bleed controller instead of high-bleed controller. The proposed rule also includes the exemption for pneumatic controllers in Alaska at sites without power that would allow the use of high-bleed controllers instead of low-bleed based on functional needs. In addition, inspections of intermittent vent controllers to ensure they are not venting during idle periods described above would also be required at sites in Alaska without power.

c. Description

Pneumatic controllers are devices used to regulate a variety of physical parameters, or process variables, 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. Pneumatic controllers can be categorized based on the emissions pattern of the controller. Some controllers are designed to have the supply-gas provide the required pressure to power the end-device, and the excess amount of gas is emitted. The emissions of this excess gas are referred to as ''bleed,'' and this bleed occurs continuously. Controllers that operate in this manner are referred to as ''continuous bleed'' pneumatic controllers. These controllers can be further categorized based on the rate of bleed they are designed to have. Those that have a bleed rate of less than or equal to 6 scfh are referred to as ''low bleed,'' and those with a bleed rate of greater than 6 scfh are referred to as ''high bleed.'' Another type of controller is designed to release gas only when the process parameter needs to be adjusted by opening or closing the valve, and there is no vent or bleed of gas to the atmosphere when the valve is stationary. These types of controllers are referred to as ''intermittent vent'' pneumatic controllers. A third type of natural gas-driven controller releases gas to a downstream pipeline instead of the atmosphere. These ''self-contained'' types of controllers can be used in applications with very low pressure.

As discussed above, emissions from natural gas-powered pneumatic controllers occur as a function of their design. Self-contained controllers do not emit natural gas to the atmosphere. Continuous bleed controllers using natural gas as the power source emit a portion of that gas at a constant rate. Intermittent vent controllers using natural gas as the power source are designed to emit natural gas only when the controller sends a signal to open or close the valve, which is called actuation. From continuous bleed and intermittent vent controllers, another source of emissions is from improper operation or equipment malfunctions. In some instances, a low bleed controller may emit natural gas at a higher level than it is designed to do (*i.e.,* over 6 scfh) or an intermittent vent controller could emit continuously or near continuously rather than only during actuation.

Not all pneumatic controllers are driven by natural gas. At sites with power, electrically powered pneumatic devices or pneumatic controllers using compressed air can be used. As these devices are not driven by pressurized natural gas, they do not emit any natural gas to the atmosphere, and consequently, they do not emit VOC or methane to the atmosphere. In addition, some controllers operate mechanically without a power source or operate electronically rather than pneumatically. At sites without electricity provided through the grid or on-site electricity generation, mechanical controllers and electronic controllers using solar power can be used.

The emissions from natural gas-powered pneumatic controllers represent a significant portion of the total emissions from the Oil and Natural Gas Industry. In the 2021 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). The vast majority of these emissions are from natural gas-driven intermittent vent controllers, which the EPA is proposing to define as an affected facility for the first time in NSPS OOOOb. Of the combined methane emissions from pneumatic controllers in the petroleum systems and natural gas systems production segments, emissions from intermittent vent controllers make up 88 percent of the total. Continuous high bleed and low bleed controllers make up 8 and 4 percent, respectively.

d. Control Options

In identifying control options for this NSPS OOOOb proposal, we re-examined the options previously evaluated in the rulemakings to promulgate the 2012 NSPS OOOO and the 2016 NSPS OOOOa, and also examined State rules with requirements for pneumatic controllers that achieve emission reductions beyond those achieved by NSPS OOOOa. For NSPS subparts OOOO and OOOOa, we identified options for reducing emissions from continuous bleed natural gas-driven pneumatic controllers. These options included using low bleed controllers in place of high bleed controllers, enhanced maintenance (*i.e.,* periodic inspection and repair), and using zero-emissions controllers. For the production and transmission and storage segments, only the option to require low bleed controllers was fully analyzed in these previous analyses. Based on the EPA's determination at that time that electricity was ''likely unavailable'' at production and transmission and storage sites, the EPA did not fully consider instrument air or electronic controllers. The EPA also did not evaluate enhanced maintenance, as it was concluded that the highly variable nature of determining the proper methods of maintaining a controller could incur significant costs. The EPA did not evaluate options to reduce emissions from intermittent vent controllers in either the 2012 or 2016 NSPS.

Three U.S. States (California, Colorado, and New Mexico) and two Canadian provinces (Alberta and British Columbia) have rules or proposed rules that achieve emission reductions beyond those achieved by NSPS OOOOa. Starting on January 1, 2019, and subject to certain exceptions, a California rule requires that all new and existing continuous bleed devices must not vent natural gas to the atmosphere. The rule allows low bleed devices installed prior to January 1, 2016, to continue to operate, provided that annual testing is performed to verify that the low bleed rate is maintained. A Colorado rule adopted in February 2021, requires that all new controllers are no-bleed controllers (which includes self-contained natural gas-driven controllers), and over a period of two years, a sizeable portion of existing controllers must be retrofit to have a natural gas bleed rate of zero. New Mexico has proposed a rule that would require an emission rate of zero from all controllers located at sites with access to electrical power. The Canadian provinces of Alberta (effective 2022) and British Columbia (effective 2021) also regulate emissions from pneumatic controllers. In British Columbia, pneumatic devices that emit natural gas must not be used at new sources and at existing gas processing plants and large compressor stations, and in Alberta, owners and operators must prevent or control (by 95 percent) vent gas from new pneumatic controllers. While the terminology differs across these regulations, the EPA believes that all these requirements (with the exception of the 95 percent reduction requirement in Alberta) are very similar to if not the same as the zero methane and VOC emission requirement being proposed by the EPA for NSPS OOOOb.

From EPA's review of our past BSER analysis as well as reviewing these other rules, several options were identified for the BSER analysis for NSPS OOOOb to reduce methane and/or VOC emissions from natural gas-driven pneumatic controllers. These include the following: (1) Use of low bleed natural gas-driven pneumatic controllers in the place of high bleed natural gas-driven pneumatic controllers; (2) require zero emissions from intermittent vent controllers except during actuation, and (3) prohibit the emissions of methane and VOC from all pneumatic controllers (*i.e.,* establish a zero methane and VOC emission standard for both continuous bleed and intermittent bleed controllers).

e. 2021 BSER Analysis

Production and Transmission and Storage Segments

For production and transmission and storage sites, the EPA evaluated two options. The first was an option to require the use of low bleed natural gas-driven pneumatic controllers in the place of high bleed natural gas-driven pneumatic controllers, along with a requirement that natural gas-driven intermittent vent pneumatic controllers only discharge natural gas during actuation. We also evaluated an option of establishing a zero methane and VOC emissions standard, which we propose to determine represents the BSER for production and natural gas transmission and storage sites.

The first option evaluated was the use of low bleed natural gas-driven pneumatic controllers in the place of high bleed natural gas-driven pneumatic controllers. In the analysis of this option, we examined the emissions reduction potential, the cost of implementation, and the cost effectiveness in terms of cost per ton of emissions eliminated.

The emission reduction potential of using a low bleed controller in place of a high bleed controller depends on the actual bleed rate of each device, which varies from device to device. Using average emission factors for each device type, the difference in emissions can be estimated on a per-controller basis. We estimated this difference between a low bleed and a high bleed device to be an 84 percent reduction for controllers in the production segment and a 92 percent reduction in emissions in the transmission and storage segment, equating to a difference of 2.1 tpy methane and 0.6 tpy VOC per controller in the production segment and 2.9 tpy methane and 0.08 tpy VOC per controller in the transmission and storage segment. The cost of a new low bleed natural gas-driven pneumatic controller is approximately $255 higher than the cost of a new high bleed device. On an annualized basis, assuming a 15-year equipment lifetime and a 7 percent interest rate, the cost is $28 per year per low bleed controller. Under the single pollutant approach where all the costs are assigned to the reduction of one pollutant, the estimated cost effectiveness is $13 per ton of methane avoided and $48 per ton of VOC avoided per controller in the production segment. Using the multipollutant approach where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the estimated cost effectiveness is $7 per ton of methane avoided and $24 per ton of VOC avoided. When considering the cost of saving the natural gas that would otherwise be emitted for the production segment, the cost effectiveness shows an overall savings under both the single pollutant and multipollutant approaches. For the natural gas transmission and storage segment, the cost effectiveness is $10 per ton methane avoided and $355 per ton VOC avoided per controller using the single pollutant method, and $5 per ton of methane and $178 per ton of VOC avoided per controller using the multipollutant method. Transmission and storage facilities do not own the natural gas; therefore, revenues from reducing the amount of natural gas emitted/lost was not applied for this segment. These values are well within the range of what the EPA considers to be reasonable for methane and VOC using both the single pollutant and multipollutant approaches.

We also evaluated a requirement that natural gas-driven intermittent vent pneumatic controllers only discharge natural gas during actuations. This emissions reduction option would be required in conjunction with a requirement to use low bleed controllers in place of high bleed controllers. The average emission factor determined by an industry study for natural gas-driven intermittent vent controllers, including both properly and improperly operating controllers, is 9.2 scfh natural gas.[255] Comparing this to the emission factor for a properly operating intermittent vent controller of 0.3 scfh natural gas illustrates the significant potential for reductions from a program that

[255] API Field Measurement Study: ''Pneumatic Controllers EPA Stakeholder Workshop on Oil and Gas.'' November 7, 2019—Pittsburgh PA. Paul Tupper.

identifies intermittent vent controllers that are improperly operating and repairing, replacing, or altering their operating conditions so they may function properly. To ensure these devices are emitting natural gas only during actuations in accordance with their design, there would be no equipment expenditure or associated capital costs; however, emissions monitoring or inspections, combined with repair as needed, would be necessary to ensure this proper operation is achieved. We considered requiring independent inspections specifically for intermittent vent controllers but concluded that it would be more efficient to couple inspections of these controllers with the inspections of equipment for leaks under the fugitive monitoring program (see section XII.A of this preamble).

The second option we evaluated was a zero methane and VOC emissions standard. While applicability of both the 2012 NSPS OOOO and the 2016 NSPS OOOOa are based on an individual pneumatic controller (as is the proposed definition of affected facility under NSPS OOOOb), zero-emissions controller options are more appropriately evaluated as ''site-wide'' controls. While individual natural gas-driven pneumatic controllers can be switched to other types of natural-gas driven pneumatic controllers (*e.g.,* high bleed to low bleed types or low bleed to self-contained), the implementation of some zero-emissions controllers options would require equipment that would presumably be used for all the controllers at the site. For example, in order to utilize instrument air driven controllers, a compressor and related equipment would need to be installed. For the vast majority of situations, the EPA does not believe that an owner and operator would install a compressor just for a single controller, but rather would instead install a site-wide system to provide compressed air to all the controllers at the site. Therefore, to adequately account for the costs of the system, including the controllers and the common equipment, we evaluated these zero-emissions controller options using ''model'' plants.

These model plants include assumptions regarding the number of each type of pneumatic controller at a site. Emissions were estimated for each of the model plants using a calculation based on of the number of controllers at the plant and emission factors for each controller. Three sizes of model plants (*i.e.,* small, medium, and large) were developed and used for both the production and transmission and storage segments. Each model plant contained one high bleed natural gas-driven controller and increasing numbers of low bleed and intermittent natural gas-driven controllers. For the production segment, the controller-specific emission factors used are from a recent study conducted by the American Petroleum Institute,[256] and are 2.6 scfh, 16.4 scfh, and 9.2 scfh total natural gas emissions for low bleed, high bleed, and intermittent bleed controllers, respectively. This API study did not cover the transmission and storage segment; therefore, the emission factors from GHGRP subpart W were used, which are 1.37 scfh, 18.2 scfh, and 2.35 scfh for low bleed, high bleed, and intermittent bleed controllers, respectively. It was assumed that the portion of natural gas that is methane is 82.9 percent in the production segment and 92.8 percent in the transmission and storage segment. Further, it was assumed that VOCs were present in natural gas at a certain level compared to methane. The specific ratios assumed were 0.278 pounds VOC per pound methane in the production segment and 0.0277 pounds VOC per pound methane in the transmission and storage segment. This information results in estimated emissions for a single natural gas-driven pneumatic controller in the production segment of 0.39, 2.48, and 1.39 tpy methane and 0.1, 0.7, and 0.4 tpy VOC per low bleed, high bleed, and intermittent vent controller, respectively. The emissions for a single natural gas-driven pneumatic controller in the transmission and storage segment are 0.23, 3.08, and 0.40 tpy methane and 0.006, 0.08, and 0.01 tpy VOC per low bleed, high bleed, and intermittent vent controller, respectively.

Based on the factors described above and the number of each type of controller in each model plant, baseline emissions for the model plants were calculated. For the production model plants, the baseline emissions were calculated to be 5.7 tpy methane and 1.6 tpy VOC for the small model plant (assumes fewer controllers on site than medium plant), 11.2 tpy methane and 3.1 tpy VOC for the medium model plant (assumes more controllers on site than small plant), and 24.9 tpy methane and 6.9 tpy VOC for the large model plant (assumes more controllers on site than the medium plant). For the transmission and storage model plants, the baseline emissions were calculated to be 4.1 tpy methane and 0.1 tpy VOC for the small model plant, 5.7 tpy methane and 0.2 tpy VOC for the medium model plant, and 10.0 tpy methane and 0.3 tpy VOC for the large model plant. For detailed information on the configuration of these model plants and the calculation of the baseline emissions, see the NSPS OOOOb and EG TSD for this rulemaking, which is available in the docket.

Instrument air controllers and electronic controllers were the two zero emission options evaluated. Both these options require electricity to operate. Instrument air systems use compressed air as the signaling medium for pneumatic controllers and pneumatic actuators, whereas electronic controllers send an electric signal to an electric actuator (rather than sending a pneumatic signal to a pneumatic actuator). As instrument air systems are usually installed at facilities where there is a high concentration of pneumatic control valves, electrical power from the grid, and the presence of an operator that can ensure the system is properly functioning, we evaluated the use of instrument air for the large model plant with more controllers and the use of electronic controllers, which can be powered by solar panels, at the small and medium-sized model plant with less controllers. The emission reduction potential of using these zero-emissions controllers rather than natural-gas-driven pneumatic controllers is 100 percent since these systems eliminate all natural gas emissions (they do not emit any VOC or methane). Based on the information available to the EPA during development of this proposal, these two zero-emissions options were the only two analyzed. The EPA solicits comment on the other potential zero-emission options for these sites (mechanical-only controllers, self-contained natural gas-driven controllers, and natural gas-driven controllers where the emissions are captured and routed to a process).

For the small and medium-sized model plants, the zero-emissions option evaluated was the use of electronic controllers. The respective emissions reduction for small and medium-sized plants would be 5.7 and 11.2 tpy methane and 1.6 and 3.1 tpy VOC in the production segment and 4.1 and 5.7 tpy methane and 0.11 and 0.16 tpy VOC in the transmission and storage segment. The cost of a new electronic controller system using electricity from the grid or other on-site power generation is estimated to be $26,000 and $46,000, for small and medium-sized plants respectively. The cost of a new solar-powered electronic controller system is

[256] API Field Measurement Study: ''*Pneumatic Controllers EPA Stakeholder Workshop on Oil and Gas.*'' November 7, 2019—Pittsburgh PA. Paul Tupper.

estimated to be $28,000 and $52,000, for small and medium-sized plants respectively. The estimated annualized capital costs, assuming a 15-year equipment lifetime and a 7 percent interest rate, are $2,800 and $5,040, respectively for a system powered with electricity from the grid or other power source for small and medium-sized plants, and $3,090 and $5,630, respectively, for a solar-powered system for small and medium-sized plants.

For the production segment, considering the slightly more expensive solar-powered system, under the single pollutant approach, the estimated cost effectiveness is $550 per ton of methane avoided and $1,970 per ton of VOC avoided for a small plant and $500 per ton of methane avoided and $1,810 per ton of VOC avoided for a medium-sized plant. Using the multipollutant approach where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the estimated cost effectiveness is $275 per ton of methane avoided and $980 per ton of VOC avoided for a small plant and $250 per ton of methane avoided and $900 per ton of VOC avoided for a medium-sized plant in the production segment. When considering the cost of saving the natural gas that would otherwise be emitted for the production segment, the cost effectiveness is $370 per ton of methane avoided and $1,320 per ton of VOC avoided for a small plant and $320 per ton of methane avoided and $1,150 per ton of VOC avoided for a medium-sized plant. Using the multipollutant approach, the estimated cost effectiveness is $185 per ton of methane avoided and $660 per ton of VOC avoided for a small plant and $160 per ton of methane avoided and $580 per ton of VOC avoided for a medium-sized plant in the production segment. These values are well within the range of what the EPA considers to be reasonable for methane and VOC using both the single pollutant and multipollutant approaches.

For the natural gas transmission and storage segment, considering the slightly more expensive solar-powered system, the estimated cost effectiveness is $750 per ton of methane avoided and $27,200 per ton of VOC avoided for a small plant and $990 per ton of methane avoided and $35,700 per ton of VOC avoided for a medium-sized plant. Using the multipollutant approach, the estimated cost effectiveness is $380 per ton of methane avoided and $13,600 per ton of VOC avoided for a small plant and $490 per ton of methane avoided and $17,800 per ton of VOC avoided for a medium-sized plant. Transmission and storage facilities do not own the natural gas; therefore, revenues from reducing the amount of natural gas emitted/lost was not applied for this segment. While the cost effectiveness values for VOC are higher than the range of what the EPA considers to be reasonable for VOC, the cost effectiveness for methane is within the range of what the EPA considers to be reasonable for methane using the single pollutant approach.

For the large model plants, the zero-emissions option evaluated was the use of instrument air systems. For the production segment, the emissions avoided would be 24.9 tpy methane and 6.9 tpy VOC, and in the transmission and storage segment 10.0 tpy methane and 0.3 tpy VOC. The cost of a new instrument air system is estimated to be $96,000 and the estimated annualized capital costs, assuming a 15-year equipment lifetime and a 7 percent interest rate, are $10,500. For the production segment, under the single pollutant approach, the estimated cost effectiveness is $420 per ton of methane avoided and $1,520 per ton of VOC avoided. Using the multipollutant approach, the estimated cost effectiveness is $210 per ton of methane avoided and $760 per ton of VOC avoided. When considering the cost of saving the natural gas that would otherwise be emitted for the production segment, the cost effectiveness is $240 per ton of methane avoided and $860 per ton of VOC avoided. Using the multipollutant approach, the estimated cost effectiveness is $120 per ton of methane avoided and $430 per ton of VOC avoided in the production segment. These values are well within the range of what the EPA considers to be reasonable for methane and VOC using both the single pollutant and multipollutant approaches.

For the natural gas transmission and storage segment, the estimated cost effectiveness is $1,050 per ton of methane avoided and $38,000 per ton of VOC avoided. Using the multipollutant approach, the estimated cost effectiveness is $530 per ton of methane avoided and $19,000 per ton of VOC avoided. Transmission and storage facilities do not own the natural gas; therefore, revenues from reducing the amount of natural gas emitted/lost was not applied for this segment. While the cost effectiveness values for VOC are higher than the range of what the EPA considers to be reasonable for VOC, the cost effectiveness for methane is within the range of what the EPA considers to be reasonable for methane using the single pollutant approach.

Note that the annual costs for these zero-emissions controllers are based on the annualized capital costs only. While we assume the maintenance costs for electric controllers is less than the costs for natural gas-driven controllers, there are costs associated with the use of electricity that are not incurred for natural gas-driven controllers. We solicit comments on whether such operational costs should be included in these estimates, as well as information regarding these costs.

The capital costs of solar-powered controllers include the cost of the batteries, which represents around 7 percent of the total cost of a solar-powered system. As noted above, the capital cost was annualized assuming a 15-year lifetime, however batteries for a solar system may have a shorter life. We are soliciting comment on the life of these batteries and, if this life is shorter than 15 years, how the costs of these batteries should be included as a maintenance cost for solar powered systems.

The EPA finds that the cost effectiveness for both the low bleed and zero-emissions options are reasonable for sites in the production and natural gas transmission and storage segments. The incremental cost effectiveness in going from the low bleed option to the zero-emissions option is estimated to be $390 and $340 per ton of additional methane eliminated for small and medium-sized plants ($1,400 and $1,200 per ton of VOC), respectively, in the production segment and $640 and $870 per ton of additional methane eliminated for small and medium-sized plants ($23,000 and $31,500 per ton of VOC), respectively, in the transmission and storage segment. The incremental cost effectiveness in going from the low bleed option to the non-emissions option is estimated to be $260 and $940 per ton of additional methane and VOC avoided, respectively, for large plants in the production segment and to be $940 and $34,000 per ton of additional methane and VOC avoided, respectively, for large plants in the transmission and storage segment. These incremental costs of control do not consider savings for the production segment. The EPA believes the incremental costs of control are reasonable for methane and VOC in the production segment, and for methane in the transmission and storage segment.

As discussed above, several States and Canadian provinces require the use of controllers that do not emit methane or VOC throughout the Oil and Natural Gas Industry, which further demonstrates the reasonableness of this option and that there are no technical barriers inhibiting the use of electronic controllers or instrument air systems at sites in the production and transmission and storage segments. In 2015, the EPA concluded that, ''[a]t sites without available electrical service sufficient to power an instrument air compressor, only gas driven pneumatic devices are technically feasible in all situations.'' (80 FR 56623, September 18, 2015). However, since that time, at least two States and two Canadian provinces have adopted regulations that require zero emitting controllers at all new sites. The EPA evaluated these rules, and considers these rules, along with the basic understanding that sources in these areas are able to comply with the rules, evidence that the feasibility issues that led to the EPA's previous decision not to require zero emission controllers in 2015 have been overcome. Further, the EPA recognizes that industry commenters on the proposed Colorado rule raised some of the same technical feasibility issues that have been presented to the EPA in the past, including battery storage capacity issues, weather-related issues, and mechanical issues related to vibration.[257] However, despite these issues being raised, Colorado finalized the requirement that new controllers have a natural gas bleed rate of zero at all sites, even though without power. The EPA has considered new information since 2016 and has now concluded that use of zero-emission controllers is technically feasible subject to a particular proposed exception discussed below. The EPA specifically requests comments on this conclusion. The EPA further solicits comment on market availability of zero-emission options.

Secondary impacts from the use of electronic controllers and instrument air systems are indirect, variable, and dependent on the electrical supply used to power the compressor or controllers. These impacts are expected to be minimal. For example, it is estimated that the electricity needed to operate a compressor is only around 0.4 kW/hour/controller when the compressor is operating. No other secondary impacts are expected. The EPA solicits comment on whether owners and operators would use diesel generators to generate power to run zero-emissions controllers. The EPA recognizes that diesel generators would generate formaldehyde emissions and there could be associated secondary impacts. The EPA does not intend for diesel generators to be used.

[257] Pneumatic Controller Task Force Report to the Air Quality Control Commission. Pneumatic Controller Field Study and Recommendations. Colorado Department of Public Health and Environment. Air Pollution Control Division. June 1, 2020.

In light of the above, we find that the BSER for reducing methane and VOC emissions from natural gas-driven pneumatic controllers at production and transmission and storage sites is the use of zero-emissions controllers. Therefore, for NSPS OOOOb, we are proposing to require zero emissions of methane and VOC to the atmosphere for all pneumatic controllers at production and transmission and storage sites.

Both NSPS OOOO and NSPS OOOOa allow the use of high-bleed pneumatic controllers at production sites and natural gas-driven continuous bleed controllers at natural gas processing plants if it is determined that the use of such a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required ''based on functional needs, including but not limited to response time, safety and positive actuation.'' See 40 CFR 60.5390(a) and 60.5390a(a). This exemption was based on comments received on the 2011 proposed NSPS OOOO rule. There, ''[t]he commenters suggest exemptions that address situations such as those where the natural gas includes impurities that could increase the likelihood of fouling a low-bleed pneumatic controller, such as paraffin or salts; where weather conditions could degrade pneumatic controller performance; during emergency conditions; where flow is not sufficient for low-bleed pneumatic controllers; where electricity is not available; and where engineering judgment recommends their use to maintain safety, reliability or efficiency.'' (77 FR 49520, August 16, 2012). These reasons to allow for an exemption based on functional need were based on the inability of a low-bleed controller to meet the functional requirements of an owner/operator such that a high-bleed controller would be required in certain instances. Since we are now proposing that nearly all pneumatic controllers have a methane and VOC emission rate of zero, subject to exemption explained below, we do not believe that the reasons cited above are still applicable. Therefore, the proposed rule does not include an exemption based on functional need. The EPA is requesting comment regarding the possibility of situations where functional requirements/needs dictate that a natural gas-driven controller that emits any amount of VOC and/or methane be used. For example, are there situations where a zero-emission controller cannot be used due to functional needs such that an owner/operator must use a low-bleed controller or an intermittent controller instead? Comments requesting such an exemption should include details of the specific functional need and why all zero-emission controller options are not suitable.

For many sites, the EPA believes that the most feasible zero-emission option will be solar-powered controllers. The EPA recognizes that solar-powered controllers are dependent on sunshine, and in areas at higher latitudes that undergo prolonged periods without sunshine, this option could be problematic to implement due to the technical limitations of solar panels coupled with the practical realities related to the hours of sunshine received. Therefore, the proposed rule includes an exemption from the zero-emission requirement for pneumatic controllers at sites in Alaska that do not have access to power (*i.e.,* electricity from the grid or produced using natural gas on-site). Sites with power have clearly demonstrated that zero emissions from controllers is achievable, and therefore the EPA is not proposing to exempt pneumatic controllers at sites in Alaska that have power. The proposed exemption would only apply to pneumatic controllers at sites located in Alaska that do not have access to power. In those situations, affected facilities would not be required to comply with the zero-emission standard, but instead must use low-bleed pneumatic controllers (unless a high bleed device is needed for functional reasons) and must monitor any intermittent controllers in conjunction with the fugitives monitoring program to ensure they are not venting when idle. The EPA is soliciting comment on this proposed exemption. Specifically, the EPA is interested in comments regarding the technical feasibility of solar panels to power pneumatic controllers in Alaska. The EPA is also interested in comments regarding whether there are other locations outside of Alaska where such an exemption may be warranted. In submitting responses to this request, commenters should be mindful that two Canadian Provinces, which are north of any U.S. State other than Alaska, require zero-emitting controllers at all new sites.

Natural Gas Processing Plants

Natural gas processing plants typically have higher numbers of pneumatic controllers than production and transmission and storage sites. Model plants were also used for this analysis, specifically the model plants used are the same as those used for the 2011 and 2015 BSER analyses, and include small, medium, and large sites.

The number of controllers is 15, 63, and 175 for small, medium, and large model plants, respectively. All controllers at these sites are assumed to be continuous, but the number of low bleed and high bleed devices is not specified for the model plants. It was assumed that each controller emitted 1 tpy methane, as derived from Volume 12 of a 1996 GRI report.[258] In addition, it was assumed that the portion of natural gas that is methane is 82.8 percent in the natural gas processing segment, and the specific VOC to methane ratio assumed was 0.278 pounds VOC per pound methane. For detailed information on the configuration of these model plants, see the NSPS OOOOb and EG TSD, which is available in the docket.

For natural gas processing plants, the only option evaluated was the requirement to use zero-emission controllers. For our analysis, we examined the use of instrument air, which is the most commonly used controller technology at natural gas processing plants. For this analysis, we used cost data from the 2011 NSPS OOOO TSD updated to 2019 dollars. The updated capital costs for an instrument air system at a natural gas processing plant ranges from $20,000 to $162,000, depending on the system size. The annualized costs were based on a 7 percent interest rate and a 10-year equipment life. This equated to an annualized cost of approximately $13,000 to $96,000 per system. The emissions reduction associated with the installation of an instrument air system over natural gas-driven pneumatic controllers ranged from approximately 15 to 175 tpy methane and 4.2 to 49 tpy VOC per system. The cost effectiveness is estimated to range from approximately $550 to $900 per ton methane eliminated $2,000 to $3,100 per ton VOC eliminated. When considering the costs of saving the natural gas that would otherwise be emitted, the cost effectiveness improves, with a cost effectiveness of $370 to $700 per ton of methane eliminated and $1,300 to $2,500 per ton of VOC eliminated. These cost effectiveness values are presented on a single pollutant basis, and the cost of control on a multipollutant basis is 50 percent of these values. These values are well within the range of what the EPA considers to be reasonable for methane and VOC using both the single pollutant and multipollutant approaches.

The 2012 NSPS OOOO and 2016 NSPS OOOOa require a zero-bleed emission rate for pneumatic controllers at natural gas processing plants. Natural gas processing plants have successfully met this standard for many years now. Further, several State agencies have rules that include this zero-bleed requirement for controllers at natural gas processing plants. This is further demonstration of the reasonableness of a zero methane and VOC emission standard for pneumatic controllers at natural gas processing plants.

We find the cost effectiveness of eliminating methane and VOC emissions using both the single pollutant and multipollutant approaches to be reasonable.

Secondary impacts from the use of instrument air systems are indirect, variable, and dependent on the electrical supply used to power the compressor. These impacts are expected to be minimal, and 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 pneumatic controllers at natural gas processing plants is the use of zero-emissions controllers. Therefore, for NSPS OOOOb, we are proposing to require a natural gas emission rate of zero for all pneumatic controllers at natural gas processing plants. However, we recognize that there may be technical limitations in some situations where zero-emissions controllers may not be feasible, and therefore, we are proposing an allowance for the use of natural gas-driven pneumatic controllers with an emission rate of methane and VOC greater than zero where needed due to functional requirements in this BSER determination. Justification of this functional need must be provided in an annual report and maintained in records.

f. Use of Combustion Devices and VRUs

Another option that could potentially be used to reduce emissions from pneumatic controllers is to collect the emissions from natural gas driven continuous bleed controllers and intermittent vent controllers and route the emissions through a closed vent system to a control device or process. This option is allowed in some State rules. While the EPA did not evaluate the cost effectiveness of this option due to a lack of available information regarding control system costs and feasibility across sites, we think this option could be cost effective for owners and operations in certain situations, particularly if the site already has a control device to which the emissions from controllers could be routed. As this option could be used to achieve significant methane and VOC emission reductions (95 percent or greater), we are soliciting comment on whether this is a control technique used in the industry to reduce emissions from natural gas-driven pneumatic controllers. We are also interested in information related to the performance testing, monitoring, and compliance requirements associated with these control devices. Finally, we are interested in ideas as to how this option could potentially fit with the proposed requirements for pneumatic controllers. For example, if an owner or operator determines that a natural gas-driven pneumatic controller is required for functional need reasons, the EPA could require that emissions be collected and routed to a control device that achieves 95, or 98, percent control.

2. EG OOOOc

The EPA evaluated BSER for the control of methane from existing pneumatic controllers (designated facilities) in all segments in the Crude Oil and Natural Gas source category covered by the proposed NSPS OOOOb and translated the degree of emission limitation achievable through application of the BSER into a proposed presumptive standard for these facilities that essentially mirrors the proposed NSPS OOOOb.

First, based on the same criteria and reasoning as explained above, the EPA is proposing to define the designated facilities in the context of existing pneumatic controllers as those that commenced construction on or before November 15, 2021. Based on information available to the EPA, we did not identify any factors specific to existing sources that would indicate that the EPA should change these definitions as applied to existing sources. As such, for purposes of the emission guidelines, the definition of a designated facility in terms of pneumatic controllers is each individual natural gas driven pneumatic controller (continuous bleed or intermittent vent) that vents to the atmosphere.

Next, the EPA finds that the control options evaluated for new sources for NSPS OOOOb are appropriate for consideration in the context of existing sources under the EG OOOOc. The EPA finds no reason to evaluate different, or additional, control measures in the context of existing sources because the EPA is unaware of any control measures, or systems of emission

[258] Radian International LLC. *Methane Emissions from the Natural Gas Industry,* Vol. 12: Pneumatic Devices. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA–600/R–96–080k. June 1996.

reduction, for pneumatic controllers that could be used for existing sources but not for new sources.

Next, the methane emission reductions expected to be achieved via application of the control measures identified above for new sources are also expected to be achieved by application of the same control measures to existing sources. The EPA finds no reason to believe that these calculations would differ for existing sources as compared to new sources because the EPA believes that the baseline emissions of an uncontrolled source are the same, or very similar, and the efficiency of the control measures are the same, or very similar, compared to the analysis above. This is also true with respect to the costs, non-air environmental impacts, energy impacts, and technical limitations discussed above for the control options identified.

For the most part, the information presented above regarding the costs related to new sources and the NSPS are also applicable for existing sources. The instance where the EPA estimated a difference in the costs between a new and existing source was for the retrofit of an existing production site to use instrument air at sites equipped with electrical power. While the equipment needed is the same as for new sites, it may be more difficult to design and install a retrofitted system. Therefore, the EPA estimates the costs for design and installation to be twice that of the costs for new systems (from approximately $32,000 for new systems to approximately $64,000 for existing systems), resulting in the capital cost of the system being approximately $127,000 with an annualized cost of approximately $14,000.

As noted above, the EPA's analysis for this proposal only examined the cost of instrument air for the large model plant. The total elimination of methane emissions (25 tons per year methane for production sites and 10 tons per year methane for transmission and storage sites) would be the same for existing sources as presented above for new sources. Considering the cost difference, the cost effectiveness for production sites is $560 per ton of methane eliminated without considering savings, and $365 per ton when considering savings. For the transmission and storage segment, the cost effectiveness is $1,400 per ton of methane eliminated. These values are within the range of what the EPA considers to be reasonable for methane. Since none of the other factors are different for existing sources when compared to the information discussed above for new sources, the EPA concludes that BSER for existing sources and the proposed presumptive standard for EG OOOOc to be the requirement to use zero-emission controllers. This proposed EG includes the exemption from the zero-emission standard for pneumatic controllers in Alaska as explained above in the context of the proposed NSPS OOOOb.

b. Possible Phase-In Approach for Existing Sources

The EPA recognizes there could be different compliance time approaches that could be implemented for existing pneumatic controllers. The EPA's proposal for compliance times State plans must include to meet the requirements of the EG can be found in Section XIV.E. As explained there, the EPA is proposing that State plans must generally include a 2-year timeline for compliance in the proposed EG, but is also soliciting comment on the possibility of the EG requiring different compliance timelines for different emission points. Specifically, in the context of pneumatic controllers, the EPA is further soliciting comment on including a phase-in approach in the EG. The EPA recognizes that a phase-in approach may only be appropriate for existing sources as new facilities could presumably plan for zero-emission controllers during construction. A phase-in period could span a number of years (*e.g.,* 2 years), to allow owners and operators to prioritize conversion of natural gas-driven controllers at existing sites based on specific factors (*e.g.,* focus first on sites with onsite power, sites with highest production, sites with the highest number of controllers). A phase-in approach could also result in the conversion of a certain percentage of sites within a given area (*e.g.,* State or basin). For example, the State of Colorado requires a minimum of 40 percent of sites to be converted after 2 years, with 15 percent in year 1 and 25 percent in year 2. The EPA also recognizes potential challenges with a phase-in approach, such as difficulties with enforcement and calculation of the percentage converted due to the frequency at which sites may change ownership. The EPA solicits comment on all aspects of the EG requiring State plans to include a phase-in approach, and whether the agency should consider this type of approach rather than a single compliance time. The EPA also solicits comment on cost and feasibility factors that would enter into adopting and designing a phase-in timeline.

c. Natural Gas Processing Plants

The information presented above regarding the emissions, emission reduction options and their effectiveness, costs, and other factors related to new natural gas processing plants and the NSPS are also applicable for existing sources. Therefore, the EPA concludes that BSER for existing sources and the EG OOOOc for natural gas processing plants is the requirement to use zero-emission controllers.

D. Proposed Standards for Well Liquids Unloading Operations

1. NSPS OOOOb

a. Background

In the 2015 NSPS OOOOa proposal (80 FR 56614–56615, September 18, 2015), the EPA stated that based on available information and input received from stakeholders on the 2014 *Oil and Natural Gas Sector Liquids Unloading Processes* review document,[259] sufficient information was not available to propose a standard for liquids unloading.

At that time, the EPA requested comment on technologies and techniques that could be applied to new gas wells to reduce emissions from liquids unloading events in the future. In the 2016 NSPS OOOOa final rule (81 FR 35846, June 3, 2016), the EPA stated that, although the EPA received valuable information from the public comment process, the information was not sufficient to finalize a national standard representing BSER for liquids unloading at that time.

For this proposal, the EPA conducted a review of available information, including new information that became available after the 2016 NSPS OOOOa rulemaking. As a result of this review, the EPA is proposing a zero VOC and methane emission standard under NSPS OOOOb for liquid unloading, which can be achieved using non-venting liquids unloading methods. In the event that it is technically infeasible or not safe to perform liquids unloading with zero emissions, the EPA is proposing to require that an owner or operator establish and follow BMPs to minimize methane and VOC emissions during liquids unloading events to the extent possible. These proposed requirements apply to each well liquids unloading event.

An overall description of liquids unloading, the definition of a modification, the definition of affected facility, our BSER analysis, and the proposed format of the standard are presented below.

[259] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Liquids Unloading Processes.* Report for Oil and Natural Gas Sector. Liquids Unloading Processes Review Panel. April 2014.

b. Description

In new gas wells, there is generally sufficient reservoir pressure/gas velocity to facilitate the flow of water and hydrocarbon liquids through the well head and to the separator to the surface along with produced gas. In mature gas wells, the accumulation of liquids in the wellbore can occur when the bottom well pressure/gas velocity approaches the average reservoir pressure (*i.e.,* volumetric average fluid pressure within the reservoir across the areal extent of the reservoir boundaries).[260] This accumulation of liquids can impede and sometimes halt gas production. When the accumulation of liquids results in the slowing or cessation of gas production (*i.e.,* liquids loading), removal of fluids (*i.e.,* liquids unloading) is required in order to maintain production. These gas wells therefore often need to remove or ''unload'' the accumulated liquids so that gas production is not inhibited.

The 2019 U.S. GHGI estimates almost 175,800 metric tpy of methane emissions from liquids unloading events for natural gas systems. Specifically, this includes almost 175,800 metric tpy from natural gas production, 98,900 metric tpy of which is from liquids unloading events that use a plunger lift, and 76,900 metric tpy from liquids unloading events that do not use a plunger lift. The overall total represents 3 percent of the total methane emissions estimated from natural gas systems.

In addition to the GHGI information, we also examined the information submitted under GHGRP subpart W. Specifically, we examined the GHGRP subpart W liquids unloading emissions data reported for Reporting Years 2015 to 2019. The liquids unloading emissions reported under GHGRP subpart W include emissions from venting wells, including those wells that vent during events that use a plunger lift and wells that vent during events that do not use a plunger lift. The information reported shows that methane emissions from liquids unloading for a well range from 0 to over 1,000 metric tons (1,100 tons) per year. While the single well with liquids unloading emissions of 1,100 tpy appears to be an outlier, there were over 65 subbasins with reported average liquids unloading emissions of 50 tpy or greater per well when disaggregating data by year and calculation method. There were over 1,000 wells reporting in these subbasins. In addition, there were almost 300 sub-basins with reported average liquids unloading methane emissions of 10 tpy or greater per well. There were almost 8,000 wells reporting in these subbasins.

Another source of information reviewed related to emissions information from liquids unloading was a study published in 2015 by Allen, et al. (University of Texas (UT) Study).[261] [262] The UT Study collected monitoring data across regions of the U.S. Among other findings in this report, for wells that vent more than 100 times per year, the average methane emissions per well per year were 27 metric tpy, with 95 percent confidence bounds of 10 to 50 Mg/yr (based on the confidence bounds in the emissions per event). The monitoring data shows that methane emissions from liquids unloading for a well range from 1 to 19,500 Mscf per year, or 0.02 to 406 tpy.[263] As indicated by the UT study [264] emissions information, a small fraction of wells account for a large fraction of liquids unloading emissions.

c. Modification

As noted in section XII.D.1.b, new wells typically do not require liquids unloading until the point that the accumulation of liquids impedes or even stops gas production. At that point, the well must be unloaded of liquids to improve the gas flow. One method to accomplish this involves the intentional manual venting of the well to the atmosphere to improve gas flow. This is done using various techniques. One common manual unloading technique diverts the well's flow, bypassing the production separator to a lower pressure source, such as an atmospheric pressure tank. Under this scenario, venting to the atmospheric tank occurs because the separator operates at a higher pressure than the atmospheric tank and the well will temporarily flow to the atmospheric tank (which has a lower pressure than the pressurized separator). Natural gas is released through the tank vent to the atmosphere until liquids are unloaded and the flow diverted back to the separator. As discussed later in this section, the EPA has received feedback that there are technical difficulties with flaring vented emissions as a result of the intermittent and surging flow characteristic of venting for liquids unloading, and the changing velocities during an unloading event.

Since each unloading event constitutes a physical or operational change to the well that has the potential to increase emissions, the EPA is proposing to determine each event of liquids unloading constitutes a modification that makes a well an affected facility subject to the NSPS. See 40 CFR 60.14(a) (''any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act''). The EPA solicits comment on this determination.

d. Definition of Affected Facility

Given that we have proposed to determine that every liquids unloading event is a modification, the next step is to define the affected facility. The EPA recognizes that methods are commonly employed that significantly reduce, or even eliminate, emissions from liquids unloading. Therefore, the EPA is co-proposing two options on how a modified well due to a liquids unloading event would be covered under the rule.

Under the first option, the affected facility subject to the requirements of NSPS OOOOb would be defined as every well that undergoes liquids unloading after the effective date of the final rule. Under this scenario, a well that undergoes liquids unloading is an affected facility regardless of whether the liquids unloading approach used results in venting to the atmosphere. This option posits that techniques employed to unload liquids that do not increase emissions are not to be considered in whether the unloading event is an affected facility or not, since the liquids unloading event in their absence could result in an emissions increase. This is somewhat analogous to a physical change to an existing storage vessel that resulted in the ability to increase throughput, and thus emissions. This physical change could result in an increase in emissions even if emissions were captured and routed back to a process such that the level of pollutant actually emitted to the atmosphere did not change. Under this scenario, the EPA could request and obtain compliance and enforcement information on non-venting liquids

[260] Gordon Smith Review. *Oil & Natural Gas Sector Liquids Unloading Processes.* Submitted: June 16, 2014. Pg. 4.

[261] D.T. Allen, D.W. Sullivan, D. Zavala-Araiza, A.P. Pacsi, M. Harrison, K. Keen, M.P. Fraser, A. Daniel Hill, B.K. Lamb, R.F. Sawyer, J.H. Seinfeld, *Methane emissions from process equipment at natural gas production sites in the United States: Liquid unloadings.* Environ. Sci. Technol. 49, 641–648 (2015). doi:10.1021/es504016r Medline. (UT Study).

[262] D.T. Allen, D.W. Sullivan, D. Zavala-Araiza, A.P. Pacsi, M. Harrison, K. Keen, M.P. Fraser, A. Daniel Hill, B.K. Lamb, R.F. Sawyer, J.H. Seinfeld. *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings—Supporting Information;* (UT Study—SI). Table S5–1, pg. 21.

[263] UT Study—SI. Tables S3–1 to S3–3, pgs. 11–14.

[264] UT Study. pg. 642.

unloading event methods commonly employed (simple records and reporting requirements), as well as venting liquids unloading events.

Under the second option, the affected facility would be defined as every well that undergoes liquids unloading using a method that is not designed to totally eliminate venting (*i.e.,* that results in emissions to the atmosphere). Under this scenario, if an owner or operator employs a method to unload liquids that does not vent to the atmosphere, the liquids unloading event would not constitute an increase in emissions and therefore, the well would not be an affected facility. As such, the first liquids unloading event that vents to the atmosphere after the effective date of the final rule, would be an affected facility subject to the requirements of NSPS OOOOb. This option could create an enforcement information and compliance gap. Specifically, the EPA would not be able to obtain compliance assurance information on liquids unloading events and emissions/methods and there could be a decreased incentive for owners or operators to ensure that no unexpected emission episodes occur when a method designed to be non-venting is used.

The EPA solicits comments on the two affected facility definition options being co-proposed. Specifically, we request comment on whether there are implementation and/or compliance assurance concerns that arise with applying either of the co-proposed options. In addition, we request comment on if there are any appropriate exemptions for operations that may be unlikely to result in emissions, such as wellheads that are not operating under positive pressure.

e. 2021 BSER Analysis

The choice of what liquids unloading technique to employ is based on an operator well-by-well and reservoir-by-reservoir engineering analysis. Because liquids unloading operations entail a number of complex science and engineering considerations that can vary across well sites, there is no single technological solution or technique that is optimal for liquids unloading at all wells. Rather, a large number of differing technologies, techniques and practices (*i.e.,* ''methods'') have been developed to address the unique characteristics of individual wells so as to manage liquids and maintain production. These methods include, but are not limited to, manual unloading, velocity tubing or velocity strings, beam or rod pumps, electric submergence pumps, intermittent unloading, gas lift (*e.g.,* use of a plunger lift), foam agents, wellhead compression, and routing the gas to a sales line or back to a process.

Selecting a particular method to meet a particular well's unloading needs must be based on a production engineering decision that is designed to remove the barriers to production. The situation is further complicated as the best method for a particular well can change over time. At the onset of liquids loading, techniques that rely on the reservoir energy are typically used. Eventually a well's reservoir energy is not sufficient to remove the liquids from the well and it is necessary to add energy to the well to continue production.

In the 2016 NSPS OOOOa final rule preamble, the EPA acknowledged that operators must select the technique to perform liquids unloading operations based on the conditions of the well each time production is impaired. During the development of the 2016 NSPS OOOOa rule, the EPA considered subcategorization based on the potential for well site liquids unloading emissions but determined that the differences in liquids unloading events (with respect to both frequency and emissions level) are due to specific conditions of a given well at the time the operator determines that well production is impaired such that unloading must be done. Since owners and operators must select the technique to perform an unloading operation based on those conditions, and because well conditions change over time, each iteration of unloading may require repeating a single technique or attempting a different technique that may not have been appropriate under prior conditions. As noted above, we recognized that the choice of method to unload liquids from a well needs to be a production engineering decision based on the characteristics of the well at the time of the unloading, and owners and operators need the flexibility to select a method that is effective and can be safely employed. No information has become available since 2016 that leads the EPA to reach a different conclusion regarding subcategorization of wells for the purpose of developing standards to address liquids unloading emissions. Further, the EPA acknowledges the need for owners and operators to have the flexibility to select the most appropriate method(s) and recognize that any standard must not impede this flexibility.

Many methods used for liquids unloading do not result in any venting to the atmosphere, provided that the method is properly executed. High-level summaries of a few of these methods are provided below.[265]

A commonly used method employed in the field is the use of a plunger lift system. While plunger lift systems often are used in a way to minimize emissions, under certain conditions they can be operated to unload liquids in a manner that eliminates the need to vent to the atmosphere. Plunger lifts use the well's own energy (gas/pressure) to drive a piston or plunger that travels the length of the tubing in order to push accumulated liquids in the tubing to the surface. Specific criteria regarding well pressure and liquid to gas ratio can affect applicability. Candidate wells for plunger lift systems generally do not have adequate downhole pressure for the well to flow freely into a gas gathering system. Optimized plunger lift systems (*e.g.,* with smart well automation) can decrease the amount of gas vented by up to and greater than 90 percent, and in some instances can reduce the need for venting due to overloading. Plunger lift costs range from $1,900 to $20,000.[266] Adding smart automation can cost anywhere between an estimated $4,700 to $18,000 depending on the complexity of the well. Natural Gas STAR estimates that the annual cost savings from avoided emissions from the use of an automated system ranges anywhere between $2,400 and $10,241 per year.[267]

Other artificial lifts (*e.g.,* rod pumps, beam lift pumps, pumpjacks and downhole separator pumps) are typically used when there is inadequate pressure to use a plunger lift, and the only means of liquids unloading to keep gas flowing is downhole pump technology. Artificial lifts can be operated in a manner that produces no emissions. The use of an artificial lift requires access to a power source. The capital and installation costs (including location preparation, well clean out, artificial lift equipment and pumping unit) is estimated to be $41,000 to $62,000/well, with the average cost of a pumping unit being between $17,000 to $27,000. [268]

[265] ''Oil and Natural Gas Sector Liquids Unloading Processes''. Report for Oil and Natural Gas Sector Liquids Unloading Processes Review Panel. Prepared by U.S. EPA OAQPS. April 2014.

[265] 80 FR 56593, September 18, 2015.

[266] U.S. Environmental Protection Agency. *Installing Plunger Lift Systems in Gas Wells.* Office of Air and Radiation: Natural Gas Star Program. Washington, DC. 2006.

[267] U.S. Environmental Protection Agency. (U.S. EPA) 2011. *Options for Removing Accumulated Fluid and Improving Flow in Gas Wells.* Office of Air and Radiation: Natural Gas Star Program. Washington, DC. 2011. pg. 1.

[268] U.S. EPA, 2011. pg. 9.

Velocity tubing is smaller diameter production tubing that reduces the cross-sectional area of flow, increasing the flow velocity and achieving liquids removal without blowing emissions to the atmosphere. Generally, a gas flow velocity of 1,000 feet per minute (fpm) is necessary to remove wellbore liquids. Velocity tubing strings are appropriate for low volume natural gas wells upon initial completion or near the end of their productive lives with relatively small liquids production and higher reservoir pressure. Candidate wells include marginal gas wells producing less than 60 Mcfd. Similarly, coil tubing can also be used in wells with lower velocity gas production (*i.e.,* seamed coiled tubing may provide better lift due to elimination of turbulence in the flow stream). The proper use of velocity tubing is considered to be a ''no emissions'' solution. It is also low maintenance and effective for low volumes lifted. Velocity lifting can be deployed in combination with foaming agents (discussed below). The capital and installation costs are estimated to range anywhere from $7,000 to $64,000 per well.[269] Installation requires a well workover rig to remove existing production tubing and placement of the smaller diameter tubing string in the well.

The use of foaming agents (soap, surfactants) as a method to unload liquids is implemented by the injection of foaming agents in the casing/tubing annulus by a chemical pump on a timer basis. The gas bubbling of the soap-water solution creates gas-water foam which is more easily lifted to the surface for water removal. This, like the use of artificial lifts, requires power to run the surface injection pump. Additionally, foaming agents work best if the fluid in the well is at least 50 percent water and are not effective for natural gas liquids or liquid hydrocarbons. This method requires that the soap supply be monitored. If the well is still unable to unload fluid, smaller tubing may be needed to help lift the fluids. Foaming agents and velocity tubing are reported as possibly being more effective when used in combination. No equipment is required in shallow wells. In deep wells, a surfactant injection system requires the installation of surface equipment and regular monitoring. Foaming agents are reported as being low cost ''no emissions'' solution. The capital and startup costs to install soap launchers and velocity tubing is estimated to range between $7,500 and $67,880, with the monthly cost of the foaming agent is approximately $500 per well or approximately $6,000 per year.[270]

[269] U.S. EPA, 2011. pg. 8.

These are just a few examples of demonstrated methods that are being used in the industry to unload accumulated liquids that impair production, that can be implemented without venting and, thus, without emissions. As stressed earlier, the selection of a specific method must be made based on well-specific characteristics and conditions.

Since GHGRP subpart W only requires reporting of liquids unloading events that resulted in venting of methane, no information is submitted regarding those wells that utilize a non-venting method. The EPA is also not aware of information that specifies the total number of wells that need to undergo liquids unloading. A 2012 report sponsored by the API and American Natural Gas Alliance (ANGA)[271] provided more definitive insight into the number of wells that use non-venting liquids unloading methods. This report indicated that an estimated 21.1 percent of plunger equipped wells vent, and 9.3 percent of non-plunger equipped wells vent. The EPA interprets this to mean that almost 80 percent of plunger-equipped wells, and over 90 percent of non-plunger-equipped wells perform liquids unloading and utilize non-venting methods.

As noted above, there is a tremendous range in the emissions from liquids unloading reported for individual wells. Further, as discussed above, the costs for the non-venting methods range considerably. Also, as discussed above, we have determined that the myriad of possible reservoir conditions and unloading methods do not lend to any reasonable subcategorization of the industry for which representative wells could be designed. Therefore, it is not possible to develop a ''model'' well, or even a series of model wells, that can be used to conduct the type of analysis frequently performed for BSER determinations that calculates a cost per ton of emissions reduced (or in this case eliminated).

Based on the highest costs included in the cost examples provided above, the cost effectiveness of a non-venting method would be considered reasonable for wells with annual methane emissions from liquids unloading of 16 tpy or greater, or VOC emissions of 3 tpy or greater. This upper range is based on the cost of the combination of velocity tubing and soap launchers. The upper range of the capital cost cited above was $67,800. Annualizing this capital cost at a 7 percent interest rate over 10 years, and adding in the $6,000 per year foaming agent cost, results in a total annual cost of $15,600. Given the total elimination of emissions, the cost effectiveness for a well with 16 tpy methane emissions would be $980 per ton of methane reduced, which is a level that the EPA considers reasonable for methane. Similarly, for VOC, the cost effectiveness for a well with 3 tpy VOC emissions would be $5,200 per ton of VOC reduced. This is also a level that the EPA considers reasonable. Given the range of costs, it could be reasonable even for some wells with annual liquids unloading methane emissions as low as 2.5 tpy ($400 per ton of methane reduced (velocity tubing)), or VOC emissions as low as 0.2 tpy ($5,000 per ton of VOC reduced (velocity tubing)). Based on the GHGRP subpart W data for the years 2015 through 2019, around 50 percent of the wells that performed liquids unloading and reported emissions reported emissions higher than these levels.

[270] U.S. EPA. 2011. Pg. 8.

[271] Shires, T. URS Corporation and Lev-On, M. the LEVON Group. *Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production.* Summary and Analysis of API and ANGA Survey Responses. Prepared for the American Petroleum Institute and the American Natural Gas Alliance. September 21, 2012.

While owners and operators must select a liquids unloading method that is applicable for the well-specific conditions, they have the choice of many methods that can be used to eliminate venting/emissions from liquids unloading events. While we do not have information to calculate the specific percentage of total wells undergoing liquids unloading that use non-venting methods, available information suggests that a majority of wells that undergo liquids unloading do not vent. The EPA solicits information on the number (or percent) of liquids unloading events that vent to the atmosphere versus do not vent to the atmosphere under normal conditions and whether there are technical obstacles (other than costs) that would not allow liquids unloading to be performed without venting.

CAA section 111(a) requires that the standard reflect the BSER that the EPA determines ''has been adequately demonstrated.'' An ''adequately demonstrated system'' is one that ''has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'' *Essex Chem.,* 486 F.2d at 433. For the reasons explained above and further elaborated below, the EPA considers non-venting methods such as those described above to have been adequately demonstrated as the BSER for liquids unloading events. The complete elimination of emissions from liquids unloading with these non-venting methods have been adequately demonstrated in practice. The EPA notes that as part of decisions regarding liquids unloading, one goal of owners and operators is to eliminate venting to prevent the loss of product (natural gas) that could be routed to the sales line. States currently encourage the use of methods to eliminate emissions unless venting of emissions is necessary for safety reasons or when it is technically infeasible to not vent to unload liquids from the wellbore. For example, Pennsylvania has a general plan approval and/or general operating permit application (BAQ–GPA/GP–5A) that specifies that an owner or operator that conducts wellbore liquids unloading operations shall use best management practices including, but not limited to, plunger lift systems, soaping, swabbing, unless venting is necessary for safety to mitigate emissions during liquids unloading activities (Best Available Technology (BAT) Compliance Requirements under Section L of the General Permit).

As discussed previously, a majority of wells already conduct liquids unloading operations without venting to the atmosphere. Also, as discussed previously, there are multiple non-venting liquids unloading methods that an owner and operator can select based on a well's specific characteristics and conditions. Our evaluation of costs shows that there are non-venting liquids unloading methods that could be employed to unload liquids that are reasonable given a wide range of emission levels. Finally, there are no negative secondary environmental impacts that would result from the implementation of methods that would eliminate venting of methane and VOC emissions to the atmosphere. In light of the above, the EPA considers non-venting liquids unloading methods to have been adequately demonstrated to represent BSER for reducing methane and VOC emissions during liquids unloading events.

An ''adequately demonstrated'' system needs not be one that can achieve the standard ''at all times and under all circumstances.'' *Essex Chem.,* 486 F.2d at 433. That said, as discussed below, the EPA recognizes that there may be reasons that a non-venting method is infeasible for a particular well, and the proposed rule would allow for the use of BMPs to reduce the emissions to the maximum extent possible.

The EPA recognizes that there may be safety and technical reasons why venting to the atmosphere is necessary to unload liquids. In addition, it is possible that a well production engineer has already explored non-venting options and determined that there was no feasible option due to its specific characteristics and conditions. For scenarios where a liquids unloading method employed requires venting to the atmosphere, the EPA evaluated requiring BMPs that would minimize venting to the maximum extent possible. There are several States that require the development and implementation of BMPs that minimize emissions from liquids unloading events that vent. For example, Colorado requires specified BMPs to eliminate or minimize vented emissions from liquids unloading. The rule requires that all attempts be made to unload liquids without venting unless venting is required for safety reasons. If venting is required, the rule requires that owners and operators be on site and that they ensure that any venting is limited to the maximum extent practicable. Specific BMPs evaluated are based on State rules that require BMPs to minimize emissions during liquids unloading events are to require operators to monitor manual liquids unloading events onsite and to follow procedures that minimize the need to vent emissions during an event. This includes following specific steps that create a differential pressure to minimize the need to vent a well to unload liquids and reducing wellbore pressure as much as possible prior to opening to atmosphere via storage tank, unloading through the separator where feasible, and requiring closure of all well head vents to the atmosphere and return of the well to production as soon as practicable. For example, where a plunger lift is used, the plunger lift can be operated so that the plunger returns to the top and the liquids and gas flow to the separator. Under this scenario, venting of the gas can be minimized and the gas that flows through the separator can be routed to sales. In situations where production engineers select an unloading technique that results or has the potential to vent emissions to the atmosphere, owners and operators already often implement BMPs in order to increase gas sales and reduce emissions and waste during these (often manual) liquids unloading activities. We performed a cost and impacts evaluation of the use of BMPs to reduce emissions from liquids unloading. This evaluation is provided in the NSPS OOOOb and EG TSD for this rulemaking.

Another potential method for reducing emissions from liquids unloading is to capture the vented gas from an unloading event and route it to a control device. At the time the Crude Oil and Natural Gas Sector Liquids Unloading Processes draft review document was submitted to reviewers, the EPA noted that, although the EPA was not aware of any specific instances where combustion devices/flares were used to control emissions vented from unloading events, the EPA requested information on the technical feasibility of flaring as an emissions control option for liquids unloading events. Feedback received from reviewers indicated that there are technical reasons that flaring during liquids unloading is not a feasible option.[272] Reviewers emphasized that, in order to flare gas during liquids unloading, the liquids would need to be separated from the well stream, and the intermittent and surging flow characteristics of venting for liquids unloading, changing velocities during an unloading, and flare ignition considerations for a sporadically used flare (*i.e.,* would require either a continuous pilot or electronic igniter) would make use of a flare technically and financially infeasible.[273] [274] The reviewers indicated that separating the liquids from the well stream would require the well stream to flow through a separator with sufficient backpressure to separate the gas and liquids. One reviewer noted that after separating the liquids from the well stream the gas would then be piped to flare system, where the backpressure needed to operate the separator would affect the performance of a plunger lift system (if used). Based on feedback received on the technical and cost feasibility of using a flare to control vented emissions from liquids unloading events indicating that a flare cannot be used in all situations, we did not consider this option any further in this proposal. However, the EPA is soliciting comments about the use of control devices to reduce emissions from liquids unloading events. Specifically, we request information on the types of wells and unloading events for which routing to control is feasible

[272] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Liquids Unloading Processes.* Report for Crude Oil and Natural Gas Sector. Liquids Unloading Processes Review Panel. April 2014.

[273] Gordon Smith Review. *Oil and Natural Gas Sector Liquids Unloading Processes.* Review Submitted: June 16, 2014. Pg. 31.

[274] Jim Bolander, P.E., Senior Vice President, Southwestern Energy (SWN). Review Submitted: April 2014. Pg. 8.

and effective, the level of emission reduction achieved, and the testing and monitoring requirements that apply.

A similar potential method is to capture the vented gas from an unloading event and route it to the sales line or back to a process. This could potentially represent another method that results in zero emissions. While this is not a mitigation option that has been specifically mentioned for emissions from liquids unloading, it is a common option for other emission sources in the oil and natural gas production segment. The EPA is soliciting comments about the option to collect and route emissions back to the sales line or to a process. Specifically, we request information on the types of wells and unloading events for which this option is feasible (if any). If this option is feasible, we also request information on the specifics of the equipment and processes needed to accomplish this, as well as the costs.

In conclusion, the EPA evaluated several options and identified the use of non-venting methods as the BSER for reducing methane and VOC emissions during liquids unloading events. However, the EPA recognizes there could be situations where it is infeasible to utilize a non-venting method. Therefore, the EPA proposes to allow for the development and implementation of BMPs to reduce emissions to the extent possible during liquids unloading where it is infeasible to utilize a non-venting method.

f. Format of the Standard

As discussed under section XII.D.1.d of this preamble, the EPA is co-proposing two regulatory approaches to implement the BSER determination.

For Option 1, the affected facility would be defined as every well that undergoes liquids unloading. This would mean that wells that utilize a non-venting method for liquids unloading would be affected facilities and subject to certain reporting and recordkeeping requirements. These requirements would include records of the number of unloadings that occur and the method used. 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 the proposed rule Option 1 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.

For wells that utilize methods that vent to the atmosphere, the proposed rule would require that they: (1) Document why it is infeasible to utilize a non-venting method due to technical, safety, or economic reasons; (2) develop BMPs that ensure that emissions during liquids unloading are minimized; (3) follow the BMPs during each liquids unloading event and maintain records demonstrating they were followed; (4) report the number of liquids unloading events in an annual report, as well as the unloading events when the BMP was not followed. While the proposed rule would not dictate the specific practices that must be included, it would specify minimum acceptance criteria required for the types and nature of the practices. Examples of the types and nature of the required practice elements for BMP are provided in section XII.D.1.e, such as those contained in Colorado's rule. The EPA is specifically requesting comment on the minimum elements that should be required in BMPs and the specificity that the proposed rule should include regarding these elements.

An advantage of this regulatory option is that it would provide information to the EPA on the number of liquids unloading events that occur and the types of unloading methods used. Having this important information would enhance the EPA, the industry, and the public's knowledge of emissions from liquids unloading. Option 1 would also provide incentive for owners and operators to ensure that non-venting methods are applied as they are designed such that unexpected emissions do not occur as the result of technology malfunctions or operator error. However, it would result in some recordkeeping and reporting burden for wells that already use or plan to use non-venting methods that would not be incurred under Option 2.

For Option 2, the affected facility would be defined as every well that undergoes liquids unloading using a method that is not designed to eliminate venting. The significant difference in this option is that wells that utilize non-venting methods would not be affected facilities that are subject to the NSPS OOOOb. Therefore, they would not have requirements other than to maintain records to demonstrate that they used non-venting liquids unloading methods. The requirements for wells that use methods that vent would be the same as described above under Option 1.

The EPA believes that this option would provide additional incentive for owners and operators to seek ways to overcome potential infeasibility issues to ensure that their wells are not affected facilities and subject to reporting and recordkeeping requirements. This would ultimately result in lower emissions. However, this would not provide the EPA information to have a more comprehensive understanding of emissions and emission reduction methods from liquids unloading. It would also not provide incentive for owners and operators to ensure that no unexpected emission episodes occur when a method designed to be non-venting is used.

2. EG OOOOc

As described above, the EPA is proposing that each unloading event represents a modification, which will make the well subject to new source standards under NSPS. Therefore, existing wells that undergo liquids unloading would become subject to NSPS OOOOb. This will mean that there will never be a well that undergoes liquids unloading that will be ''existing'' for purposes of CAA section 111(d). Therefore, there is no need for emissions guidelines or an associated presumptive standard under EG OOOOc for liquids unloading operations.

E. Proposed Standards for Reciprocating Compressors

1. NSPS OOOOb

a. Background

The 2012 NSPS OOOO and the 2016 NSPS OOOOa applied to each individual new or reconstructed reciprocating compressor, except for those compressors located at a well site, or those located at an adjacent well site and servicing more than one well site. The 2016 NSPS OOOOa required the reduction of methane and VOC emissions from new, reconstructed, or modified reciprocating compressors by replacing rod packing systems within 26,000 hours or 36 months of operation, regardless of the condition of the rod packing. As an alternative, the 2016 NSPS OOOOa allowed owners or operators to collect the emissions from the rod packing using a rod packing emissions collection system that operates under negative pressure and route the rod packing emissions to a process through a closed vent system.

In determining BSER for reciprocating compressors in 2016, the EPA determined that the previous determination for NSPS OOOO conducted in 2011/2012 still represented BSER in 2016. In the 2012 determination the EPA first concluded that the piston rod packing wear produces fugitive emissions that cannot be captured and conveyed to a control device, and that an operational standard pursuant to section 111(h) of the CAA was appropriate. The EPA conducted analyses of the costs and emission reductions of the replacement of rod packing every 3 years or 26,000 hours of operation and determined that the costs per ton of emissions reduced were reasonable for the industry, with the exception of compressors at well sites. Based on the 2011 BSER analysis, requiring replacement of rod packing every 3 years or 26,000 hours of operation for well site reciprocating compressors was not considered cost effective (almost $57,000 per ton of VOC reduced).[275] No other more stringent control options were evaluated at that time.

For this review of the NSPS, the EPA focused on these control options which were previously assessed for the 2012 NSPS OOOO and the 2016 NSPS OOOOa. In addition, we evaluated an option that would require annual monitoring to determine if the rod packing needed to be replaced. This option is in contrast to the option where replacement is required on a fixed (*e.g.,* 3 year) schedule. For this review, BSER was evaluated for reciprocating compressors at gathering and boosting stations in the production segment (considered to be representative of emissions from reciprocating compressors at centralized production facilities), at natural gas processing plants, and at sites in the transmission and storage segment. In 2012 and in 2016, the EPA determined that the cost effectiveness of replacement of the rod packing based on the fixed 3-year (or 26,000 hours) schedule was unreasonable for reciprocating compressors located at the well site (discussed below). No new information has become available to change this determination. Therefore, we did not include reciprocating compressors located at well sites in our evaluation of regulatory options.

However, as discussed in section XI.L (Centralized Production Facilities) of this preamble, the EPA believes the definition of ''well site'' in NSPS OOOOa may cause confusion regarding whether reciprocating compressors located at centralized production facilities are also exempt from the standards. The EPA is proposing a new definition for a ''centralized production facility''. The EPA is proposing to define centralized production facilities separately from well sites because the number and size of equipment, particularly reciprocating and centrifugal compressors, is larger than standalone well sites which would not be included in the proposed definition of ''centralized production facilities''. This proposal is necessary in the context of reciprocating compressors to distinguish between these compressors at centralized production facilities where the EPA has determined that the standard should apply, and compressors at standalone well sites where the EPA has determined that the standard should not apply. In our current analysis, described below, we consider the reciprocating compressor gathering and boosting segment emission factor as being representative of reciprocating compressor emissions located at centralized production facilities. As such, the EPA is proposing that reciprocating compressors located at centralized production facilities would be subject to the standards in NSPS OOOOb and the EG in subpart OOOOc, but reciprocating compressors at well sites (standalone well sites) would not.

As a result of the EPA's review of NSPS OOOOa, we are proposing that BSER is to replace the rod packing when, based on annual flow rate measurements, there are indications that the rod packing is beginning to wear to the point where there is an increased rate of natural gas escaping around the packing to unacceptable levels. We are proposing that if annual flow rate monitoring indicates a flow rate for any individual cylinder as exceeding 2 scfm, an owner or operator would be required to replace the rod packing.

b. Description

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 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.

As discussed previously, emissions from a reciprocating compressor occur when, over time, during operation of the compressor, the rings that form a seal around the piston rod that prevents gas from escaping become worn. This results in increasing emissions from the compression cylinder. Based on the 2021 GHGI,[276] the methane emissions from reciprocating compressors in 2019 represented 14 percent of the total methane emissions from natural gas systems in the Crude Oil and Natural Gas Industry sector. For segments where the GHGI included a breakdown of methane emissions for reciprocating compressors, the reported emissions were 309,500 metric tons for the gathering and boosting segment, 46,700 metric tons for the processing segment, 406,500 metric tons for the transmission segment, and 103,200 metric tons for the storage segment.

c. Affected Facility

For purposes of the NSPS, the reciprocating compressor affected facility is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under the proposed rule for the NSPS OOOOb. As discussed above, the EPA is proposing that the affected facility includes reciprocating compressors located at centralized production facilities and the affected facility exception for ''a well site, or an adjacent well site servicing more than one well site'' applies to standalone well sites and not centralized production facilities.

d. 2021 BSER Analysis

The methodology used for estimating emissions from reciprocating compressor rod packing is consistent with the methodology developed for the 2012 NSPS OOOO BSER analysis and then also used to support the 2016 NSPS OOOOa BSER. This approach uses volumetric methane emission factors referenced in the EPA/GRI study[277] as the basis, multiplied by the density of methane. These factors were per cylinder, so they were multiplied by the average number of cylinders per reciprocating compressor at each oil and gas industry segment, the pressurized factor (percentage of hours per year the compressor was pressurized), and 8,760 hours (number of hours in a year). Once the methane emissions were calculated, VOC emissions were calculated by multiplying the methane by ratios developed based on representative gas composition. The specific ratios that were used for this analysis were 0.278

[275] 2011 NSPS OOOO TSD. pg. 6–17.

[276] U.S. Environmental Protection Agency. Inventory of U.S. Greenhouse Gas Emissions and Sinks (1990–2019). Published in 2021. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019.

[277] EPA/GRI. (1996). *Methane Emissions from the Natural Gas Industry: Volume 8—Equipment Leaks.*

pounds VOC per pound of methane for the production and processing segments, and 0.0277 pounds VOC per pound of methane for the transmission and storage segment. The resulting baseline emissions from reciprocating compressors were 12.3 tpy methane (3.4 tpy VOC) from gathering and boosting stations, 23.3 tpy methane (6.5 tpy VOC) from natural gas processing plants, 27.1 tpy methane (0.75 tpy VOC) from transmission stations, and 28.2 tpy methane (0.78 tpy VOC) from storage facilities.

Reducing emissions that result from the leaking of natural gas past the piston rod packing can be accomplished through several approaches including: (1) Specifying a frequency for the replacement of the compressor rod packing, (2) monitoring the emissions from the compressor and replacing the rod packing when the results exceed a specified threshold, (3) specifying a frequency for the replacement of the piston rod, (4) requiring the use of specific rod packing materials, and/or (5) capturing the leaking gas and routing it either to a process or a control device.

There was either insufficient information to establish BSER or it was determined that the option cannot be applied in all situations for approach options (3) through (5). These are discussed briefly below.

Like the packing rings, piston rods on reciprocating compressors also deteriorate. Piston rods, however, wear more slowly than packing rings, having a life of about 10 years.[278] Rods wear ''out-of-round'' or taper when poorly aligned, which affects the fit of packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. An out-of-round shaft not only seals poorly, allowing more leakage, but also causes uneven wear on the seals, thereby shortening the life of the piston rod and the packing seal. Replacing or upgrading the rod can reduce reciprocating compressor rod packing emissions. Also, upgrading piston rods by coating them with tungsten carbide or chrome reduces wear over the life of the rod. We assume that operators will choose, at their discretion, when to replace/realign or retrofit the rod as part of regular maintenance procedures and replace the rod when appropriate when the compressor is out of service for other maintenance such as rod packing replacement. Although replacing/realigning or retrofitting the rod has been identified as a potential methane and VOC emission reduction option for reciprocating compressors, there is insufficient information on its emission reduction potential and use throughout the industry. Therefore, we did not evaluate this option any further as BSER for this proposal.

Although specific analyses have not been conducted, there may be potential for reducing methane and VOC emissions by updating rod packing components made from newer materials, which can help improve the life and performance of the rod packing system. One option is to replace the bronze metallic rod packing rings with longer lasting carbon-impregnated Teflon rings. Compressor rods can also be coated with chrome or tungsten carbide to reduce wear and extend the life of the piston rod. Although changing the rod packing material has been identified as a potential methane and VOC emission reduction option for reciprocating compressors, there is insufficient information on its emission reduction potential and use throughout the industry. Therefore, we did not evaluate this option any further as BSER for this proposal.

The 2016 NSPS OOOOa includes the alternative to route the emissions from reciprocating compressors to a process. One estimate obtained by the EPA states that a gas recovery system can result in the elimination of over 99 percent of methane emissions that would otherwise occur from the venting of the emissions from the compressor rod packing. The emissions that would have been vented are combusted in the compressor engine to generate power. It was estimated that, if a facility is able to route rod packing vents to a VRU system, it is possible to recover approximately 95–100 percent of emissions. As a comparison, the EPA estimated that the 3-year/26,000-hour changeout results in between 55 and 80 percent emission reduction. Therefore, an option to achieve additional emission reductions could be to require routing the reciprocating compressor emissions to a process/through a closed vent system under negative pressure. Although this was a control option considered in the 2016 NSPS OOOOa (and included as an alternative), the EPA did not require routing to a process for all compressors because at that time there was insufficient information to require this as a control for all reciprocating compressors. The EPA received feedback that this option cannot be applied in every installation, and has not received any new information that indicates this has changed. Thus, this option was not considered further as a requirement but for this proposal, as with the 2016 NSPS OOOOa, it is considered to be an acceptable alternative to mitigate methane and VOC emissions where it is technically feasible to apply.

Similarly, another option evaluated as having the potential to achieve methane and VOC emission reductions was to require the collection of emissions in a closed vent system and routing them to a flare or other control device. If the gas is routed to a flare, approximately 95 percent of the methane and VOC would be reduced. The EPA has expressed historically and maintains that combustion is not believed to be a technically feasible control option for reciprocating compressors because, as detailed in the 2011 NSPS OOOO TSD, routing of emissions to a control device can cause positive back pressure on the packing, which can cause safety issues due to gas backing up in the distance piece area and engine crankcase in some designs. The EPA has not identified any new information to indicate that this has changed. Therefore, this option was not considered further as BSER for this proposal.

The remaining two control option approaches that were evaluated further for this proposal include: (1) Specifying a frequency for the replacement of the compressor rod packing (equivalent to the frequency used in the 2016 NSPS OOOOa BSER control level), and (2) monitoring the emissions from the compressor and replacing the rod packing when the results exceed a specified threshold. Both of these approaches would reduce the escape of natural gas from the piston rod. No wastes would be created (other than the worn packing that is being replaced) and no wastewater would be generated.

As noted previously, periodically replacing the packing rings ensures the correct fit is maintained between packing rings and the rod, thereby limiting emissions occurring around the flexible rings that fit around the shaft by recreating a seal against leakage that may have been lost due to wear. The potential emission reductions for reciprocating compressors at gathering and boosting stations, processing plants, and transmission and storage facilities were calculated by comparing the average rod packing emissions with the average emissions from newly installed and worn-in rod packing. As noted above, because the EPA concluded that the cost effectiveness of this option was extremely unreasonable for reciprocating compressors at well sites in previous BSER analyses (see the 2011 NSPS OOOO TSD, section 2.2; 80 FR 56620, September 18, 2015), and since no new information was identified that

[278] U.S. Environmental Protection Agency. *Lessons Learned from Natural Gas STAR Partners. Reducing Methane Emissions from Compressor Rod Packing Systems.* Natural Gas STAR Program. 2006.

would change this outcome as it relates to stand alone well sites, reductions and costs were not re-evaluated in this analysis for reciprocating compressors at production well sites.

The emissions after the replacement of the rod packing were calculated using the methodology used under previous NSPS actions (see NSPS OOOOb and EG TSD, section 7.1). The resulting emission reductions used for the analysis represented the emission reductions expected in the year the rod packing is replaced. It is expected that there would be an increase in the emissions (and decrease in the emission reductions) from a compressor where the rod packing was replaced the second and third years before the next replacement. As noted above, this assumed reduction was between 55 and 80 percent depending on the location of the compressor.

The costs of replacing rod packing were obtained from a Natural Gas STAR Lessons Learned document [279] and the dollars were converted to 2019 dollars. The estimated cost to replace the packing rings in 2019 dollars was estimated to be $1,920 per cylinder. It was assumed that rod packing replacement would occur during planned shutdowns and maintenance, and therefore no additional travel costs would be incurred for implementing a rod packing replacement program. Since the assumed number of cylinders differs for reciprocating compressors at different segments, this means the capital costs also vary. These estimated capital costs are $6,350 at gathering and boosting and transmission stations, $4,800 at processing plants, and $8,650 at storage stations.

The 26,000-hour replacement frequency used for the cost impacts in the 2011 NSPS OOOO TSD and 2016 NSPS OOOOa TSD was determined using a weighted average of the annual percentage of time that reciprocating compressors are pressurized. The weighted average percentage was calculated to be 98.9 percent. This percentage was multiplied by the total number of hours in 3 years to obtain a value of 26,000 hours. This calculates to an average of 3.8 years for gathering and boosting compressors, 3.3 years for processing compressors, 3.8 years for transmission compressors, and 4.4 years for storage compressors. The calculated years were assumed to be the equipment life of the compressor rod packing and were used to calculate the capital recovery factor for each of the segments. Assuming an interest rate of 7 percent, the capital recovery factors were calculated to be 0.3093, 0.3498, 0.3093, and 0.2695 for the gathering and boosting part of production, processing, transmission, and storage segments, respectively.

The capital costs were calculated using the average rod packing cost noted above and the average number of cylinders per compressor (which differs depending on sector segment). The annual capital costs were calculated using the capital costs and the capital recovery factors. The estimated annual costs ranged from $1,700 at processing plants to just over $2,300 at storage facilities. Note that these estimated costs represent the costs, and associated emission reductions, that would occur in the year when the rod packing was changed. There would be no costs for the other two years in the three-year cycle. The costs presented for gathering and boosting segment reciprocating compressors represent the estimated costs assumed for reciprocating compressors located at centralized production facilities.

There are monetary savings associated with the amount of natural gas saved with reciprocating compressor rod packing replacement. Monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement were estimated using a natural gas price of $3.13 per Mcf. Estimated savings were only applied for gathering and boosting stations and processing plants, as it is assumed the owners of the compressor station do not own the natural gas that is compressed at the station.

Using the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, the cost effectiveness of replacement of the reciprocating rod packing within 26,000 hours or 36 months of operation, regardless of the condition of the rod packing, is approximately $290 per ton of methane reduced for gathering and boosting ($100 per ton if gas savings are considered), $90 per ton of methane reduced for the processing segment (net savings if gas savings are considered), $90 per ton of methane reduced for the transmission segment, and $110 per ton of methane reduced for the storage segment. Using the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness of replacement of the reciprocating rod packing within 26,000 hours or 36 months of operation, regardless of the condition of the rod packing, is approximately $140 per ton of methane reduced for gathering and boosting ($50 per ton if gas savings are considered), $45 per ton of methane reduced for the processing segment (net savings if gas savings are considered), $45 per ton of methane reduced for the transmission segment, and $50 per ton of methane reduced for the storage segment.

Using the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, the VOC cost effectiveness of replacement of the reciprocating rod packing within 26,000 hours or 36 months of operation, regardless of the condition of the rod packing, is approximately $1,030 per ton of VOC reduced for gathering and boosting ($380 per ton if gas savings are considered), $330 per ton of VOC reduced for the processing segment (net savings if gas savings are considered), $3,260 per ton of VOC reduced for the transmission segment, and $3,860 per ton of VOC reduced for the storage segment. Using the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness of replacement of the reciprocating rod packing within 26,000 hours or 36 months of operation, regardless of the condition of the rod packing, is approximately $520 per ton of VOC reduced for gathering and boosting ($190 per ton if gas savings are considered), $160 per ton of VOC reduced for the processing segment (net savings if gas savings are considered), $1,630 per ton of VOC reduced for the transmission segment, and $1,930 per ton of VOC reduced for the storage segment.

As an alternative to replacing the rod packing on a fixed schedule, another option is to replace the rod packing when, based on measurements, there are indications that the rod packing is beginning to wear to the point where there is an increased rate of natural gas escaping around the packing to unacceptable levels. This is an approach required by the California Greenhouse Gas Emission Regulation and in Canada. The California Greenhous Gas Emission Regulation requires that the rod packing/seal be tested during periodic inspections and, if the rod packing/seal leak concentration exceeds the specified threshold of 2 scfm/cylinder, repairs must be made within 30 days.[280] Similarly, certain Canadian jurisdictions require periodic monitoring measurements of rod packing vent

[279] EPA (2006). *Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems.* Natural Gas STAR. Environmental Protection Agency.

[280] State of California Air Resources Board (CARB). ''Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.'' Oil and Gas Final Regulation Order (*ca.gov*).

volumes (typically annually) for existing reciprocating compressors. Where specified vent volumes are exceeded, the rules require corrective action be taken to reduce the flow rate to below or equal to a specified limit, as demonstrated by a remeasurement. Vent volume thresholds specified that would result in the need for corrective action vary from 0.49 to 0.81 scfm/cylinder.[281]

This approach is similar to an approach identified in the Natural Gas STAR Program referred to as ''Economic Packing and Piston Rod Replacement.'' [282] Under this approach, facilities use specific financial objectives and monitoring data to determine emission levels at which it is cost effective to replace rings and rods. Benefits of calculating and utilizing this ''economic replacement threshold'' include methane and VOC emission reductions and natural gas cost savings. Using this approach, one Natural Gas STAR partner reportedly achieved savings of over $233,000 annually at 2006 gas prices. An economic replacement threshold approach can also result in operational benefits, including a longer life for existing equipment, improvements in operating efficiencies, and long-term savings. The EPA is not proposing to establish a financial objective or economic replacement threshold in this proposal, but the costs and emission reductions of replacing rod packing based on monitoring from this program were considered in the analysis discussed below.

The elements of such a program include establishing a frequency of monitoring, identifying a threshold where action is required to reduce emissions, and specifying the action for reducing emissions. The option defined by the EPA and evaluated below is for annual monitoring and requiring the replacement of the rod packing if the measured flow rate for any individual cylinder exceeds 2 scfm. This threshold is consistent with California's regulation. However, this option differs from the California regulation in that it would require a complete replacement of the rod packing if this threshold is exceeded, where California allows repair sufficient to reduce the flow rate back below 2 scfm. 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.[283]

We estimated the emission reductions from requiring annual flow rate monitoring and repair/replacement of packing when the measured flow rate exceeds 2 scfm total gas during pressurized operation. Based on California's background regulatory documentation, information provided to the State indicated that the average leak rate for those compressors emitting more than 2 scfm was about 3 scfm during pressurized operation, and less than 2 scfm during pressurized idle and unpressurized states. Therefore, we assumed that the leak rate for compressors emitting more than 2 scfm was about 3 scfm during pressurized operation. As indicated above for the fixed schedule rod packing replacement option, based on the 2011 NSPS OOOO TSD and 2016 NSPS OOOOa TSD, the average emissions from a newly installed rod packing are assumed to be 11.5 scfh per cylinder.[284] Using a ratio of 0.829 methane: Total natural gas ratio, 3 scfm total gas is approximately 2.49 scfm (149.2 scfh) methane. This compressor emission rate, which was used for all industry segments, was converted to an annual mass emission rate by applying segment-specific pressurized factors, then converted to a mass basis.

The estimated percent reduction in methane emissions that would be achievable from reducing 149.2 scfh methane/cylinder to 11.5 scfh methane/cylinder (average emissions from a newly installed rod packing/cylinder) is 92 percent. We applied this percent reduction in methane emissions and estimated reciprocating compressor methane and VOC emission reductions that would be achieved from repairing/replacing rod packing based on the annual flow rate monitoring option. The calculations assume that all cylinders are emitting at 3 scfm, and that the rod packings for all compressor cylinders are replaced. This represents the emission reductions expected for the year in which the rod packings are replaced. Emissions would be expected to increase (and emission reductions decrease) in subsequent years until the next time the annual measurements require that the rod packing be replaced.

The capital and annual costs of replacing the rod packings are the same as presented above for the fixed interval rod packing replacement option. In addition, this option would include the costs associated with the annual flow measurements. The estimated costs of this monitoring are based on the costs for annual flow rate monitoring under GHGRP subpart W for similar flow rate annual measurement requirements ($597). The capital costs associated with replacing compressor rod packing would only occur in the year when packing is required to be replaced. The monitoring costs would be incurred every year.

Additionally, the cost estimates assume that the packing of all compressor cylinders would need to be replaced (which is unlikely to be the case in many instances) and are therefore conservative estimates. Support information for the California rule cites data indicating that approximately 14 percent of compressors measurements indicated a leak rate of over 2 scfm per cylinder. Based on an average of 3.45 cylinders/compressor, California assumed that the packing for 2 cylinders/compressor would need to be replaced to come into compliance with the 2 scfm standard (57.9 percent).[285]

Using the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, the cost effectiveness of the annual monitoring option is approximately $230 per ton of methane reduced for gathering and boosting ($40 per ton if gas savings are considered), $110 per ton of methane reduced for the processing segment (net savings if gas savings are considered), $100 per ton of methane reduced for the transmission segment, and $110 per ton of methane reduced for the storage segment. Using the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness of replacement of the reciprocating rod packing based on the annual monitoring approach is approximately $110 per ton of methane reduced for gathering and boosting ($20 per ton if gas savings are considered), $50 per ton of methane reduced for the processing segment (net savings if gas savings are considered), $50 per ton of methane reduced for the transmission

[281] Canadian Federal standards: *http://gazette.gc.ca/rp-pr/p2/2018/2018-04-26-x1/pdf/g2-152x1.pdf;* Discussion Draft Regulation 26.11.41 (*maryland.gov*); *MAP-Technical-Report-December-19-2019-FINAL.pdf* (*nm.gov*).

[282] U.S. Environmental Protection Agency. *Lessons Learned from Natural Gas STAR Partners. Reducing Methane Emissions from Compressor Rod Packing Systems.* Natural Gas STAR Program. 2006.

[283] 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. pgs. 96–97.

[284] 2011 TSD, pg. 6–13.

[285] Based on Appendix B. Economic Analysis. State of California. Air Resources Board. *Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.* pg. B–28. Notice Package for Oil and Gas Reg (*ca.gov*); State of California. *Air Resources 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. Date of Release: May 31, 2016. pg. 99.

segment, and $60 per ton of methane reduced for the storage segment.

Using the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, the VOC cost effectiveness of the annual monitoring option is approximately $810 per ton of VOC reduced for gathering and boosting ($160 per ton if gas savings are considered), $380 per ton of VOC reduced for the processing segment (net savings if gas savings are considered), $3,700 per ton of VOC reduced for the transmission segment, and $4,100 per ton of VOC reduced for the storage segment. Using the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness of replacement of the reciprocating rod packing based on the annual monitoring approach is approximately $410 per ton of VOC reduced for gathering and boosting ($80 per ton if gas savings are considered), $190 per ton of VOC reduced for the processing segment (net savings if gas savings are considered), $1,850 per ton of VOC reduced for the transmission segment, and $2,040 per ton of VOC reduced for the storage segment.

We also assessed the incremental cost effectiveness of the annual monitoring option compared to the fixed 3-year/26,000 replacement schedule. Using the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, the incremental cost effectiveness (without natural gas savings) from the fixed replacement option to the annual monitoring option for methane is approximately $130 per ton for gathering and boosting stations, $210 per ton for processing plants, $180 per ton for transmission stations, and $140 per ton for storage facilities. For VOC, the incremental cost effectiveness is approximately $480 per ton for gathering and boosting stations, $750 per ton for processing plants, $6,600 per ton for transmission stations, and $5,150 per ton for storage facilities.

The cost effectiveness of both options (fixed schedule and annual monitoring) are reasonable for methane and VOC using either the single pollutant or multipollutant approach. The incremental cost effectiveness in going from the fixed schedule option to the annual monitoring option is reasonable for all scenarios, with the exception of VOC for transmission stations. Therefore, based on the consideration of the costs in relation to the emission reductions, the EPA finds that the annual monitoring option is the most reasonable option.

Further, as discussed above, California requires reciprocating compressor annual rod packing flow rate monitoring and repair and or replacement of the packing where flow rate monitoring indicates a measurement that exceeds 2 scfm. This further supports the reasonableness of a monitoring program.

Neither the fixed schedule rod packing replacement option nor the rod packing replacement based on annual monitoring option would result in secondary emissions impacts as both options would reduce the escape of natural gas from the piston rod. No wastes would be created (other than the worn packing that is being replaced) and no wastewater would be generated. An advantage related to the replacement of rod packing for reciprocating compressors based on annual rod packing monitoring is that it would only require replacement of the rod packing where monitoring of the rod packing indicates wear and increasing flow rate/emissions to unacceptable levels. This optimizes the output of capital expenditures to focus on emissions control where an increased emissions potential is identified.

In light of the above we determined that annual rod pack flow rate monitoring and replacement of the packing where flow rate monitoring indicates a measurement that exceeds 2 scfm represents BSER for NSPS OOOOb for this proposal for all segments including reciprocating compressors located at centralized productions facilities (with the exception of compressors at stand-alone well sites). As in the 2016 NSPS OOOOa, the EPA is proposing to allow the collection and routing of emissions to a process as an alternative standard because that option would achieve emission reductions equivalent to, or greater than, the proposed standard for NSPS OOOOb.

The affected facility based on EPA's review would continue to be each reciprocating compressor not located at a well site, or an adjacent well site and servicing more than one well site. As discussed above, the EPA is proposing a new definition for a ''centralized production facility''. The EPA is proposing to define centralized production facilities separately from well sites because the number and size of equipment, particularly reciprocating and centrifugal compressors, is larger than standalone well sites which would not be included in the proposed definition of ''centralized production facilities''. Thus, the EPA is proposing that reciprocating compressors located at centralized production facilities would be subject to the standards in NSPS in OOOOb, but reciprocating compressors at well sites (standalone well sites) would not.

2. EG OOOOc

The EPA evaluated BSER for the control of methane from existing reciprocating compressors (designated facilities) in all segments in the Crude Oil and Natural Gas source category covered by the proposed NSPS OOOOb and translated the degree of emission limitation achievable through application of the BSER into a proposed presumptive standard for these facilities that essentially mirrors the proposed NSPS OOOOb.

First, based on the same criteria and reasoning as explained above, the EPA is proposing to define the designated facility in the context of existing reciprocating compressors as those that commenced construction on or before November 15, 2021. Based on information available to the EPA, we did not identify any factors specific to existing sources that would indicate that the EPA should alter this definition as applied to existing sources. Next, the EPA finds that the control measures evaluated for new sources for NSPS OOOOb are appropriate for consideration for existing sources under the EG OOOOc. The EPA finds no reason to evaluate different, or additional, control measures in the context of existing sources because the EPA is unaware of any control measures, or systems of emission reduction, for reciprocating compressors that could be used for existing sources but not for new sources. Next, the methane emission reductions expected to be achieved via application of the control measures identified above to new sources are also expected to be achieved by application of the same control measures to existing sources. The EPA finds no reason to believe that these calculations would differ for existing sources as compared to new sources because the EPA believes that the baseline emissions of an uncontrolled source are the same, or very similar, and the efficiency of the control measures are the same, or very similar, compared to the analysis above. This is also true with respect to the costs, non-air environmental impacts, energy impacts, and technical limitations discussed above for the control options identified.

The EPA has not identified any costs associated with applying these controls at existing sources, such as retrofit costs, that would apply any differently than, or in addition to, those costs assessed above regarding application of the identified controls to new sources. The cost effectiveness values for the proposed presumptive standard of replacement of the rod packing based on an annual monitoring threshold is approximately $230 per ton of methane reduced ($40 per ton if gas savings are considered) for the gathering and boosting segment (including reciprocating compressors located at centralized tank facilities), $110 per ton of methane reduced for the processing segment (net savings if gas savings are considered), $100 per ton of methane reduced for the transmission segment, and $110 per ton of methane reduced for the storage segment.

In summary, the EPA did not identify any factors specific to existing sources, as opposed to new sources, that would alter the analysis above for the proposed NSPS OOOOb as applied to the designated pollutant (methane) and the designated facilities (reciprocating compressors). As a result, the proposed presumptive standard for existing reciprocating compressors is as follows.

For reciprocating compressors in the gathering and boosting segment (including reciprocating compressors located at centralized tank facilities), processing, and transmission and storage segments, the presumptive standard is replacement of the rod packing based on an annual monitoring threshold. Specifically, the presumptive standard would require an owner or operator of a reciprocating compressor designated facility to monitor the rod packing flow rate annually. When the measured leak rate exceeds 2 scfm (in pressurized mode), the standard would require replacement of the rod packing. As an alternative, the presumptive standard would be routing rod packing emissions to a process via a closed vent system under negative pressure.

F. Proposed Standards for Centrifugal Compressors

1. NSPS OOOOb

a. Background

The 2012 NSPS OOOO and the 2016 NSPS OOOOa applied to each wet seal compressor not located at a well site, or an adjacent well site and servicing more than one well site. The 2016 NSPS OOOOa required methane and VOC emissions be reduced from each centrifugal compressor wet seal fluid degassing system by 95.0 percent. Compliance with this requirement allowed routing of emission from the wet seal fluid degassing system to a control device or to a process. Dry seal compressors were not subject to requirements under the 2016 NSPS OOOOa.

In determining BSER for wet seal compressors in 2016, the EPA determined that the previous determination for NSPS OOOO conducted in 2011/2012 still represented BSER for the control of VOC in 2016. In addition, the EPA determined that analogous control of methane represented BSER. In the 2012 determinations, the EPA conducted analyses of the cost and emission reductions of (1) requiring the conversion of a wet seal system to a dry seal system, and (2) routing to a control device or process. The 2011 NSPS OOOO rule (76 FR 52738, 52755, August 23, 2011) proposed an equipment standard that would have required the use of dry seals to limit the VOC emissions from new centrifugal compressors. At that time, the EPA solicited comments on the emission reduction potential, cost, and any technical limitations for the option of routing the gas back to a low-pressure fuel stream to be combusted as fuel gas. In addition, in 2011 (76 FR 52738), the EPA solicited comments on whether there are situations or applications where a wet seal is the only option, because a dry seal system is infeasible or otherwise inappropriate. The EPA received information indicating that the integration of a centrifugal compressor into an operation may require a certain compressor size or design that is not available in a dry seal model, and in the case of capture of emissions with routing to a process, there may not be down-stream equipment capable of handling a low-pressure fuel source. In the final 2012 NSPS OOOO rule, the EPA made the determination that the replacement of wet seals with dry seals and routing to a process was not technically feasible or practical for some centrifugal compressors, and also that the costs per ton of emissions reduced were reasonable for routing emissions to a control device or process. No other more stringent control options were evaluated at that time. During the development of the 2016 NSPS OOOOa rule, the EPA reviewed available information on control options for wet seal compressors and did not identify any new information to indicate that this has changed.

For this review, the EPA also focused on these control options. BSER was evaluated for wet-seal centrifugal compressors at gathering and boosting stations (considered to be representative of emissions from centrifugal compressors at centralized production facilities) in the production segment, at natural gas processing plants, and at sites in the transmission and storage segment. During the development of the 2012 NSPS OOOO and 2016 NSPS OOOOa rulemakings, our data indicated that there were no centrifugal compressors located at well sites. Since the 2012 NSPS OOOO and 2016 NSPS OOOOa rulemakings, we have not received information that would change our understanding that there are no centrifugal compressors in use at well sites.

However, as discussed in section XI.L (Centralized Production Facilities) of this preamble, the EPA believes the definition of ''well site'' in NSPS OOOOa may cause confusion regarding whether centrifugal compressors located at centralized production facilities are also exempt from the standards. The EPA is proposing a new definition for a ''centralized production facility''. The EPA is proposing to define centralized production facilities separately from well sites because the number and size of equipment, particularly reciprocating and centrifugal compressors, is larger than standalone well sites which would not be included in the proposed definition of ''centralized production facilities''. This proposal is necessary in the context of centrifugal compressors to distinguish between these compressors at centralized production facilities where the EPA has determined that the standard should apply, and compressors at standalone well sites where the EPA has determined that the standard should not apply. In our current analysis, described below, we consider the centrifugal compressor gathering and boosting segment emission factor as being representative of centrifugal compressor emissions located at centralized production facilities. As such, the EPA is proposing that centrifugal compressors located at centralized production facilities would be subject to the standards in NSPS OOOOb and the EG in subpart OOOOc, but centrifugal compressors at well sites (standalone well sites) would not.

In addition to the requirement to reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent, the 2016 NSPS OOOOa requires compressor components to be monitored as fugitive emissions components and leaks found are to be repaired under the fugitive emissions monitoring requirements of 40 CFR 60.5397a. The monitoring frequency depends on source (*i.e.,* well sites, compressor stations) and sector segment. These fugitive emissions components were not considered part of the centrifugal compressor affected facility.

Based on the EPA's review of NSPS OOOOa, we are proposing that BSER continues to be that methane and VOC emissions be reduced from each centrifugal compressor wet seal fluid degassing system by 95.0 percent.

b. Description

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the natural gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Some centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and adsorbs some compressed natural gas that may be released to the atmosphere during the seal oil recirculation process. Off gassing of entrained natural gas from wet seal centrifugal compressors is not suitable for sale and is either released to the atmosphere, flared, or routed back to a process.

Some centrifugal compressors utilize dry seal systems. Dry seal systems minimize leakage by using the opposing force created by hydrodynamic grooves and springs. The hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates at high speed, compressed natural gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This natural gas is pumped between the grooves in the rotating and stationary rings. The opposing force of high-pressure natural gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little natural gas can leak. While the compressor is operating, the rings are not in contact with each other and, therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case. Historically, the EPA has considered dry seal centrifugal compressors to be inherently low-emitting and has never required control of emissions from dry seal compressors. The EPA has received feedback,[286] however, that there are some wet seal compressor system designs that are also low emitting when compared to dry seal compressors and is soliciting comment on lower emitting wet seal compressor system designs and dry seal compressor emissions in this proposed action.

The 2021 U.S. GHGI estimates over 166,700 metric tpy of methane emissions in 2019 from compressors from natural gas systems. For the natural gas processing and transmission segments, wet seal compressor methane emissions are estimated to be about 78,700 metric tons and dry seal compressor methane estimated emissions are estimated to be about 88,000 metric tons.[287] The wet seal and dry seal compressor methane emission estimates reflect the increasing prevalence of the use of dry seals over wet seals and emissions control requirements that require the control of emissions from wet seal compressors. The methane emissions from centrifugal compressors represent 3 percent of the total methane emissions from natural gas systems in the Oil and Natural Gas Industry sector.

c. Affected Facility

For purposes of the NSPS, the centrifugal compressor affected facility is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under the proposed rule for NSPS OOOOb. As discussed above, the EPA is proposing that the affected facility includes centrifugal compressors located at centralized production facilities and the affected facility exception for ''a well site, or an adjacent well site servicing more than one well site'' applies to standalone well sites and not centralized production facilities.

d. 2021 BSER Analysis

The methodology we used for estimating emissions from compressors is consistent with the methodology developed for the 2012 NSPS OOOO BSER analysis, which was also used to support the 2016 NSPS OOOOa BSER.[288] The wet-seal centrifugal compressor methane uncontrolled emission factors are based on the volumetric emission factors used for the GHGI, which were converted to a mass emission rate using a density of 41.63 pounds of methane per thousand cubic feet. The VOC emissions were calculated using the ratio of 0.278 pounds VOC per pound of methane for the production and processing segments, and 0.0277 pounds VOC per pound of methane for the transmission and storage segment. The resulting baseline uncontrolled emissions per centrifugal compressor are 157 tpy methane (43.5 tpy VOC) from wet-seal compressors at gathering and boosting sites, 211 tpy methane (58.7 tpy VOC) from wet-seal compressors at natural gas processing plants, 157 tpy methane (4.3 tpy VOC) from wet-seal compressors at transmission compressor stations, and 117 (3.24 tpy VOC) from wet-seal compressors at storage facilities. Since the emission factors for dry seal compressors are approximately lower than wet seal compressors,[289] the EPA considered requiring dry seals as a replacement to wet seals as a control option in 2011. The EPA proposed dry seals as a replacement to wet seals to control VOC emissions at that time. Based on comments received on the proposal that dry seal compressors were not feasible in all instances based on costs and technical reasons, the EPA did not finalize the proposal that dry seal compressors represented BSER. Instead, the EPA separately evaluated the control options for wet seal compressors (77 FR 49499–49500, 49523, August 16, 2012). In the 2015 NSPS OOOOa proposed rule, the EPA maintained that available information since the 2012 NSPS OOOO rule continued to show that dry seal compressors cannot be use in all circumstances. The EPA has not identified any new information since that time that indicates that dry seal compressors as a replacement for wet seal compressors is technically feasible in all circumstances. Thus, we did not evaluate the replacement of a wet seal system with a dry seal system as BSER for controlling emissions from wet seal systems for the NSPS OOOOb proposal.

In addition to soliciting comment and information on lower-emitting wet seal compressor designs (that emit less than dry seal compressors), the EPA is soliciting information on dry seal compressor emissions. Feedback received (noted above) on lower emitting wet seal compressor designs included concern that lower emitting wet seal systems were being replaced by higher emitting (but still low emitting) dry seal systems because they were not subject to the NSPS. Given that the trend has been that wet seal compressor systems are increasingly being replaced by dry seal compressor systems, the EPA solicits comments on dry seal compressor emissions and whether/and

[286] Conference Call. Prepared by Tora Consulting. December 19, 2018.

[287] U.S. Environmental Protection Agency. Inventory of U.S. Greenhouse Gas Emissions and Sinks (1990–2019). Published in 2021. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019.

[288] 2011 NSPS OOOO TSD, section 6.2.2; 2016 NSPS OOOOa TSD, section 7.2.2.

[289] 2011 NSPS OOOO TSD, Table 6–2, pg. 6–4; 2016 NSPS OOOOa TSD, Table 7–2, pg. 104.

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 also solicits comment on whether owners and operators implement standard operating procedures to identify and correct operational or malfunction conditions that have the potential to increase emissions from dry seal systems. Finally, the EPA solicits comments on whether we should consider evaluating BSER and developing NSPS standards for dry seal compressors.

The control options to reduce emissions from centrifugal compressors evaluated include control techniques that reduce emissions from leaking of natural gas from wet seal compressors by capturing leaking gas and route it either to (1) a control device (combustion device), or (2) to the process. We evaluated the costs and impacts of both of these options.

Combustion devices are commonly used in the Crude Oil and Natural Gas Industry to combust methane and VOC emission streams. Combustors are used to control VOC and methane emissions in many industrial settings, since the combustor can normally handle fluctuations in concentration, flow rate, heating value and inert species content.[290] A combustion device generally achieves 95 percent reduction of methane and VOC when operated according to the manufacturer instructions. 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. This option was determined to be BSER under the 2011 NSPS OOOO (77 FR 49490, August 16, 2012) and 2016 NSPS OOOOa rules. The combustion of the recovered gas creates secondary emissions of hydrocarbons (NO_X, CO_2, 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 costs for the installation of a combustion device (an enclosed flare for the analysis) were calculated using the methodology in the EPA Control Cost Manual.[291] The capital costs of a flare and the equipment (closed vent system) necessary to route emissions to the flare are based on costs from the 2011 NSPS OOOO TSD and 2016 NSPS OOOOa TSD. These costs were updated to 2019 dollars. The updated capital costs of $80,930 were annualized at 7 percent based on an equipment life of 10 years. The total annualized capital costs were estimated to be $11,520. The annual operating costs are also based on the 2011 NSPS OOOO TSD and 2016 NSPS OOOOa TSD. These costs were updated to 2019 dollars. The 2019 annual operating costs were estimated to be $117,160. The combined annualized capital and operating costs per compressor per year is an estimated $128,680. There is no cost savings estimated for this option because the recovered natural gas is combusted. The costs presented for gathering and boosting segment centrifugal compressors represent the estimated costs assumed for centrifugal compressors located at centralized production facilities.

Using the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, the cost effectiveness of routing emissions from a wet seal system to a new flare for methane emissions is $870 per ton of methane reduced for the transmission segment and gathering and boosting, $640 per ton of methane reduced for the processing segment, and $1,160 per ton of methane reduced for the storage segment. Using the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness of routing emissions from a wet seal system to a new flare for methane emissions is $430 per ton of methane reduced for the transmission segment and gathering and boosting, $320 per ton of methane reduced for the processing segment, and $580 per ton of methane reduced for the storage segment.

Using the single-pollutant approach, where all the costs are assigned to the reduction of one pollutant, the cost effectiveness of routing emissions from a wet seal system to a new flare for VOC emissions is $3,100 per ton of VOC reduced for gathering and boosting, $2,300 per ton of VOC reduced for the processing segment, $31,200 per ton of VOC reduced for the transmission segment, and $41,800 per ton of VOC reduced for the storage segment. Using the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness of routing emissions from a wet seal system to a new flare for VOC emissions is $1,600 per ton of VOC reduced for gathering and boosting, $1,200 per ton of VOC reduced for the processing segment, $15,600 per ton of VOC reduced for the transmission segment, and $20,900 per ton of VOC reduced for the storage segment.

In addition to an owner or operator having the option to capture emissions and routing to a new combustion control device, a less costly option that may be available could be for owners and operators to capture and route emissions to a combustion control device installed for another source (*e.g.,* a control device that is already on site to control emissions from another emissions source). The costs, which are provided in the NSPS OOOOb and EG TSD for this rulemaking, would be for the ductwork to capture the emissions and route them to the control device. The analysis assumes that the combustion control device on site achieves a 95 percent reduction in emissions of methane and VOC.

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 other beneficial use (referred to collectively as routing to a process). Routing to a process would entail routing emissions via a closed vent system 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. Emissions that are routed to a process are assumed to result in the same or greater emission reductions as would have been achieved had the emissions been routed through a closed vent system to a combustion device.[292] For purposes of this analysis, we assumed that routing methane and VOC emissions from a wet seal fluid degassing system to a process reduces VOC emissions greater than or equal to a combustion device (*i.e.,* greater than or equal to 95 percent). There are no secondary impacts with the option to control emissions from centrifugal wet seals by capturing gas and routing to the process.

[290] U.S. Environmental Protection Agency. AP 42, Fifth Edition, Volume I, *Chapter 13.5 Industrial Flares.* Office of Air Quality Planning & Standards. 1991.

[291] U.S. Environmental Protection Agency. *OAQPS Control Cost Manual: Sixth Edition* (EPA 452/B–02–001). Research Triangle Park, NC.

[292] U.S. Environmental Protection Agency. Control Techniques Guidelines for the Oil and Natural Gas Industry. Office of Air Quality Planning and Standards, Sector Policies and Programs Division. October 2016. EPA–453/B–16–001. (2016 CTG). pgs. 5–19 to 5–20.

The capital cost of a system to route the seal oil degassing system to a process is estimated to be $26,210 ($2,019),[293] The estimated costs include an intermediate pressure degassing drum, new piping, gas demister/filter, and a pressure regulator for the fuel line. The annual costs were estimated to be $2,880 (without savings) assuming a 15-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 Mcf, which resulted in annual savings of $27,000 per year at gathering and boosting stations and $36,400 per year at processing plants. The annual cost savings are much greater than the annual costs, which results in an overall savings when they are considered.

Using the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, the cost effectiveness (without natural gas savings) of routing emissions from a wet seal system to a process for methane emissions is approximately $19 per ton of methane reduced for the transmission segment and gathering and boosting, $14 per ton of methane reduced for the processing segment, and $26 per ton of methane reduced for the storage segment. Using the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness (without natural gas savings) of routing emissions from a wet seal system to a process for methane emissions is approximately $10 per ton of methane reduced for the transmission segment and gathering and boosting, $7 per ton of methane reduced for the processing segment, and $13 per ton of methane reduced for the storage segment. As noted above, there is an overall net savings if the value of the natural gas recovered is considered.

Using the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, the cost effectiveness (without natural gas savings) of routing emissions from a wet seal system to a process for VOC emissions is approximately $70 per ton of VOC reduced for gathering and boosting, $50 per ton of VOC reduced for the processing segment, $700 per ton of VOC reduced for the transmission segment, and $940 per ton of VOC reduced for the storage segment. Using the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness (without natural gas savings) of routing emissions from a wet seal system to a process for VOC emissions is approximately $35 per ton of VOC reduced for gathering and boosting, $26 per ton of VOC reduced for the processing segment, $350 per ton of VOC reduced for the transmission segment, and $470 per ton of VOC reduced for the storage segment. As noted above, there is an overall net savings if the value of the natural gas recovered is considered.

The cost effectiveness of both options (routing emissions to a combustion device or to a process) are reasonable for methane for all of the evaluated segments, using both the single pollutant and multipollutant approaches. The cost effectiveness of routing emissions to a process are also reasonable for VOC for all of the evaluated segments, using both the single pollutant and multipollutant approaches. For routing emissions to a combustion device, the cost effectiveness is reasonable for the gathering and boosting and processing segments using the single pollutant and multipollutant approaches. Based on the consideration of the costs in relation to the emission reductions of both methane and VOC, the EPA finds that requiring emissions to be reduced from each centrifugal compressor using a wet seal by at least 95 percent (which can be achieved by either option) continues to be reasonable in the gathering and boosting (considered to be representative of emissions/costs from centrifugal compressors at centralized production facilities). processing, transmission and storage segments.

The 2012 NSPS OOOO and the 2016 NSPS OOOOa require emissions be reduced from each centrifugal compressor wet seal fluid degassing system by at least 95.0 percent by routing emissions to a control device or to a process. States have generally adopted/incorporated this NSPS level of control (or a level of control that is substantially similar) in their State regulations for the control of emissions from centrifugal compressor sources using wet seals. Owners and operators have successfully met this standard for almost a decade. These facts further demonstrate the reasonableness of this level of control. In the discussion above, we reviewed two options to reduce emissions from wet seal compressors that are both current regulatory options under the 2016 NSPS OOOOa: (1) Capturing leaking gas and route to a combustion device (flare), or (2) capturing leaking gas and route to the process. Under the 2016 NSPS OOOOa, the level of control determined based on BSER was that methane and VOC emissions be reduced from each centrifugal compressor wet seal fluid degassing system by 95 percent or greater. The EPA has not identified any other control options or any other Federal, State, or local requirements that would achieve a greater reduction in methane and VOC emissions from centrifugal compressor wet seal systems. Although capturing leaking gas and routing to the process has the advantage of both reducing emissions by at least 95 percent or greater and capturing the natural gas (resulting in a natural gas savings), the EPA has received feedback in the development of the 2012 NSPS OOOO rule that this option may not be a viable option in situations where there may not be down-stream equipment capable of handling a low-pressure fuel source. During the development of the 2016 NSPS OOOOa rule, the EPA reaffirmed that information since the development of the 2012 NSPS OOOO rule continues to show that capturing leaking gas and routing to the process cannot be used in all circumstances. No new information has been identified since the development of the 2016 NSPS OOOOa rule to indicate that capturing leaking gas and routing to the process can be achieved in all circumstances (80 FR 56619, September 18, 2015). Thus, by establishing a 95 percent methane and VOC emissions control level as BSER, an owner or operator has the option of routing emissions to a process where it is a viable option, or to a combustion device where routing to a process is not a viable option. 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, CO_2, and CO emissions).

The costs, emission reductions, and cost effectiveness values were presented above for collecting the wet seal compressor emissions and routing them to both a combustion device and to a process to achieve at least a 95 percent control. The EPA considers the cost effectiveness of both of these control options reasonable across all segments evaluated (*i.e.,* the gathering and boosting portion of production, processing, transmission, storage) for the reduction of methane emissions under the single pollutant approach and multipollutant approach. As discussed

[293] 2011 NSPS OOOO TSD, pg. 114; 2016 CTG, pg. 5–20.

above, in our current analysis, we consider the centrifugal compressor gathering and boosting segment emission factor as being representative of centrifugal compressor emissions located at centralized production facilities. Thus, the cost analysis performed for the gathering and boosting segment represents the estimated costs of evaluated options for centrifugal compressors with wet seals located at centralized storage facilities.

In light of the above, we determined that reducing methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent or greater continues to represent BSER for NSPS OOOOb for this proposal. The affected facility based on EPA's review would continue be each wet seal compressor not located at a well site, or an adjacent well site and servicing more than one well site. As discussed above, the EPA is proposing a new definition for a ''centralized production facility''. The EPA is proposing to define centralized production facilities separately from well sites because the number and size of equipment, particularly reciprocating and centrifugal compressors, is larger than standalone well sites which would not be included in the proposed definition of ''centralized production facilities''. Thus, the EPA is proposing that centrifugal compressors located at centralized production facilities would be subject to the standards in the NSPS in OOOOb, but centrifugal compressors at well sites (standalone well sites) would not.

2. EG OOOOc

The EPA evaluated BSER for the control of methane from existing centrifugal compressors using wet seals (not located at a well site, or an adjacent well site and servicing more than one well site) (designated facilities) in all segments in the Crude Oil and Natural Gas source category covered by the proposed NSPS OOOOb and translated the degree of emission limitation achievable through application of the BSER into a proposed presumptive standard for these facilities that essentially mirrors the proposed NSPS OOOOb.

First, based on the same criteria and reasoning as explained above, the EPA is proposing to define the designated facility in the context of existing centrifugal compressors using wet seals (not located at a well site, or an adjacent well site and servicing more than one well site) as those that commenced construction on or before November 15, 2021. Based on information available to the EPA, we did not identify any factors specific to existing sources that would indicate that the EPA should alter this definition as applied to existing sources. Next, the EPA finds that the control measures evaluated for new sources for NSPS OOOOb are appropriate for consideration for existing sources under the EG OOOOc. The EPA finds no reason to evaluate different, or additional, control measures in the context of existing sources because the EPA is unaware of any control measures, or systems of emission reduction, for centrifugal compressors that could be used for existing sources but not for new sources. Next, the methane emission reductions expected to be achieved via application of the control measures identified above to new sources are also expected to be achieved by application of the same control measures to existing sources. The EPA finds no reason to believe that these calculations would differ for existing sources as compared to new sources because the EPA believes that the baseline emissions of an uncontrolled source are the same, or very similar, and the efficiency of the control measures are the same, or very similar, compared to the analysis above. This is also true with respect to the costs, non-air environmental impacts, energy impacts, and technical limitations discussed above for the control options identified.

The EPA has not identified any costs associated with applying these controls at existing sources, such as retrofit costs, that would apply any differently than, or in addition to, those costs assessed above regarding application of the identified controls to new sources. The cost effectiveness values for the proposed presumptive standard of reducing methane emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent or greater are based on the cost effectiveness of routing emissions from a wet seal system to a flare or to a process. The cost effectiveness of routing emissions from a wet seal system to a new flare for methane emissions is $870 per ton of methane reduced for the transmission segment and gathering and boosting, $640 per ton of methane reduced for the processing segment, and $1,160 per ton of methane reduced for the storage segment. The cost effectiveness (without natural gas savings) of routing emissions from a wet seal system to a process for methane emissions is approximately $19 per ton of methane reduced for the transmission segment and gathering and boosting, $14 per ton of methane reduced for the processing segment, and $26 per ton of methane reduced for the storage segment.

In summary, the EPA did not identify any factors specific to existing sources, as opposed to new sources, that would alter the analysis above for the proposed NSPS OOOOb as applied to the designated pollutant (methane) and the designated facilities (centrifugal compressors using wet seals). As a result, the proposed presumptive standard for existing centrifugal compressors using wet seals is as follows.

For centrifugal compressors using wet seals in the gathering and boosting segment (including centrifugal compressors using wet seals located at centralized tank facilities), processing, and transmission and storage segments, the presumptive standard is to reduce methane emissions by at least 95 percent. An owner or operator can meet this presumptive standard by routing methane emissions to a control device or process that reduces emissions by at least 95 percent. As discussed previously, the EPA is proposing a new definition for a ''centralized production facility''. The EPA is proposing to define centralized production facilities separately from well sites because the number and size of equipment, particularly reciprocating and centrifugal compressors, is larger than standalone well sites which would not be included in the proposed definition of ''centralized production facilities''. Thus, the EPA is proposing that centrifugal compressors located at centralized production facilities would be subject to the standards in the EG in OOOOc, but centrifugal compressors at well sites (standalone well sites) would not.

G. Proposed Standards for Pneumatic Pumps

1. NSPS OOOOb

a. Background

In the 2016 NSPS OOOOa, the EPA established GHG (in the form of limitations on methane emissions) and VOC standards for natural gas-driven diaphragm pneumatic pumps located at well sites. This standard required that natural gas emissions be reduced by 95.0 percent by routing to an existing control device if: (1) A control device was onsite, (2) the control device could achieve a 95.0 percent reduction, and (3) it was technically feasible to route the emissions to the control device. The standard did not require the installation of a control device solely for the purpose of complying with the 95.0 percent reduction for the emissions from pneumatic pumps. It also allowed the option of routing emissions to a process. At natural gas processing plants, the EPA established a standard that required a natural gas emission rate of zero (*i.e.,* that prohibited methane and VOC emissions from pneumatic pumps).

As a result of the review of these requirements and the previous BSER determination, the EPA is proposing methane and VOC standards in NSPS OOOOb for natural gas-driven pneumatic pumps located in all segments of the source category. Specifically, the EPA is proposing that each natural gas driven pneumatic pump is an affected facility. The EPA is proposing that methane and VOC emissions from natural gas-driven diaphragm and piston pumps at well sites and all other sites in the production segment be reduced by 95.0 percent or routed to a process, provided that there is an existing control device onsite or it is technically feasible to route the emissions to a process. For natural gas driven pneumatic pumps at natural gas transmission stations and natural gas storage facilities, the same requirement applies, but only to diaphragm pumps. The EPA is proposing to retain the technical infeasibility provisions of NSPS OOOOa for purposes of NSPS OOOOb. If there is a control device onsite,[294] the owner or operator is not required to route emissions to that control device if it is not technically feasible to do so, even for new construction sites which the EPA had previously referred to as ''greenfield'' sites. The EPA is also proposing to retain in NSPS OOOOb the exception to the 95.0 percent reduction requirement if there is a control device onsite that it is technically feasible to route to that cannot achieve that level of reduction but can achieve a lower level of reductions. In those situations, the emissions from the pump are still to be routed to the control device and controlled at the level that the device can achieve. The EPA is also proposing a prohibition on methane and VOC emissions from pneumatic pumps (diaphragm and piston pumps) at natural gas processing plants. While zero emissions pneumatic pumps would not technically be affected facilities because they are not driven by natural gas, owners and operators should maintain documentation if they would like to be able to demonstrate to permit writers or enforcement officials that there are no methane or VOC emissions from the pumps and that these pumps are not affected facilities subject to the rule.

This BSER for reducing methane and VOC from pneumatic pumps are the same as those for the 2016 NSPS OOOOa, except that (1) the EPA determined that the NSPS OOOOa levels of control also represent BSER for diaphragm pumps at all sites in the production segment (including gathering and boosting stations), and for all transmission and storage sites, and (2) the EPA determined that the NSPS OOOOa levels of control also represent BSER for piston pumps (in addition to diaphragm pumps) in the production segment and at natural gas processing plants.

As discussed below, a primary reason that the EPA is unable to conclude that requiring a natural gas emission rate of zero for production and transmission and storage facilities is BSER at this time is because proven technologies that eliminate natural gas emissions rely on electricity to function. In contrast to pneumatic controllers, our review of information that has become available since the promulgation of the 2016 NSPS OOOOa standards, including State-level regulations for pneumatic pumps, does not demonstrate that zero emission technology for pneumatic pumps would be feasible at sites that lack access to onsite power. The EPA is specifically soliciting comments on the possibility of subcategorizing production and natural gas transmission and storage sites into those sites that have access to onsite power and those that do not, and then determining BSER separately for each subcategory. Further, the EPA is soliciting comment on how, if at all, the proposed NSPS OOOOb standards for pneumatic controllers might factor into how the EPA ought to evaluate the possibility of requiring a natural gas emission rate of zero for pneumatic pumps in the production and transmission and storage segments. For example, if a site installs a solar-powered system to operate their controllers, then could that same system provide power to the pumps such that all pumps at the site could have zero emissions of natural gas?

b. Description

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. Pumps used for heat tracing/freeze protection circulate hot glycol or other heat-transfer fluids in tubing covered with insulation to prevent freezing in pipelines, vessels and tanks. These heat tracing/freeze protection pumps are usually diaphragm pumps. Chemical injection pumps are designed to inject precise amounts of chemical into a process stream to regulate operations of a plant and protect the equipment. Typical chemicals injected in an oil or gas field are biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers, and H_2S scavengers. These chemicals are normally injected at the wellhead and into gathering lines or at production separation facilities. Since the injection rates are typically small, the pumps are also small. They are often attached to barrels containing the chemical being injected. These chemical injection pumps are primarily piston pumps, although they can be small diaphragm pumps. Examples of the use of pneumatic pumps to transfer bulk liquids at oil and natural gas production sites include pumping motor oil or pumping out sumps. Pumps used for these purposes ae typically diaphragm pumps.

Glycol dehydrator pumps recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber. Glycol dehydrator pumps are controlled under the oil and gas NESHAPs (40 CFR part 63, subparts HH and HHH), are not included as affected facilities for the 2016 NSPS OOOOa and were not included in the review for proposed NSPS OOOOb.

Both diaphragm and piston pumps are positive displacement reciprocating pumps, meaning they use contracting and expanding cavities to move fluids. These pumps work by allowing a fluid (*e.g.,* the heat transfer fluid, demulsifier, corrosion inhibitor, etc) to flow into an enclosed cavity from a low-pressure source, trapping the fluid, and then forcing it out into a high-pressure receiver by decreasing the volume of the cavity. The piston and diaphragm pumps have two major components, a driver side and a motive side, which operate in the same manner but with different reciprocating mechanisms. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm to draw fluid into the pump. The motive side of the pump delivers the energy to the fluid being moved in order to discharge

[294] For the same reasons discussed in section X.B.2, the EPA is proposing that boilers and process heaters are not control devises for purposes of controlling emissions from pneumatic pumps.

the fluid from the pump. The natural gas leaving the exhaust port of the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas.

Diaphragm pumps work by flexing the diaphragm out of the displacement chamber, and piston pumps typically include plunger pumps with a large piston on the gas end and a smaller piston on the liquid end to enable a high discharge pressure with a varied but much lower pneumatic supply gas pressure.

As noted above, energy is supplied to the driver side of the pump to operate the piston or diaphragm. Commonly, this energy is provided by pressurized gas. This gas can be compressed air, or ''instrument air,'' provided by an electrically powered air compressor. In many situations across all segments of this industry, electricity is not available, and this energy is provided by pressurized natural gas (*i.e.,* ''natural gas-driven pneumatic pumps''). This energy can also be directly provided by electricity.

Natural gas-driven pneumatic pumps emit methane and VOC as part of their normal operation. These emissions occur when the gas used in the pump stroke is exhausted to enable liquid filling of the liquid cavity of the pump. Emissions are a function of the amount of fluid pumped, the pressure of the pneumatic supply gas, the number of pressure ratios between the pneumatic supply gas pressure and the fluid discharge pressure, and the mechanical inefficiency of the pump.

The 2021 U.S. GHGI estimates almost 215,000 metric tpy of methane emissions from pneumatic pumps in the oil and natural gas production segment in 2019. Specifically, this includes almost 113,000 metric tpy from natural gas production, 75,000 from petroleum production, and 26,000 from gathering and boosting compressor stations. These emissions make up 5 percent of all methane emissions in the GHGI for the combined gas and oil production segment, and 2 percent of all methane emissions for gathering and boosting. The overall total, which represents 3 percent of the total methane emissions from this industry, does not include emissions from the processing, transmission, and storage segments which the EPA is now proposing to regulate under NSPS OOOOb.

c. 2021 BSER Analysis

BSER was evaluated for all segments of the industry. The 2015 NSPS OOOOa proposal included methane and VOC standards for pneumatic pumps in the production and transmission and storage segments. However, the EPA did not finalize regulations for pneumatic pumps at gathering and boosting stations in the final 2016 NSPS OOOOa due to lack of data on the prevalence of the use of pneumatic pumps at gathering and boosting stations. Since that time, GHGRP subpart W has required that emissions from natural gas-driven pneumatic pumps be reported from gathering and boosting stations. As reported above, the 2021 GHGI estimates over 26,000 metric tpy of methane emissions from these pumps in the gathering and boosting segment in 2019. Similarly, the EPA did not include pneumatic pumps in the transmission and storage segment in the final 2016 NSPS OOOOa because we did not have a reliable source of information indicating the prevalence of pneumatic pumps or their emission rates in the transmission and storage segment. While the GHGI does not include emissions from pneumatic pumps in the transmission and storage segment, and the GHGRP does not require the reporting of emissions from these pumps in this segment, State rules (notably the California rule and the proposed New Mexico rule) do include requirements for natural gas driven pneumatic pumps at transmission and storage facilities. The EPA is soliciting comment on whether natural gas driven pneumatic pumps are used in the natural gas transmission and storage segment and to what extent.

In 2015, the EPA identified several options for reducing methane and VOC emissions from natural gas-driven pumps in the production and natural gas transmission and storage segments: Replace natural gas-driven pumps with instrument air pumps, replace natural gas-driven pumps with solar-powered direct current pumps (solar pumps), replace natural gas-driven pumps with electric pumps, route natural gas-driven pump emissions to a control device, and route natural gas-driven pump emissions to a process. The only option identified in 2015 and analyzed at natural gas processing plants was the use of instrument air. The EPA re-evaluated that information as well as new information including updated GHGI and GHGRP information, as well as information from more recent State regulations. No additional options were identified at this time. Therefore, for this analysis for the NSPS, the EPA re-evaluated these options as BSER. In the discussion below, the options to require technology that would eliminate methane and VOC emissions by requiring the use of a non-natural gas driven pumps are discussed, followed by a discussion of routing natural gas driven pumps to a control device.

With the exception of the evaluation of instrument air systems, the BSER analysis for pneumatic pumps was conducted on an individual pump basis. Due to the differences in the level of emissions, we conducted the BSER analysis separately for natural gas-driven diaphragm pneumatic pumps and natural gas-driven piston pneumatic pumps for the production and transmission and storage segments. The emission factor for diaphragm pneumatic pumps is 3.46 tpy of methane, while it is only 0.38 tpy of methane for piston pumps. The corresponding VOC emission factors are 0.96 tpy for the production segment and 0.096 tpy for the transmission and storage segment for diaphragm pumps, and 0.11 and 0.01 tpy for piston pumps, for production and transmission and storage segment, respectively.

For instrument air systems, the BSER analysis was conducted using model plants that included combinations of diaphragm and piston pumps. For example, the smallest model plant included two diaphragm pumps and two piston pumps. Therefore, the cost effectiveness calculated for these instrument air systems represents the cost to eliminate emissions from both types of pumps. Since instrument air was the only option evaluated for natural gas processing plants, the BSER determination was made for all pumps at the plants (as opposed to separate determinations for diaphragm and piston pumps).

Zero Emissions Options

For this analysis, we first evaluated the options that would eliminate methane and VOC emissions from pneumatic pumps, specifically instrument/compressed air systems, electric pumps, and solar-powered pumps.

Instrument air systems require a compressor, power source, dehydrator, and volume tank. No alterations are needed to the pump itself to convert from using natural gas to instrument air. However, they can only be utilized in locations with sufficient electrical power. Instrument air systems are more economical and, therefore, more common at facilities with a high concentration of pneumatic devices and where an operator can ensure the system is properly functioning. Electric pumps provide the same functionality as gas-driven pumps and are only restricted by the availability of a source of electricity.

Solar-powered pumps are a type of electric pump, except that the power is provided by solar-charged direct current (DC). Solar-powered pumps can be used at remote sites where a source of electricity is not available, and they have been shown to be able to handle a range of throughputs up to 100 gallons per day with maximum injection pressure around 3,000 pounds per square inch gauge (psig).

Production and Transmission and Storage Segments. For the production and transmission and storage segments, we evaluated the costs and impacts of these ''zero-emissions'' options (See Chapter 9 of the NSPS OOOOb and EG TSD for this rulemaking). 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 assumes that electricity is available onsite. As noted above, in 2015, the EPA determined that a zero-emission standard for pumps in the production and transmission and storage segments was infeasible because (1) electricity is not available at all sites and (2) solar pumps are not technically feasible in all situations for which piston pumps and diaphragm pumps are needed. 80 FR 56625–56626. While we specifically requested comment on this determination in 2015, nothing was submitted at that time that caused a reversal in this decision. At this time, we are unclear as to whether these limitations have been overcome and whether zero-emission pneumatic pumps are technically feasible for all pneumatic pumps throughout the production and transmission and storage segments. Therefore, at this time, we are unable to conclude that this zero-emission option represents BSER in this proposal, but we are soliciting comment on this issue to better understand whether a zero-emission option is now technically feasible.

As explained in Section XII.C.1.e, the EPA believes that similar previously identified technical limitations have been overcome in the context of pneumatic controllers. Further, a few States do prohibit emissions from pneumatic pumps throughout the Crude Oil and Natural Gas Industry. California prohibits the venting of natural gas to the atmosphere from pneumatic pumps through the use of compressed air or electricity, or by collecting all potentially vented natural gas with the use of a vapor collection system that undergoes periodic leak detection and repair. While California requires this, the fact that other States (*e.g.,* Colorado, Wyoming) do not require zero emissions from pneumatic pumps at all locations leads us to be uncertain as to whether it is technically feasible at this time. Canadian Provinces also regulate emissions from natural gas-driven pneumatic pumps. In British Columbia, pneumatic pumps installed after January 1, 2021, must not emit natural gas, and in Alberta, vent gas from pneumatic pumps installed after January 2, 2022, must be prevented. In addition, New Mexico has proposed a regulation that requires zero-emitting pumps, but only at production and transmission and storage sites that have access to electricity.

The EPA is soliciting comment on the basis for our proposed determination: That because electricity is not available at all sites and that there are applications at these sites where solar-powered pumps may not be feasible the Agency is uncertain as to whether the zero-emission options represent BSER. Also, as noted above, we are soliciting comment on an approach where the EPA would propose to subcategorize pneumatic pumps located in the production and transmission and storage sites based on availability of electricity and develop separate standards for each subcategory.

Natural gas processing plants. Natural gas processing plants are known to have a source of electrical power. Therefore, instrument air and electric pumps are technically feasible options at these facilities.

As the next step in the BSER determination, we evaluated capital and annual costs of compressed air systems for the natural gas processing plants. While electric pumps are an option at natural gas processing plants, we assumed that natural gas processing plants will elect to always use instrument air and an impacts analysis for electric pumps was not conducted.

The capital costs for an instrument air system were estimated to range from $4,500 to $39,500. The annual costs include the capital recovery cost (calculated at a 7 percent interest rate for 10 years), labor costs for operations and maintenance, and electricity costs. These are estimated to range from $11,300 to $81,350. Because gas emissions are avoided as compared to the use of natural gas-driven pumps, the use of an instrument air system will have natural gas savings realized from the gas not released. The EPA estimates that each diaphragm pump replaced will save 201 Mcf per year of natural gas from being emitted and each piston pump will save of 22 Mcf per year in the processing segment. The estimated value of the natural gas saved, based on $3.13 per Mcf, would range from $1,400 to $35,000 per year per plant. The annual costs, including these savings, ranges from $9,900 to $46,500. More information on this cost analysis is available in the NSPS OOOOb and EG TSD for this proposal.

The resulting cost effectiveness, under the single pollutant approach where all the costs are assigned to the reduction of one pollutant, for the application of instrument air to achieve a 100 percent emission reduction at natural gas processing plants ranges from $420 to $1,470 per ton of methane eliminated. For VOC, these cost effectiveness values ranged from $1,520 to $5,290 per ton of VOC eliminated. Considering savings, these cost effectiveness values range from $240 to $1,300 per ton of methane eliminated and $870 to $4,600 per ton of VOC eliminated. Under the multipollutant approach where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness ranges from $210 to $730 per ton of methane eliminated and $760 to $2,640 per ton of VOC eliminated. Considering savings, the cost effectiveness values range from $120 to $650 per ton of methane eliminated and from $440 to $2,320 per ton of VOC eliminated. These values are well within the range of what the EPA considers to be reasonable for methane and VOC using both the single pollutant and multipollutant approaches. As discussed above, the evaluation for instrument air systems is based on a combination of diaphragm and piston pumps. Therefore, this determination of reasonableness applies to both types of pumps at natural gas processing plants.

The 2016 NSPS OOOOa requires a natural gas emission rate of zero for pneumatic pumps at natural gas processing plants. Natural gas processing plants have successfully met this standard. Further, as discussed above several State agencies have rules that include this zero-emission requirement. This is a demonstration of the reasonableness of a natural gas emission rate of zero for pneumatic pumps at natural gas processing plants.

Secondary impacts from the use of instrument air systems are indirect, variable, and dependent on the electrical supply used to power the compressor. These impacts are expected to be minimal, and 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 gas processing plants is a natural gas 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 a natural gas emission rate of zero for all pneumatic pumps at natural gas processing plants.

Routing to a Control Device or VRU Options

Above we stated our determination that the EPA is unable to conclude that this zero-emission option represents BSER in this proposal for pumps in the production and transmission and storage segments. Therefore, we evaluated the use of control devices to reduce methane and VOC emissions. This BSER analysis was conducted on an individual pump basis and diaphragm and piston pumps were evaluated separately.

Combustors (*e.g.,* enclosed combustion devices, thermal oxidizers and flares that use a high-temperature oxidation process) can be used to control emissions from natural gas-driven pumps. Combustors are used to control VOCs in many industrial settings, since the combustor can normally handle fluctuations in concentration, flow rate, heating value, and inert species content. The types of combustors installed in the Crude Oil and Natural Gas Industry can achieve at least a 95 percent control efficiency on a continuous basis. It is noted that combustion devices can be designed to meet 98 percent control efficiencies, and can control, on average, emissions by 98 percent or more in practice when properly operated. However, combustion devices that are designed to meet a 98 percent control efficiency may not continuously meet this efficiency in practice in the oil and gas industry due to factors such as variability of field conditions.

A related option for controlling emissions from pneumatic pumps is to route vapors from the pump to a process, such as back to the inlet line of a separator, to a sales gas line, or to some other line carrying hydrocarbon fluids for beneficial use, such as use as a fuel. Use of a VRU has the potential to reduce the VOC and methane emissions from natural gas-driven pneumatic pumps by 100 percent if all vapor is recovered. However, the effectiveness of the gas capture system and downtime for maintenance would reduce capture efficiency and therefore, we estimate that routing emissions from a natural gas-driven pump to a VRU and to a process can reduce the gas emitted by approximately 95 percent, while at the same time, capturing the gas for beneficial use.

Based on a 95 percent reduction, the reduction in emissions in the production segment would be 3.29 tpy of methane and 0.91 tpy of VOC per diaphragm pump, and 0.36 tpy methane and 0.10 tpy VOC per piston pump. In the transmission and storage segment, the reduction in emissions would be 3.29 tpy of methane and 0.09 tpy of VOC per diaphragm pump, and 0.36 tpy of methane and 0.01 ton per year of VOC per piston pump.

Installation of a new combustion device or VRU. Costs for the installation of a new combustion device and a new VRU were evaluated. Installing a new combustion device has associated capital costs and operating costs. Based on the analysis conducted for the 2012 NSPS for a combustion device to control emissions from storage vessels, the capital cost for installing a new combustion device was $32,300 in 2008 dollars. We updated this to $38,500 to reflect 2019 dollars. Based on the life expectancy for a combustion device at 10 years, we estimate the annualized capital cost of installing a new combustion device to be $5,500 in 2019 dollars, using a 7 percent discount rate. The 2016 NSPS OOOOa TSD indicates the annual operating costs associated with a new combustion device were $17,000 in 2012 dollars, which we updated to $19,100 in 2019 dollars. Therefore, the total annual costs for a new combustion device are $24,600. Because the gas captured is combusted there are no gas savings associated with the use of a combustion device.

Installing a new VRU would also have both capital costs and maintenance costs. We based the costs of a VRU on the analysis conducted for the 2012 NSPS for control of emissions from storage vessels, which is representative of the costs that would be incurred for a VRU used to reduce emissions from natural gas-driven pneumatic pumps. The capital cost and installation costs for a new VRU are estimated to be $116,900 (in 2019 dollars) and the annual operation and maintenance costs estimated to be $11,200 (in 2019 dollars). The total annualized cost of a new VRU is estimated to be $27,800, including the operation and maintenance cost and the annualized capital costs based on a 7 percent discount rate and 10-year equipment life.

Because there is potential for beneficial use of gas recovered through the VRU, the savings that would be realized for 95 percent of the gas that would have emitted and lost were estimated. The gas saved would equate to 191 Mcf per year from a diaphragm pump and 21 Mcf per year from a piston pump. This results in estimated annual savings of $600 per diaphragm pump and $65 per piston pump in the production segment. The resulting annual costs, considering these savings, are $27,200 per diaphragm pump and $27,700 per piston pump in the production segment. Transmission and storage facilities do not own the natural gas; therefore, savings from reducing the amount of natural gas emitted/lost was not applied for this segment. More information on these cost analyses is available in the NSPS OOOOb and EG TSD for this proposal.

The resulting cost effectiveness estimates for application of a new control device to reduce emissions from natural gas-driven pumps in the production segment by 95 percent, or the use of a VRU to route emissions back to a process, are discussed below under both the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, and the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction. The results are presented separately for diaphragm and piston pumps. These values assume that the control device or VRU is installed solely for the purpose of controlling the emissions from a single natural gas-driven pneumatic pump, and only the emission reductions from a single pump are considered.

For diaphragm pumps in the production segment using the single pollutant approach, the cost effectiveness is estimated to be $7,500 per ton of methane reduced using a new combustion device, and $8,500 using a new VRU ($8,300 with savings). For VOC, these cost effectiveness values are $26,900 per ton of VOC reduced using a new combustion device, and $30,400 using a new VRU ($29,800 with savings). These values are outside of the range considered reasonable by the EPA for both methane and VOC.

For diaphragm pumps in the production segment using the multipollutant approach, the cost effectiveness is estimated to be $3,750 per ton of methane reduced using a new combustion device, and $4,250 using a new VRU ($4,150 with savings). For VOC, these cost effectiveness values are $13,450 per ton of VOC reduced using a new combustion device, and $15,200 using a new VRU ($14,900 with savings). These values are outside of the range considered reasonable by the EPA for both methane and VOC.

For piston pumps in the production segment using the single pollutant approach, the cost effectiveness is estimated to be $68,100 per ton of methane reduced using a combustion device, and $77,000 using a VRU ($76,800 with savings). For VOC, these cost effectiveness values are $244,800 per ton of VOC reduced using a combustion device, and $277,000 using a VRU ($276,400 with savings). These values are outside of the range considered reasonable by the EPA for both methane and VOC.

For piston pumps in the production segment using the multipollutant approach, the cost effectiveness is estimated to be $34,000 per ton of methane reduced using a combustion device, and $38,500 using a VRU ($38,400 with savings). For VOC, these cost effectiveness values are $122,400 per ton of VOC reduced using a combustion device, and $138,500 using a VRU ($138,200 with savings). These values are outside of the range considered reasonable by the EPA for both methane and VOC.

For diaphragm pumps in the transmission and storage segment using the single pollutant approach, the cost effectiveness is estimated to be $7,400 per ton of methane reduced using a new combustion device, and $8,500 using a new VRU. For VOC, these cost effectiveness values are $270,000 per ton of VOC reduced using a new combustion device, and $305,000 using a new VRU. These values are outside of the range considered reasonable by the EPA for both methane and VOC.

For diaphragm pumps in the transmission and storage segment using the multipollutant approach, the cost effectiveness is estimated to be $3,700 per ton of methane reduced using a new combustion device, and $4,200 using a new VRU. For VOC, these cost effectiveness values are $135,000 per ton of VOC reduced using a new combustion device, and $152,600 using a new VRU. These values are outside of the range considered reasonable by the EPA for both methane and VOC.

For piston pumps in the transmission and storage segment using the single pollutant approach, the cost effectiveness is estimated to be $68,000 per ton of methane reduced using a combustion device, and $77,000 using a VRU. For VOC, these cost effectiveness values are $2.5 million per ton of VOC reduced using a combustion device, and $2.8 million using a VRU. These values are outside of the range considered reasonable by the EPA for both methane and VOC.

For piston pumps in the transmission and storage segment using the multipollutant approach, the cost effectiveness is estimated to be $34,000 per ton of methane reduced using a combustion device, and $38,500 using a VRU. For VOC, these cost effectiveness values are $1.2 million per ton of VOC reduced using a combustion device, and $1.4 million using a VRU. These values are outside of the range considered reasonable by the EPA for both methane and VOC.

For diaphragm pumps, we do not consider the costs to be reasonable to install a new control device, or a new VRU to route the emissions to a process, for the production and transmission and storage segments for methane or VOC emission reduction using either the single pollutant or multipollutant approach. Similarly, for piston pumps, we do not consider the costs to be reasonable under any scenario. Therefore, we are unable to conclude that requiring the installation of a new control device, or the installation of a new VRU to route emissions to a process, to achieve 95 percent reduction of methane and VOC emissions from natural gas-driven pumps for the production or transmission segments represents BSER in this proposal.

Routing to an existing combustion device or VRU. In addition to evaluating the installation of a new control device or new VRU installed solely for the purpose of reducing the emissions from a single natural gas-driven pneumatic pump, we evaluated the option of routing the emissions from natural gas-driven pneumatic pumps to an existing control device to achieve a 95 percent reduction in methane and VOC emissions or routing the emissions to an existing VRU and to a process. The emission reduction for this option would be the same as discussed above for a new control device achieving 95 percent control, that is 3.29 tpy of methane and 0.91 tpy of VOC per diaphragm pump, and 0.36 tpy methane and 0.10 tpy VOC per piston pump in the production segment and 3.29 tpy of methane and 0.09 tpy of VOC per diaphragm pump, and 0.36 tpy of methane and 0.01 ton per year of VOC per piston pump in the transmission and storage segment. The resulting cost effectiveness estimates for use of an existing control device to reduce emissions from natural gas-driven pumps in the production segment by 95 percent, or the use of an existing VRU to route emissions to a process, are discussed below under both the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, and the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction. The results are presented separately for diaphragm and piston pumps.

We estimated the costs for routing emissions to an existing control device or VRU based on the average of the cost presented in the 2015 proposed NSPS OOOOa and the costs presented by two commenters to the proposal,[295] as documented in the 2016 NSPS OOOOa TSD. This yielded a capital cost estimate of $6,100 in 2019 dollars, for an annualized cost of $900 in 2019 dollars, using the 7 percent discount rate and 10-year equipment life. In the 2016 NSPS OOOOa TSD the EPA assumed there were no incremental operating costs for routing to an existing control device or VRU, so the total annual costs consist only of the $900 capital recovery cost. This assumption is maintained for this analysis. The same savings discussed above for the gas that is recovered by a VRU would be realized when routing to an existing VRU and to a process. These savings are $600 per year per diaphragm pump and $65 per year per piston pump in the production segment. The resulting annual costs for routing to an existing VRU and to process, considering these savings, are $270 per diaphragm pump and $800 per piston pump in the production segment. As noted above, transmission and storage facilities do not own the natural gas; therefore, savings from reducing the amount of natural gas emitted/lost was not applied for this segment.

For diaphragm pumps in the production segment using the single pollutant approach, the cost effectiveness is estimated to be $260 per ton of methane reduced using an existing combustion device, and $260 per ton of methane using an existing VRU ($80 with savings). For VOC, these cost effectiveness values are $950 per ton of VOC reduced using an existing combustion device, and $950 using an existing VRU ($300 with savings). For diaphragm pumps in the production segment using the multipollutant approach, the cost effectiveness is estimated to be $130 per ton of methane reduced using an existing combustion device, and $130 using an existing VRU ($40 with savings). For VOC, these cost effectiveness values are $475 per ton of VOC reduced using an existing combustion device, and $475 using an existing VRU ($150 with savings). These values are well within the range of what the EPA considers to be reasonable for methane and VOC using both the single pollutant and multipollutant approaches.

For diaphragm pumps in the transmission and storage segment using the single pollutant approach, the cost effectiveness is estimated to be $260 per ton of methane reduced using an existing combustion device, and $260 using an existing VRU. For VOC, these

[295] EPA–HQ–OAR–2010–0505–6884–A1 and EPA–HQ–OAR–2010–0505–6881.

cost effectiveness values are $9,500 per ton of VOC reduced using an existing combustion device, and $9,500 using an existing VRU. For diaphragm pumps in the transmission and storage segment using the multipollutant approach, the cost effectiveness is estimated to be $130 per ton of methane reduced using an existing combustion device, and $130 using an existing VRU. For VOC, these cost effectiveness values are $4,800 per ton of VOC reduced using an existing combustion device, and $4,800 using an existing VRU. These values are within the range of what the EPA considers to be reasonable.

The 2016 NSPS OOOOa requires that emissions from natural gas driven pneumatic pumps at well sites achieve a 95 percent reduction in methane and VOC emissions by routing them to a control device if an existing control device is on site. Owners and operators at well sites have successfully met this standard. Further, several State agencies (*e.g.,* California, proposed in New Mexico) have rules that include this requirement, and have extended the requirement to sites throughout the production segment as well as the transmission and storage segment. These factors considered together demonstrate the reasonableness of a requirement that emissions from natural gas driven pneumatic pumps at sites without access to electricity achieve a 95 percent reduction in methane and VOC emissions by routing them to a control device, provided that an existing control device is on site.

There are secondary impacts from the use of a combustion device to control emissions routed from natural gas-driven diaphragm pumps. The combustion of the recovered natural gas creates secondary emissions of hydrocarbons, NO_X, CO_2, and CO. The EPA considers the magnitude of these emissions to be reasonable given the significant reduction in methane and VOC emissions that the control would achieve. Details of these impacts are provided in the NSPS OOOOb and EG TSD for this rulemaking. There are no other wastes created or wastewater generated. The secondary impacts from use of a VRU are indirect, variable, and dependent on the electrical supply used to power the VRU. 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 diaphragm pumps in the production and transmission and storage segments is to route the emissions to an existing control device that achieves 95 percent control of methane and VOC, or to route the emissions to an existing VRU and to a process. We are, therefore, proposing to include this requirement in NSPS OOOOb.

For piston pumps in the production segment using the single pollutant approach, the cost effectiveness is estimated to be $2,400 per ton of methane reduced using a combustion device, and $2,400 using a VRU ($2,200 with savings). For VOC, these cost effectiveness values are $8,700 per ton of VOC reduced using a combustion device, and $8,700 using a VRU ($8,000 with savings).

For piston pumps in the production segment using the multipollutant approach, the cost effectiveness is estimated to be $1,200 per ton of methane reduced using a combustion device, and $1,200 using a VRU ($1,100 with savings). For VOC, these cost effectiveness values are $4,350 per ton of VOC reduced using a combustion device, and $4,350 using a VRU ($4,000 with savings).

For piston pumps in the production segment, we do not consider the costs to route emissions from a natural gas-driven pneumatic pump to an existing control device to achieve 95 percent reduction, or to route to an existing VRU and to a process, to be reasonable for methane or VOC using the single pollutant approach. However, the methane and VOC cost effectiveness using the multipollutant method is within the range that the EPA considers reasonable.

There are secondary impacts from the use of a combustion device to control emissions routed from natural gas-driven piston pumps. These impacts are the same as discussed above for diaphragm pumps.

In light of the above, we find that the BSER for reducing methane and VOC emissions from natural gas-driven piston pumps in the production and transmission and storage segments is to route the emissions to an existing control device that achieves 95 percent control of methane and VOC, or to route the emissions to an existing VRU and to a process. We are, therefore, proposing to include this requirement for piston pumps in NSPS OOOOb.

The EPA notes that State rules for concerning natural gas-driven piston pumps emissions control requirements differ. For example, California specifically includes both diaphragm and piston pumps in the definition of pneumatic pumps, while Colorado specifically excludes piston pumps from control requirements. At this time, the EPA is unable to fully understand the basis for the piston pump State control requirement differences based on the background information for these State rules.

We are specifically seeking comment on the emissions factors used to estimate the baseline emissions from pneumatic pumps, which are from a 1996 EPA/GRI study.[296] The EPA is interested in more recent information regarding emissions from pneumatic pumps.

For piston pumps in the transmission and storage segment using the single pollutant approach, the cost effectiveness is estimated to be $2,400 per ton of methane reduced using a combustion device, and $2,400 using a VRU. For VOC, these cost effectiveness values are $87,000 per ton of VOC reduced using a combustion device, and $87,000 using a VRU.

For piston pumps in the transmission and storage segment using the multipollutant approach, the cost effectiveness is estimated to be $1,200 per ton of methane reduced using a combustion device, and $1,200 using a VRU. For VOC, these cost effectiveness values are $43,500 per ton of VOC reduced using a combustion device, and $43,500 using a VRU.

For piston pumps in the transmission and storage segment, we do not consider the costs to be reasonable to route emissions from a natural gas-driven pneumatic pump to an existing control device, or to route to an existing VRU and to a process, for either methane or VOC under the single pollutant approach. Further, we do not find that the cost effectiveness for both methane and VOC to be reasonable under the multipollutant approach. Therefore, we are unable to conclude that requiring the routing of emissions from natural gas-driven piston pumps in the transmission and storage segment to an existing control device to achieve 95 percent reduction of methane and VOC emissions, or the routing of emissions to a VRU and to a process, represents BSER for NSPS OOOOb in this proposal.

2. EG OOOOc

The EPA evaluated BSER for the control of methane from existing pneumatic pumps (designated facilities) in all segments in the Crude Oil and Natural Gas source category covered by the proposed NSPS OOOOb and translated the degree of emission limitation achievable through application of the BSER into a proposed presumptive standard for these facilities

[296] Gas Research Institute (GRI)/U.S. Environmental Protection Agency. 1996d. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps.* June 1996 (EPA–600/R–96–080m).

that mirrors the proposed NSPS OOOOb, with the exception of the BSER conclusion regarding piston pumps in the production segment.

First, based on the same criteria and reasoning explained above the EPA is proposing to define the designated facility in the context of existing pneumatic pumps as those that commenced construction on or before November 15, 2021. Based on information available to the EPA, we did not identify any factors specific to existing sources that would indicate that the EPA should alter this definition as applied to existing sources.

The EPA finds that the controls evaluated for new sources for NSPS OOOOb are appropriate for consideration for existing sources under the EG OOOOc. The EPA finds no reason to evaluate different, or additional, control measures in the context of existing sources because the EPA is unaware of any control measures, or systems of emission reduction, for pneumatic pumps that could be used for existing sources but not for new sources. Next, the methane emission reductions expected to be achieved via application of the control measures identified above to new sources are also expected to be achieved by application of the same control measures to existing sources. The EPA finds no reason to believe that these calculations would differ for existing sources as compared to new sources because the EPA believes that the baseline emissions of an uncontrolled source are the same, or very similar, and the efficiency of the control measures are the same, or very similar, compared to the analysis above. This is also true with respect to the costs, non-air environmental impacts, energy impacts, and technical limitations discussed above for the control options identified.

The EPA has not identified any costs associated with applying these controls at existing sources, such as retrofit costs, that would apply any differently than, or in addition to, those costs assessed above regarding application of the identified controls to new sources. The cost effectiveness values for the option of zero emissions from pneumatic pumps in the natural gas processing sector range from $420 to $1,470 per ton of methane eliminated ($240 to $1,300 per ton considering savings). These cost effectiveness values are in the range considered reasonable by the EPA. However, as explained above in the context of new sources, at this time we are unclear as to whether the technical limitations associated with this option have been overcome and whether zero-emission pneumatic pumps are technically feasible. Therefore, at this time, we are unable to conclude that this zero-emission option represents BSER in this proposal for the EG, but we are soliciting comment on this issue to better understand whether a zero-emission option is technically feasible.

For diaphragm pumps in the production segment the cost effectiveness is estimated to be $260 per ton of methane reduced using an existing (on site) combustion device or VRU, and $260 per ton of methane using an existing (on site) VRU ($80 with savings). For diaphragm pumps in the transmission and storage segment the cost effectiveness of is estimated to be $260 per ton of methane reduced using an existing (on site) combustion device, and $260 using an existing (on site) VRU. This cost effectiveness is considered reasonable by the EPA.

For piston pumps in the production segment the cost effectiveness is estimated to be $2,400 per ton of methane reduced using an existing (on site) combustion device or VRU, and $2,400 per ton of methane using an existing (on site) VRU ($2,200 with savings). For piston pumps in the transmission and storage segment the cost effectiveness is estimated to be $2,400 per ton of methane reduced using an existing (on site) combustion device, and $2,400 using an existing (on site) VRU. This cost effectiveness is outside of the range considered reasonable by the EPA. In summary, the EPA did not identify any factors specific to existing sources, as opposed to new sources, that would alter the analysis above for the proposed NSPS OOOOb as applied to the designated pollutant (methane) and the designated facilities (pneumatic pumps). However, the BSER conclusion regarding piston pumps in the production and transmission and storage segments for the EG differs from the conclusion for new sources under the NSPS. As a result, the proposed presumptive standards for existing pneumatic pumps are as follows.

For diaphragm pneumatic pumps in the production and transmission and storage segments, the presumptive standard is routing emissions to an existing (already on site) control device or existing (already on site) VRU and to a process to achieve 95 percent reduction in methane. For pneumatic pumps (diaphragm and piston) in the natural gas processing sector, the presumptive standard is a natural gas emission rate of zero.

As for new sources, the EPA is specifically soliciting comment on whether the production and transmission storage segments should be subcategorized based on the availability of electricity and BSER determined separately for each subcategory in the EG.

H. Proposed Standards for Equipment Leaks at Natural Gas Processing Plants

1. NSPS OOOOb

a. Background

In the 2012 NSPS OOOO, the EPA established VOC standards for equipment leaks at onshore natural gas processing plants. These standards were based on the Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (NSPS VVa), which is an EPA Method 21 LDAR program generally requiring monthly monitoring of pumps with a leak definition of 2,000 ppm, quarterly monitoring of valves with a leak definition of 500 ppm, and annual monitoring of connectors with a leak definition of 500 ppm.[297] In the 2016 NSPS OOOOa, the EPA added GHG (methane) to the title of the standards for equipment leaks at onshore natural gas plants but continued to rely on the requirements in NSPS VVa, which limited monitoring and repair (if found leaking) to those equipment components ''in VOC service.'' Based on our review of the current standards, we are proposing to revise the equipment leak standards for onshore natural gas plants to more readily apply to equipment components that have the potential to emit methane even though they are not ''in VOC service.''

b. Technology and LDAR Program Review

The EPA acknowledges that advancements are being made in leak detection, including remote sensing, sensor networks, and OGI. The EPA already provides use of OGI as an alternative work practice at 40 CFR 60.18(g); however, the alternative work practice requires annual EPA Method 21 monitoring as part of the OGI monitoring protocol. Parallel with this proposal, the EPA is proposing appendix K to part 60 to provide a standard method for OGI leak monitoring. This allows us to consider a wider range of LDAR programs when evaluating the BSER for equipment leaks at onshore natural gas processing plants. To evaluate different LDAR programs, we used a Monte Carlo simulation that simulated initiation of leaks for pumps, valves, and connectors at monthly intervals based on

[297] 40 CFR part 60, subpart VVa, includes ''skip period'' provisions that may alter the cited monitoring frequencies.

component specific leak frequencies and EPA Method 21 leak size distributions based on historical EPA Method 21 leak data. We randomly assigned a mass emission rate based on the EPA Method 21 leak size assuming a lognormal distribution for the mass emission rate around the EPA Method 21 screening value correlation equation estimates. The simulation runs for five years for each LDAR program to build up leaks that might not be repaired under a given program, and compares the emissions estimated in the fifth year of the simulation for different LDAR programs. The model also records the number of repairs made in the fifth year of the simulation to assess the annual repair costs associated with the LDAR program. More information on the LDAR program Monte Carlo simulation and associated cost analyses is available in the NSPS OOOOb and EG TSD for this proposal.

Based on our model simulation of NSPS OOOOa requirements (Method 21 based LDAR program following the requirements in NSPS VVa), the EPA projects that the program achieves a 91.5 percent emission reduction for the components monitored. This is comparable to the projected control efficiencies of this LDAR program applied to similar industrial processes.[298] However, when considering the components not monitored at the onshore natural gas processing plant because they are not ''in VOC service'', the overall hydrocarbon control efficiency of the current NSPS OOOOa requirements drops to 73.2 percent. Thus, significant emission reductions can be achieved by extending the current provisions to include all components that have the potential to emit methane.

Based on our model simulation of an OGI-based LDAR program, we found that bimonthly OGI monitoring of all equipment components (with potential VOC or methane emissions) using devices capable of identifying mass leaks at 30 g/hr and at 15 g/hr would achieve emission reductions of 88.5 percent and 92.2 percent, respectively. Based on the requirements in appendix K that the instrument be able to detect a methane leak of 17 g/hr, these results suggest that bimonthly OGI monitoring following appendix K will achieve comparable emission reductions as the current NSPS OOOOa requirements for the equipment components subject to the monitoring requirements.

c. Control Options and 2021 BSER Analysis

The EPA then evaluated various LDAR programs for their control efficiency, cost and cost effectiveness for a small and a large model natural gas processing plant. These ''small'' and ''large'' model plants were based on the number of components at each facility in various monitoring summaries for onshore natural gas processing plants.[299] We considered the (option 1) current NSPS OOOOa standards expanded to components that also have the potential to emit methane regardless of the VOC content of the stream, (option 2) bimonthly OGI following appendix K for all components (VOC or methane), and (options 3 and 4) a hybrid approach following the current alternative work practice (regular OGI with annual EPA Method 21). For option 3 we evaluated requiring quarterly OGI with an annual EPA Method 21 survey at 10,000 ppm. For option 4 we evaluated requiring bimonthly OGI with an annual EPA Method 21 survey at 10,000 ppm. These control options and their associated costs are summarized in Tables 18 and 19 for the small and large model plants, respectively.

TABLE 18—SUMMARY OF CONTROL OPTIONS AND COSTS FOR SMALL MODEL PLANTS

Control option	Emissions reduction (tpy)		Capital cost ($)	Annual cost ($/yr)	CE [a] ($/ton VOC)	CE [a] ($/ton methane)	Incremental ($/ton VOC)	Incremental ($/ton methane)
	VOC	Methane						
Methane and VOC Service								
1	12.34	56.95	$17,700	$114,100	$9,200	$2,000		
2	12.61	58.19	1,500	62,800	5,000	1,100	−189,100	−41,300
3	12.64	58.33	19,200	84,500	6,700	1,400	696,200	151,100
4	12.76	58.92	19,200	95,500	7,500	1,600	87,000	18,800

[a] Cost effectiveness (CE) compared to no monitoring.

TABLE 19—SUMMARY OF CONTROL OPTIONS AND COSTS FOR LARGE MODEL PLANTS

Control option	Emissions reduction (tpy)		Capital cost ($)	Annual cost ($/yr)	CE [a] ($/ton VOC)	CE [a] ($/ton methane)	Incremental ($/ton VOC)	Incremental ($/ton methane)
	VOC	Methane						
Methane and VOC Service								
1	25.59	118.27	$36,200	$229,000	$9,000	$1,900		
2	26.11	120.81	3,000	123,500	4,700	1,000	−200,000	−43,100
3	26.17	121.10	39,200	170,500	6,500	1,400	760,000	165,200
4	26.44	122.31	39,200	191,300	7,200	1,600	79,500	17,100

[a] Cost effectiveness (CE) compared to no monitoring.

We further assumed that all facilities outsource their equipment leak surveys. The first year ''capital'' costs of implementing an EPA Method 21 program (identifying components required to be monitored and developing a data system to track the proper frequency to monitor each component) are summarized in Tables 18 and 19. Additionally, these tables summarize the annualized costs of conducting a complete EPA Method 21

[298] EPA, October 2007. ''Leak Detection and Repair—A Best Practices Guide.'' Office of Enforcement and Compliance Assurance. EPA–305–D–07–001. See ''Table 4.1—Control effectiveness for an LDAR program at a chemical process unit and a refinery.''

[299] See Section 10.4 of Chapter 10 ''Equipment Leaks from Natural Gas Processing Plants'' in the TSD located at Docket ID No. EPA–HQ–OAR–2021–0317.

monitoring survey of all equipment (those in VOC service or contacting methane), which includes the annual costs of conducting required surveys and making the necessary repairs as well as annualized first year ''capital'' costs. The first-year startup costs for OGI surveys are small, estimated to be $750 for small plants and $1,500 for large plants. Because OGI surveys can be conducted much more quickly, the annualized cost of conducting bimonthly OGI surveys is approximately half the annualized cost of EPA Method 21 surveys through NSPS VVa. Both EPA Method 21 and OGI LDAR programs reduce loss of product. Therefore, the costs of the LDAR programs are offset to some degree to the emissions reduced. When evaluating LDAR programs that consider all components (both VOC and methane), the annual value of the product not lost due to reduced emissions is approximately $14,000/yr.

Based on our analysis, the resulting cost effectiveness is reasonable for all of the options when assigning all costs to the reduction of methane. When assigning all costs to VOC reduction, however, only the bimonthly OGI option is considered reasonable at $5,000/ton VOC reduced for small plants and $4,700/ton VOC reduced at large plants. The EPA next considered the incremental cost-effectiveness between the four options to determine which option represents the BSER for equipment leaks at onshore natural gas processing plants. All four options achieve similar emission reductions, as discussed in the previous section. Bimonthly OGI (option 2) reduces an additional 2 tpy of methane at a cost savings. Adding annual EPA Method 21 to bimonthly OGI monitoring (option 4) reduces an additional 1.5 tpy methane for large model gas plant but at significant cost well above any costs the EPA would consider appropriate, at approximately $45,000/ton methane reduced (comparing option 4 with option 2). Therefore, the EPA does not consider it reasonable to require the additional of annual EPA Method 21.

Based on the discussion above, we consider a bimonthly OGI LDAR program following appendix K that includes all equipment components that have the potential to emit VOC or methane to be BSER for new sources. Therefore, we are proposing this LDAR requirement for new sources under NSPS OOOOb. Because an EPA Method 21 monitoring program based on the requirements of NSPS VVa when applied to all equipment components that have the potential to emit VOC or methane is projected to achieve similar emission reductions, we are proposing that this EPA Method 21-based LDAR program may be used as an alternative to bimonthly OGI surveys.

In the development of the 2012 NSPS OOOO, we found that NSPS VVa provisions for PRDs, open-ended valves or lines, and closed vent systems and equipment designated with no detectable emissions were BSER. Available information since then continues to support this conclusion. Therefore, we are proposing to retain the current requirements in the 2016 NSPS OOOOa (which adopts by reference specific provisions NSPS VVa) for PRDs, open-ended valves or lines, and closed vent systems and equipment designated with no detectable emissions, except expanding the applicability to sources that have the potential to emit methane. The EPA is soliciting information that would support the use of the proposed bimonthly OGI monitoring requirement for these equipment components in place of the NSPS VVa annual EPA Method 21 monitoring.

The EPA requests comments 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. Based on our Monte Carlo equipment leak model that assumes well-implemented LDAR programs with no delayed repair, both an EPA Method 21 based program following NSPS VVa and a bimonthly OGI monitoring program following appendix K are projected to achieve a 91-percent emission reduction effectiveness. We request comment on whether providing such an emission reduction target and equipment leak modeling tool to simulate LDAR under similar ''ideal'' program implementation conditions may facilitate future equivalency determinations.

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 equipment components that have the potential to emit methane is approximately $850/ton methane reduced. As explained above, the cost effectiveness of this OGI monitoring option is within the range of costs we believe to be reasonable for methane reductions. Therefore, we consider a bimonthly OGI LDAR program following appendix K that includes all equipment components that have the potential to emit methane to be BSER for existing sources.

I. Proposed Standards for Well Completions

1. NSPS OOOOb

a. Background

Pursuant to CAA section 111(b)(1)(B), the EPA reviewed the current standards in NSPS OOOOa for well completions and proposes to determine that they continue to reflect the BSER for reducing methane and VOC emissions during oil and natural gas well completions following hydraulic fracturing and refracturing. Accordingly, we are not proposing revisions to these standards. Provided below are a description of the affected facilities, the current standards, and a summary of our review.

Natural gas and oil wells all must be ''completed'' after initial drilling in preparation for production. Well completion activities not only will vary across formations but can vary between wells in the same formation. Over time, completion and recompletion activities may change due to the evolution of well characteristics and technology advancement. Well completion activities include multiple steps after the well bore hole has reached the target depth. Developmental wells are drilled within known boundaries of a proven oil or gas field and are located near existing well sites where well parameters are already recorded and necessary surface equipment is in place. When drilling occurs in areas of new or unknown potential, well parameters such as gas composition, flow rate, and temperature from the formation need to be ascertained before surface facilities required for production can be adequately sized and brought on site. In this instance, exploratory (also referred to as ''wildcat'') wells and field boundary delineation wells typically either vent or combust the flowback gas.

One completion step for improving oil and gas production is to fracture the reservoir rock with very high-pressure fluid, typically a water emulsion with a proppant (generally sand) that ''props open'' the fractures after fluid pressure is reduced. Natural gas emissions are a result of the backflow of the fracture fluids and reservoir gas at high pressure and velocity necessary to clean and lift excess proppant to the surface. Natural gas from the completion backflow escapes to the atmosphere during the reclamation of water, sand, and hydrocarbon liquids during the collection of the multi-phase mixture directed to a surface impoundment. As the fracture fluids are depleted, the backflow eventually contains a higher volume of natural gas from the formation. Due to the specific additional equipment and resources involved and the nature of the backflow of the fracture fluids, completions involving hydraulic fracturing have higher costs and vent substantially more natural gas than completions not involving hydraulic fracturing.

During its lifetime, wells may need supplementary maintenance, referred to as recompletions (these are also referred to as workovers). Recompletions are remedial operations required to maintain production or minimize the decline in production. Examples of the variety of recompletion activities include completion of a new producing zone, re-fracture of a previously fractured zone, removal of paraffin buildup, replacing rod breaks or tubing tears in the wellbore, and addressing a malfunctioning downhole pump. During a recompletion, portable equipment is conveyed back to the well site temporarily and some recompletions require the use of a service rig. As with well completions, recompletions are highly specialized activities, requiring special equipment, and are usually performed by well service contractors specializing in well maintenance. Any flowback event during a recompletion, such as after a hydraulic fracture, will result in emissions to the atmosphere unless the flowback gas is captured.

When hydraulic re-fracturing (recompletions) is performed, the emissions are essentially the same as new well completions involving hydraulic fracture, except that surface gas collection equipment will already be present at the wellhead after the initial fracture. The flowback velocity during re-fracturing will typically be too high for the normal wellhead equipment (separator, dehydrator, lease meter), while the production separator is not typically designed for separating sand.

Flowback emissions are a result of free gas being produced by the well during well cleanup event, when the well also happens to be producing liquids (mostly water) and sand. The high rate flowback, with intermittent slugs of water and sand along with free gas, is directed to an impoundment or vessels until the well is fully cleaned up, where the free gas vents to the atmosphere while the water and sand remain in the impoundment or vessels. Therefore, nearly all of the flowback emissions originate from the recompletion process but are vented as the flowback enters the impoundment or vessels. Minimal amounts of emissions are caused by the fluid (mostly water) held in the impoundment or vessels since very little gas is dissolved in the fluid when it enters the impoundment or vessels.

The 2021 GHGI estimates approximately 34,000 metric tpy of methane emissions from hydraulically fractured completion/workover natural gas well events and approximately 12,000 metric tpy of methane emissions from hydraulically fractured completion/workover oil well events in 2019.

b. Affected Facility

Each affected facility is a single well that conducts a well completion operation following hydraulic fracturing or refracturing.

c. Current NSPS Requirements

The current NSPS for natural gas and oil well completions and recompletions are the same. For well completions of hydraulically fractured (or refractured) wells, the EPA identified two subcategories of hydraulically fractured wells for which well completions are conducted: (1) Non-wildcat and non-delineation wells (subcategory 1 wells); and (2) wildcat and delineation wells and low-pressure wells (subcategory 2 wells). A wildcat well, also referred to as an exploratory well, is a well drilled outside known fields or is the first well drilled in an oil or gas field where no other oil and gas production exists. A delineation well is a well drilled to determine the boundary of a field or producing reservoir.

In the 2016 NSPS OOOOa rule, the EPA finalized operational standards for non-wildcat and non-delineation wells (subcategory 1 wells) that required a combination of REC and combustion. Because RECs are not feasible for every well at all times during completion or recompletion activities due to variability of produced gas pressure and/or inert gas concentrations, the rule allows for wellhead owners and operators to continue to reduce emissions when RECs are not feasible due to well characteristics (*e.g.,* wellhead pressure or inert gas concentrations) by using a completion combustion device. For wildcat and delineation wells and low-pressure wells (subcategory 2 wells), the EPA finalized an operational standard that required either (1) routing all flowback directly to a completion combustion device with a continuous pilot flame (which can include a pit flare) or, at the option of the operator, (2) routing the flowback to a well completion vessel and sending the flowback to a separator as soon as a separator will function and then directing the separated gas to a completion combustion device with a continuous pilot flame. For option 2, any gas in the flowback prior to the point when the separator will function was not subject to control. 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. Under the 2016 NSPS OOOOa rule, oil wells with a gas-to-oil ratio less than 300 scf of gas per stock tank barrel of oil produced are affected facilities but have no requirements other than to maintain records of the low GOR certification and a claim signed by the certifying official. As discussed in section X.B.1 of this preamble, in the 2020 Technical Rule, the EPA made certain amendments (*e.g.,* related to the use of a separator, amended definition of flowback, amended recordkeeping and reporting requirements) to the VOC standards for well completions in the 2016 NSPS OOOOa, and is proposing to apply the same amendments to the methane standards for well completions in the 2016 NSPS OOOOa.

d. 2021 BSER Analysis

The two techniques considered under the previous BSER analyses that have been proven to reduce emissions from production segment well completions and recompletions include REC and completion combustion. REC is an approach that not only reduces emissions but delivers natural gas product to the sales meter that would typically be vented. The second technique, completion combustion, destroys the organic compounds. No other emissions control techniques were identified as being required under other rules (Federal, State, or local rules) that would exceed the level of control required under the 2016 NSPS OOOOa rule. Therefore, no other technology control requirements were evaluated in this review.

Reduced emission completions, also referred to as ''green'' or ''flareless'' completions, use specially designed equipment at the well site to capture and treat gas so it can be directed to the sales line. This process prevents some natural gas from venting and results in additional economic benefit from the sale of captured gas and, if present, gas condensate. However, as the EPA has previously acknowledged, there are some limitations that may exist for performing RECs based on technical barriers. These limitations continue to exist. Three main limitations for performing a REC include the proximity of pipelines to the well, the pressure of the produced gas, and the inert gas concentration. These limitations are discussed below.

For exploratory wells (in particular), no nearby sales line may exist. The lack of a nearby sales line incurs higher capital outlay risk for exploration and production companies and/or pipeline companies constructing lines in exploratory fields. The EPA is soliciting comment on how ''access to a sales line'' and a ''sales line'' should be defined.

During the completion/recompletion process, the pressure of flowback fluids may not be sufficient to overcome the gathering line backpressure. In this case, combustion of flowback gas is one option, either for the duration of the flowback or until a point during flowback when the pressure increases to flow to the sales line. Another potential compressor application is to boost pressure of the flowback gas after it exits the separator. This technique is experimental because of the difficulty operating a compressor where there is a widely fluctuating flowback rate.

Lastly, if the concentration of inert gas, such as nitrogen or CO_2, in the flowback gas exceeds sales line concentration limits, venting to the atmosphere or to a combustion device of the flowback may be necessary for the duration of flowback or until the gas energy content increases to allow flow to the sales line. Further, since the energy content of the flowback gas may not be high enough to sustain a flame due to the presence of the inert gases, combustion of the flowback stream would require a continuous ignition source with its own separate fuel supply.

Where a REC can be conducted, the achievable emission reductions vary according to reservoir characteristics and other parameters including length of completion, number of fractured zones, pressure, gas composition, and fracturing technology/technique. Based on several experiences presented at Natural Gas STAR technology transfer workshops, this analysis assumes 90 percent of flowback gas can be recovered during a REC.[300] Gas that cannot be recovered during a REC can be directed to a completion combustion device in order to achieve an estimated 95 percent reduction in overall emissions.

Completion combustion devices commonly found on drilling sites are generally crude and portable, often installed horizontally due to the liquids that accompany the flowback gas. These flares can be as simple as a pipe with a basic ignition mechanism and discharge over a pit near the wellhead. However, the flow directed to a completion combustion device may or may not be combustible depending on the inert gas composition of flowback gas, which would require a continuous ignition source. Sometimes referred to as pit flares, these types of combustion devices do not employ an actual control device and are not capable of being tested or monitored for efficiency. They do provide a means of minimizing vented gas and is preferable to venting.

The efficiency of completion combustion devices, or exploration and production flares, can be expected to achieve 90 percent, on average, over the duration of the completion or recompletion.[301] If the energy content of natural gas is low, then the combustion mechanism can be extinguished by the flowback gas. Therefore, it is more reliable to install an igniter fueled by a consistent and continuous ignition source. Because of the exposed flame, open pit flaring can present a fire hazard or other undesirable impacts in some situations (*e.g.,* dry, windy conditions and proximity to residences). As a result, owners and operators may not be able to combust unrecoverable gas safely in every case.

Noise and heat are the two adverse impacts of completion combustion device operations. In addition, combustion and partial combustion of many pollutants also create secondary pollutants including NO_X, CO, sulfur oxides (SO_X), CO_2, and smoke/particulates. The degree of combustion depends on the rate and extent of fuel mixing with air and the temperature maintained by the flame. Most hydrocarbons with carbon-to-hydrogen ratios greater than 0.33 are likely to smoke. The high methane content of the gas stream routed to the completion combustion device, it suggests that there should not be smoke except in specific circumstances (*e.g.,* energized fractures). The stream to be combusted may also contain liquids and solids that will also affect the potential for smoke.

The previous BSER analyses cost effectiveness per ton of methane and VOC emissions reduced per completion event evaluated for REC, completion combustion, and REC and completion combustion were updated to 2019 dollars. The results of this updated analysis are provided below, and details are provided in the NSPS OOOOb and EG TSD for this rulemaking.

The updated capital cost for performing a REC for a well completion or recompletion lasting 3 days is estimated to be $15,174 (2019 dollars). Monetary savings associated with additional gas captured to the sales line is estimated based on a natural gas price of $3.13 per Mcf. It was assumed that all gas captured would be included as sales gas. The updated capital and cost for wells including completion combustion devices resulted in an estimated average completion combustion device cost of approximately of $4,198 per well completion (2019 dollars). For both REC and completion combustion devices, the capital costs are one-time events, and annual costs were conservatively assumed to be equal to the capital costs. The EPA also evaluated the costs that would be associated with using a combination of a REC and completion combustion device. The annual costs would be a combined estimated capital and annual cost of $19,371 (2019 dollars). As a result of updating capital/annual costs to reflect 2019 dollars and decreasing the control efficiency assumed for completion combustion from 95 percent to 90 percent, the cost effectiveness estimates are slightly higher, but substantially similar to previous cost effectiveness BSER analysis control option estimates for natural gas well and oil well completions and recompletions.

For gas wells, under the single pollutant approach where all the costs are assigned to the reduction of methane emissions and zero to reduction of VOC, the cost effectiveness estimates were approximately $1,180 per ton of methane reduced for REC ($990 with natural gas savings), $330 for completion combustion, and $1,420 for a combination of REC and completion combustion ($1,250 with natural gas savings). If all costs were assigned to VOC reduction and zero to methane reduction, the cost effectiveness estimates were approximately $4,230 per ton of VOC removed for REC ($3,570 with natural gas savings), $1,170 for completion combustion, and $5,110 for a combination of REC and completion combustion ($4,490 with natural gas savings). Under the multipollutant approach where half the cost of control is assigned to the methane reduction and half to the VOC reduction, these estimates are approximately $590 per ton of methane reduced for REC ($500 with natural gas savings), $160 for completion combustion, and $710 for a combination of REC and completion combustion ($630 with natural gas savings). For VOC, the cost effectiveness

[300] Memorandum to Bruce Moore, U.S. EPA from ICF Consulting. *Percent of Emissions Recovered by Reduced Emission Completions.* May 2011.

[301] 77 FR 48889–48890, March 22, 2013 (Approval and Promulgation of Federal Implementation Plan for Oil and Natural Gas Well Production Facilities; Fort Berthold Indian Reservation (Mandan, Hidatsa, and Arikara Nation), North Dakota; Rule).

estimates were approximately $2,100 per ton of VOC removed for REC ($1,790 with natural gas savings), $590 for completion combustion, and $2,600 for a combination of REC and completion combustion ($2,250 with natural gas savings).

For oil wells, under the single pollutant approach where all the costs are assigned to the reduction of methane emissions and zero to reduction of VOC emissions, the cost effectiveness values were approximately $1,620 per ton of methane reduced for REC ($1,440 with natural gas savings), $450 for completion combustion, and $1,960 for a combination of REC and completion combustion ($1,790 with natural gas savings). Where all costs were assigned to reducing VOC emissions and zero to reducing methane emissions, the cost effectiveness estimates were approximately $5,840 per ton of VOC removed for REC ($5,190 with natural gas savings), $1,620 for completion combustion, and $7,070 for a combination of REC and completion combustion ($6,450 with natural gas savings). Under the multipollutant approach where half the cost of control is assigned to the methane reduction and half to the VOC reduction, these estimates are approximately $810 per ton of methane reduced for REC ($720 with natural gas savings), $230 for completion combustion, and approximately $980 for a combination of REC and completion combustion ($900 with natural gas savings). For VOC, the cost effectiveness estimates were approximately $2,920 per ton of VOC removed for REC ($2,600 with natural gas savings), $810 for completion combustion, and $3,530 for a combination of REC and completion combustion ($3,220 with natural gas savings).

As noted above, the current NSPS OOOOa requirements consist of a combination of REC and completion combustion for hydraulically fractured natural gas and oil well completions. These techniques have been employed by the oil and gas industry since 2012 for natural gas well completions and 2016 for oil well completions. The EPA concludes that the cost effectiveness of REC, completion combustion, or a combination, for natural gas and oil wells are within the range that the EPA considers to be reasonable when considering both methane and VOC cost effectiveness. Since there are multiple scenarios where the cost effectiveness of the control measures is reasonable for natural gas and oil wells (including the cost effectiveness of VOC for REC and combined REC and completion combustion), we conclude that the overall cost effectiveness is reasonable.

There are secondary impacts from the use of a completion combustion device, as the combustion of the gas creates secondary emissions of hydrocarbons, NO_X, CO_2, and CO. The EPA considers the magnitude of these emissions to be reasonable given the significant reduction in methane and VOC emissions that the control would achieve. Details of these impacts are provided in the NSPS OOOOb and EG TSD for this rulemaking. There are no other wastes created or wastewater generated from either REC or completion combustion.

In light of the above, we determined that the current standards, which consist of a combination of REC and combustion, continue to represent the BSER for reducing methane and VOC emissions from well completions of hydraulically fractured or refractured oil and natural gas wells. We therefore propose to retain these standards in the proposed NSPS OOOOb.

As discussed in section XII.I.1.c, in the 2020 Technical Rule, the EPA made certain amendments to the VOC standards for well completions in the 2016 NSPS OOOOa. For the same reasons provided in the 2020 Technical Rule and discussed in section X.B.1 of this preamble for including these amendments for methane in NSPS OOOOa, the EPA is proposing to include these methane and VOC amendments for well completions in the NSPS OOOOb rule.

2. EG OOOOc

A well completion operation following hydraulic fracturing or refracturing is a ''modification,'' as defined in CAA section 111(a), as each such well completion operation involves a physical change to a well that results in an increase in emissions; accordingly, each such operation would trigger the applicability of the NSPS. Therefore, there are no ''existing'' well completion operations of hydraulically fractured or refractured oil or natural gas wells. In light of the above, there are no proposed presumptive standards for such operations in this action.

J. Proposed Standards for Oil Wells With Associated Gas

1. NSPS OOOOb

a. Background

Wells in some formations and shale basins are drilled primarily for oil production. Although the wells are drilled for oil, the wells may produce an associated, pressurized natural gas stream. The natural gas is either naturally occurring in a discrete gaseous phase within the liquid hydrocarbon or is released from the liquid hydrocarbons by separation. In many areas, a natural gas gathering infrastructure may be at capacity or unavailable. In such cases, if there is not another beneficial use of the gas at the site (*e.g.,* as fuel) the collected natural gas is either flared or vented directly to the atmosphere.

Emissions from associated gas venting and flaring are not regulated by either the 2012 NSPS OOOO or the NSPS OOOOa. The EPA did not evaluate BSER for associated gas production in either rulemaking. For this rulemaking, the EPA is proposing that methane and VOC emissions resulting from associated gas production be reduced by at least 95 percent.

b. Definition of Affected Facility

The EPA is proposing the definition of an oil well associated gas affected facility as an oil well that produces associated gas.

c. Description

In 2019, according to the EIA, the number of onshore gas producing oil wells in the U.S.[302] was 334,342 and the volume of vented and flared natural gas in 2019 was 523,066 million cubic feet.[303] According to the 2021 GHGI, in 2019 venting of associated gas emitted 42,051 metric tons of CH_4 and 1,291 metric tons of CO_2 and flaring of associated gas emitted 81,797 metric tons of CH_4 and 25,355,892 metric tons of CO_2.

For the 2019 reporting year in GHGRP subpart W, there were a total of 2,500 wells that reported emissions from the venting of associated gas emissions. The total emissions from these wells were just over 33,900 metric tons of methane (848,000 metric tons CO_2e). Over 90 percent of these methane emissions were reported in three basins—Gulf Coast, Williston, and Permian. Examining this information by State shows that almost half of the venting wells and over 64 percent of the methane emissions from the venting of associated gas occurs in Texas. Texas and North Dakota account for almost 90

[302] *https://www.eia.gov/dnav/ng/ng_prod_oilwells_s1_a.htm.* The number of onshore gas producing oil wells was derived from the ''U.S. Natural Gas Number of Oil Wells'' subtracting ''Federal Offshore—Gulf of Mexico'' wells [336,732—2,390 = 334,342 wells].

[303] *https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGV_mmcf_a.htm.* The volume of vented and flared natural gas was derived from ''U.S. Natural Gas Vented and Flared'' subtracting ''Alaska—State Offshore'' and ''California—State Offshore'' and ''Federal Offshore—Gulf of Mexico'' and ''Louisiana—State Offshore'' and ''Texas—State Offshore'' [538,479 − 825 − 0 − 14,461 − 45 − 82 = 523,066].

percent of the reported methane emissions from vented associated gas oil wells. The average methane emissions from the venting of associated gas in 2019 was 13.6 metric tpy per venting well. The average per State ranges from 0.03 tpy per venting well in California to over 340 tpy per venting well in North Dakota.

The 2019 GHGRP subpart W data also show that there were over 38,000 wells reporting that they flared associated gas, with over 21 million metric tons of CO_2 emissions and over 68,000 metric tons of methane emissions. As with the venting emissions, the majority of the wells flaring associated gas (over 93 percent) were in the Gulf Coast, Williston, and Permian basins. Approximately 96 percent of the CO_2 and methane emissions were reported in these three basins. The majority of the wells flaring associated gas (over 72 percent) and emissions (over 87 percent) were from wells in Texas and North Dakota.

d. Control Options

For new and existing sources (oil wells), options to mitigate emissions from associated gas in order of environmental and resource conservation benefit include:

• Capturing the associated gas from the separator and routing into a gas gathering flow line or collection system;
• Beneficially using the associated gas (*e.g.,* onsite use, natural gas liquid processing, electrical power generation, gas to liquid);
• Reinjecting for enhanced oil recovery; and
• Flaring with legally and practicably enforceable limits.

Typically, State oil and gas regulatory agencies (or, on certain public and Tribal lands, the BLM) regulate venting and flaring of associated gas from oil wells to ensure oil and natural gas resources are conserved and utilized in a manner consistent with their respective statutes. State oil and gas regulatory agencies typically encourage, and in some cases require, capture (conservation) over flaring, then flaring over venting. In addition, these State regulators have adopted a variety of approaches for regulating venting and flaring of associated gas from oil wells. Some require technical and economic feasibility analyses for continuing flaring beyond a certain time (*e.g.,* one year). Some require gas capture plans to track and incrementally increase the percentage of gas captured (rather than flared) over prescribed timelines and some of these include provisions to curtail production in the event of not meeting gas capture goals. Many State oil and gas regulations recognize that there are times when gas capture may not be feasible, such as when there is no gas gathering pipeline to tie into, the gas gathering pipeline may be at capacity, or a compressor station or gas processing plant downstream may be off-line, thus closing in the gas gathering pipeline. Venting is allowed by some State and regulatory agencies in certain circumstances such as emergency or upset conditions, during production evaluation, and well purging or productivity tests. In cases where venting is allowed, these rules typically require reporting of the volume of gas flared and vented (and sometimes a gas analysis), while some States combine flaring and venting information together in publicly accessible well data.

Where flares are allowed, these State oil and gas regulations typically do not include monitoring, recordkeeping and reporting on the performance of the flare and would not be recognized as providing legally and practicably enforceable limits for CAA purposes. Some State environmental regulators address associated gas with a regulation stipulating flaring over venting that includes monitoring, recordkeeping and reporting provisions, while others regulate flaring over venting without monitoring requirements.

The EPA is interested in information on, and the feasibility, of options to utilize associated gas in some useful manner in situations where a sales line is not available. In addition to use as fuel, such options could include conversion technologies where methane is converted into hydrogen or other added value chemicals. The EPA is interested in information on these, as well as other, technologies.

e. 2021 BSER Analysis

In performing the BSER analysis for emissions from associated gas oil wells, we recognize there are similarities between the control options available for associated gas and those available for emissions from oil well completions. We are soliciting comment on these similarities. For both flowback emissions during oil well completions and associated gas production, if the infrastructure exists to allow the routing of the gas to a sales line (*e.g.,* ''into a gas flow line or collection system''), owners and operators will almost always choose that option given the economic benefits of being able to sell the gas. For example, in the 2019 GHGRP subpart W data, applicable facilities reported over 1.2 trillion scf of associated gas was routed to sales lines. This represents only a subset of the total volume of associated gas sent to a sales line, as GHGRP subpart W does not require reporting of this volume in subbasins where the company is not also reporting venting or flaring associated gas.

The environmental benefit of routing all associated gas to a sales line is significant, as there are no methane and VOC emissions. The EPA assumes that in situations where gas sales line infrastructure is available, there is minimal cost to owners and operators to route the associated gas to the sales line. While situations at well sites can differ, which would impact this cost, the EPA believes that in every situation the value of the natural gas captured and sold would outweigh these minimal costs of routing the gas to the sales line, thus resulting in overall savings. Given the prevalence of this practice, the environmental benefit, and the economic benefits to owners and operators, the EPA concludes that BSER is routing associated gas from oil wells to a sales line. The EPA seeks comment on this proposed BSER determination, including comment on how to define whether an oil well producing associated gas has access to a sales line for purposes of this BSER and what factors (such as proximity to an existing sales line) should bear on that determination.

NSPS OOOOa also includes other compliance options that achieve a 100 percent reduction in emissions from recovered flowback gas. These are ''re-inject the recovered gas into the well or another well, use the recovered gas as an onsite fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve.'' 40 CFR 60 60.5375a(a)(1)(ii). The EPA believes that, for associated gas from oil wells, the options of using the gas as an onsite fuel source or for another useful purpose are also viable alternatives to routing to a sales line. However, a significant difference exists between the short-term and relatively small volume of gas recovered during the limited duration of completion flowback versus the consistent flow of recovered gas from ongoing production from the well. Because of this difference, the EPA does not have information that supports re-injecting the associated gas into the well or another well as a viable emissions control alternative. Therefore, the EPA is specifically requesting comment on whether NSPS OOOOb should include re-injecting associated gas as an alternative to routing the gas to a sales line.

The format of the well completion provisions in NSPS OOOOa recognize that routing the recovered gas to a gas flow line or collection system, re-injecting the recovered gas, or using the recovered gas fuel or for another purpose may not be technically feasible. In these situations, owners and operators are required to route the flowback emissions to a completion combustion device.

Similarly, the EPA recognizes that there are associated gas oil wells where there is no access to a gas sales line. Therefore, as an aspect of BSER in these situations, the EPA evaluated the flaring of the associated gas as an option to control emissions for situations where access to a sales line is not available.

As discussed previously, the average annual methane emissions from the venting of associated gas reported in GHGRP subpart W for 2019 is 13.6 metric tpy (14.9 tpy) per venting well. Using a representative gas composition for the production segment, the estimated VOC emissions would be 4.15 tpy per well. We conducted the BSER analysis using this emissions level as a representative well.

The installation and proper operation of a flare can achieve 95 percent and greater reduction in methane and VOC emissions. To be conservative, a 95 percent emission reduction was used for the BSER analysis. Therefore, the resulting emission reductions are 14.2 tpy methane and 3.9 tpy VOC.

The capital cost of a flare is estimated to be $5,719. This was based on a 2011 Natural Gas Star Pro Fact Sheet and updated to 2019 dollars. The resulting capital recovery, assuming a 7 percent interest rate and 15-year equipment life, was $628. The Natural Gas Star Pro report estimated the cost of the natural gas needed for the pilot was $1,800 per year. For this cost analysis, we assumed that this cost was not warranted since the associated gas could be used to fuel the pilot. We are soliciting comments on this cost estimate.

The EPA stresses that 95 percent or greater emission reduction is achievable if the flare is properly operated and maintained. In order to ensure that this occurs, the EPA proposes to apply the requirements in § 60.18 of the part 60 General Provisions to oil wells flaring associated gas. In order to account for the cost of the compliance with these requirements, we assumed that the associated cost would be 25 percent of the total annual costs, or an additional $160. This results in a total estimated annual cost of $785. We are soliciting comment on the estimated costs associated with compliance with the § 60.18 monitoring, reporting, and recordkeeping costs for flares used to control emissions of vented associated gas emissions, and whether those requirements would ensure the flare is achieving the proposed emission reduction of 95 percent or greater.

Based on these annual costs and the emission reductions cited above, the cost effectiveness, using the single pollutant method, is $55 per ton of methane reduction and $200 per ton of VOC reduction. Using the multipollutant approach, the cost effectiveness is $30 per ton of methane and $100 per ton of VOC. These cost effectiveness values are well within the range considered reasonable by the EPA.

As discussed above, while flares significantly reduce the methane and VOC emissions, there are CO, CO_2, and NO_X emissions resulting from the combustion of the associated gas. We estimate that for the representative well, the annual emissions resulting from the flaring of the associated gas would be 50 tpy CO_2, 0.1 tpy CO, and 0.03 tpy NO_X. While these secondary impacts are not negligible, the EPA notes that emissions from flaring represents over an 80 percent reduction in CO_2e emissions as compared to venting.

Based on our analysis, we find that the BSER for reducing methane and VOC emissions from associated gas venting at well sites is routing of the associated gas from oil wells to a sales line. In the event that access to a sales line is not available, we are proposing that 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 a 95 percent reduction in emissions of methane and VOC.

We are requesting comment on the affected facility definition and the overall format of the proposed requirements. The EPA is proposing that an associated gas oil well affected facility be each oil well that produces associated gas. The EPA is soliciting comments on how to define ‘‘associated gas’’ or an ‘‘oil well that produces associated gas.’’ The proposed NSPS OOOOb would require that all associated gas be routed to a sales line. In the event that access to a sales line is not available, the proposed NSPS OOOOb would require that 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 a 95 percent reduction in emissions of methane and VOC.

Under this proposal, every oil well that produces associated gas would be an affected facility and therefore, subject to the rule. For those wells where the associated gas is routed to a sales line, the only requirement would be to certify that this is occurring. Wells that use the associated gas as a fuel or for another purpose would be required to document how it is used. If the associated gas is routed to a flare, all of the proposed monitoring, recordkeeping, and reporting requirements would apply.

As an alternative, the EPA is soliciting comments on defining the affected facility as each oil well that produces associated gas and does not route the gas to a sales line. This would significantly reduce the number of affected facilities, although the burden for owners and operators that route the gas to a sales line would be similar. While they would not be required under NSPS OOOOb to maintain documentation that the gas is routed to a sales line, they would still need to maintain documentation to prove that the well was not an affected facility. Under this alternative, the proposed rule would require that the gas 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 a 95 percent reduction in emissions of methane and VOC. The EPA's concern with this alternative is that while we believe that most owners and operators would route the gas to a sales line if there is access, it would not specifically require routing the gas to a sales line. We expect that the cost of a flare, along with the associated monitoring, reporting, and recordkeeping costs, will provide additional incentive for owners and operators to connect to an available sales line. We are requesting comment on how, under this alternative approach, to incentivize owners and operators even more to capture or beneficially use associated gas. The EPA is specifically requesting comment on whether the proposed requirements will incentivize the sale or productive use of captured gas, and if not, other methods that the EPA could use to incentivize or require the sale or productive use instead of flaring.

2. EG OOOOc

The EPA evaluated BSER for the control of methane from existing associated gas oil wells that do not route the gas to a sales line or to a process for another beneficial use (designated facilities) and translated the degree of emission limitation achievable through application of the BSER into a proposed presumptive standard for these facilities that essentially mirrors the proposed NSPS OOOOb.

First, based on the same criteria and reasoning as explained above, the EPA is proposing to define the designated facilities in the context of those that commenced construction on or before November 15, 2021. Based on information available to the EPA, we did not identify any factors specific to existing sources that would indicate that the EPA should change these definitions as applied to existing sources. As such, for purposes of the emission guidelines, the definition of a designated facility in terms of associated gas oil wells as existing oil wells with associated gas that do not route the gas to a sales line or to a process for another beneficial use.

Next, the EPA finds that the control options evaluated for new sources for NSPS OOOOb are appropriate for consideration in the context of existing sources under the EG OOOOc. The EPA finds no reason to evaluate different, or additional, control measures in the context of existing sources because the EPA is unaware of any control measures, or systems of emission reduction, for the venting of associated gas that could be used for existing sources but not for new sources.

Next, the methane emission reductions expected to be achieved via application of the control measures identified above for new sources are also expected to be achieved by application of the same control measures to existing sources. The EPA finds no reason to believe that these calculations would differ for existing sources as compared to new sources because the EPA believes that the baseline emissions of an uncontrolled source are the same, or very similar, and the efficiency of the control measures are the same, or very similar, compared to the analysis above. This is also true with respect to the costs, non-air environmental impacts, energy impacts, and technical limitations discussed above for the control options identified.

The information presented above regarding the costs related to new sources and the NSPS are also applicable for existing sources. The EPA considers these cost effectiveness values to be reasonable. Since none of the other factors are different for existing sources when compared to the information from discussed above for new sources, the EPA concludes that BSER for existing sources and the proposed presumptive standard for EG OOOOc to be the requirement to route associated gas to a flare or other control device that achieves at least 95 percent control.

Related to control option of flaring with legally and practicably enforceable limits at existing oil wells specifically, enhancing monitoring and performance requirements for flares at existing oil wells may be an important emissions reduction measure. For those operators who have already installed monitoring capability on their existing flares, the additional investment may be minimal to cover reporting of performance. For those existing oil wells where operators do not have flare monitoring installed, the EPA solicits comment both on the flare performance monitoring technology available and the cost of procuring, installing, operating and maintaining such technology. This could include, but is not limited to, digital pilot light monitors, combustion temperature, gas flow meters, gas chromatography (GC) units, and passive remote monitoring of combustion efficiencies at the flare tip. Similar technologies have been used for flares controlling landfill gas, including automated notifications of flare failure. Additional discussion of control devices, including flares, is included in section XIII.D of this preamble.

K. Proposed Standards for Sweetening Units

Sulfur dioxide (SO_2) standards for onshore sweetening units were first promulgated in 1985 and codified in 40 CFR part 60, subpart LLL (NSPS LLL). In 2012, the EPA reviewed the NSPS for the oil and natural gas sector, and the resulting 2012 NSPS OOOO rule incorporated provisions of NSPS LLL with minor revisions to adapt the NSPS LLL language to NSPS OOOO (77 FR 49489). The incorporated provisions required sweetening unit affected facilities to reduce SO_2 emissions via sulfur recovery. The EPA also increased the SO_2 emission reduction standard from the subpart LLL requirement for units with a sulfur production rate of at least 5 long tons per day (LT/D) from 99.8 percent to 99.9 percent. This change was based on the reanalysis of the original data used in the NSPS LLL BSER analysis.

In 2016, the EPA finalized the NSPS OOOOa rule—which established standards for both methane and VOCs for certain equipment, process and activities across the oil and natural gas sector. The final 2016 NSPS OOOOa rule reaffirmed and included the SO_2 emission reduction requirements as specified in the 2012 NSPS OOOO rule (81 FR 35824).

The EPA then amended the 2016 NSPS OOOOa rule in 2020 to correct an affected facility definition applicability error in the rule as it pertains to sweetening units. The 2016 NSPS OOOOa rule erroneously limited the applicability of the SO_2 standards to sweetening units located at onshore natural gas processing plants. This limitation was not included in NSPS LLL, and no reason was identified as to ''why the extraction of natural gas liquids relates in any way to the SO_2 standards such that the standards should only apply to sweetening units located at onshore natural gas processing plants engaged in extraction or fractionation activities'' (85 FR 57398). Therefore, the 2020 NSPS OOOOa final rule amendments corrected the affected facility description applicability error to correctly define affected facilities as any onshore sweetening unit that processes natural gas produced from either onshore or offshore wells at 40 CFR 60.5365a(g).

A sweetening unit refers to a process device that removes H_2S and/or CO_2 from the sour natural gas stream (40 CFR 60.5430a)—*i.e.,* sweetening units convert H_2S in acid gases (*i.e.,* H_2S and CO_2) that are separated from natural gas by a sweetening process, like amine gas treatment, into elemental sulfur in the Claus process. These units can operate anywhere within the production and processing segments of the oil and natural gas source category, including as stand-alone processing facilities that do not extract or fractionate natural gas liquids from field gas (85 FR 57408, September 15, 2020).

An estimated 6,900 tons of SO_2 emissions were reported under the National Emissions Inventory (NEI) for Year 2017 [304] for Source Classification Code 31000201 (Industrial Processes Oil and Gas Production, Natural Gas Production, Gas Sweetening: Amine Process) and SCC 31000208 (Industrial Processes, Oil and Gas Production, Natural Gas Production, Sulfur Recovery Units).

Pursuant to CAA section 111(b)(1)(B), the EPA reviewed the current standards in NSPS OOOOa (including the 2020 revisions) for sweetening units and proposes to determine that they continue to reflect the BSER for reducing SO_2 emissions. The EPA has not identified any greater emissions control level than what is currently required under NSPS OOOOa for sweetening unit affected facilities. Therefore, the EPA is proposing to retain/include the current NSPS OOOOa requirements for sweetening units for the control of SO_2 emissions from sweetening unit affected facilities in NSPS OOOOb. The proposed NSPS OOOOb maintains the requirement that each sweetening unit that processes natural gas produced from either onshore or offshore wells is an affected facility; as well as each sweetening unit

[304] 2017 National Emissions Inventory (NEI) Data | US EPA.

that processes natural gas followed by a sulfur recovery unit. Units with a sulfur production rate of at least 5 long tons per day must reduce SO_2 emissions by 99.9 percent. Compliance with the standard is determined based on initial performance tests and daily reduction efficiency measurements. For affected facilities that have a design capacity less than 2 LT/D of H_2S in the acid gas (expressed as sulfur), recordkeeping and reporting requirements are required; however, emissions control requirements are not required. Facilities that produce acid gas that is entirely re-injected into oil/gas-bearing strata or that is otherwise not released to the atmosphere are also not subject to emissions control requirements.

XIII. Solicitations for Comment on Additional Emission Sources and Definitions

The EPA is considering including additional sources as affected facilities under the proposed NSPS OOOOb and the proposed EG OOOOc. Specifically, the EPA is evaluating the potential for establishing standards applicable to abandoned and unplugged wells, pipeline pigging and related blowdown activities, and tank truck loading operations. While the EPA has assessed these sources based on currently available information, we have determined that we need additional information to evaluate BSER and propose NSPS and EG for these emissions sources. As described below, the EPA is soliciting information to assist in this effort.

The EPA is also assessing whether proposed standards that would require 95 percent reduction based on a combustion control device as the BSER (*e.g.,* standards for storage vessels, centrifugal compressors, pneumatic pumps, and associated gas that cannot be routed to a sales line or consumed for a useful purpose) could be further strengthened, including the potential for additional monitoring and associated recordkeeping and reporting requirements, to ensure proper design and operation of combustion control devices.

While we are not proposing NSPS nor EG for these emissions sources (*i.e.,* abandoned wells, pigging operations, or tank truck loading) or updates to ensure proper design and operation of combustion control devices in this action, the EPA is soliciting comment and information that would better inform the EPA as we continue to evaluate options for these sources. Should the EPA receive information through the public comment process that would help the Agency evaluate BSER for these emission sources, the EPA could consider NSPS and EG for these sources through a supplemental proposal. In this section we summarize the available information that we have evaluated regarding emissions, control options, and where specific States may have existing requirements, and we solicit specific comments. In the case of combustion control devices, we solicit comment on the current standard of 95 percent reduction and what additional monitoring, recordkeeping, and reporting may be appropriate to ensure compliance. We also generally solicit comment and information on the following topics associated with these emission sources.

The EPA solicits comment on the control options discussed below and how these controls may be broadly applied across different basins or geographic areas. The EPA solicits comment on what equipment is onsite during these emission events. The EPA solicits comment on the technical feasibility of control options and any instances where it is not technically feasible to minimize emissions from these sources including, but not limited to, any retrofit concerns for existing sources. The EPA solicits comment on any practices owners and operators already implement as part of voluntary efforts or State requirements to minimize emissions from these sources. The EPA solicits comment on methods/approaches for estimating baseline emissions from these sources, estimating cost of control, and efficiency of control options. Finally, the EPA solicits comment on the cost of maintaining records and submitting reports for these emissions sources, including the types of records that are appropriate to maintain and report.

A. Abandoned Wells

The EPA is soliciting comment for potential NSPS and EG to address issues with emissions from abandoned, or non-producing oil and natural gas wells that are not plugged or are plugged ineffectively. Should the EPA receive information through the public comment process that would help the Agency evaluate BSER, the EPA may propose NSPS and EG through a supplemental proposal.

The EPA broadly characterizes abandoned wells as oil or natural gas wells that have been taken out of production, which may include a wide range of non-producing wells. This includes wells that State governments classify as idle, inactive, dormant, or shut-in, but not plugged. The classification varies from State to State, and State governments may allow these wells to be dormant, without plugging, for varying time periods that may last several years. It also includes wells with no production for many years—sometimes more than a decade—and no responsible operator. These wells are commonly referred to as orphaned, deserted, or long-term idle. Finally, this includes wells that have been abandoned for long periods, known as legacy wells. State governments have varied definitions of temporarily idled, orphaned, or non-producing wells.

It is the EPA's understanding that since non-producing oil and natural gas wells generally are not staffed and are seldom monitored, many have fallen into disrepair. The EPA recognizes that some States and NGOs also have elevated concerns about the potential number of low-production wells that could be abandoned in the near future as they reach the end of their productive lives. The 2021 GHGI estimates that in 2019 the U.S. population of abandoned wells (including orphaned wells and other non-producing wells) is around 3.4 million (about 2.7 million abandoned oil wells and 0.6 million abandoned natural gas wells).[305] These non-producing wells often have methane, CO_2, and VOC emissions. The most recent studies of emissions from abandoned wells focus on methane emissions, which are larger than the CO_2 or VOC emissions from such wells.[306] The GHGI estimates that abandoned oil wells emitted 209 kt of methane and 4 kt of CO_2 in 2019. While emissions of both pollutants from abandoned oil wells decreased by 10 percent from 1990, the total population of these wells increased 28 percent. The GHGI estimates that abandoned gas wells emitted 55 kt of methane and 2 kt of CO_2 in 2019. While emissions of both pollutants increased from abandoned gas wells by 38 percent from 1990, the total population of such wells increased 84 percent.

The large populations of abandoned unplugged wells are likely due to various circumstances. For instance, some operators declare bankruptcy before wells are plugged, and for many, bonding requirements represent only a fraction of the actual costs to plug the well and restore the well site. Wells are also abandoned or idled when changing oil or natural gas prices make them unprofitable to continue production.

[305] The GHGI separates non-producing oil and gas wells into those that are unplugged and plugged. The abandoned wells identified in the GHGI include those that have been taken out of production temporarily, but can return to production, as well as orphan wells.

[306] See TSD at Docket ID No. EPA–HQ–OAR–2021–0317.

The EPA recognizes that many oil and natural gas producing States require the plugging of non-producing oil and natural gas wells, and subsequent restoration of the well site. However, the large number of abandoned, unplugged wells nationwide suggests that Federal standards may be warranted. Many oil and gas producing States specify the time in which wells may remain in idle status without State approval. At the end of that time, States generally require tests of well integrity before giving approval for additional time in this idle status.

In its 2018 survey of idled and abandoned wells, the IOGCC documented State definitions and requirements for idled wells, as well as the management plans for those wells.[307] There is variation in how States define these idle wells, ranging from no definitions to specific definitions for documented and undocumented orphaned and abandoned wells. Further, there is great variability in the allowance for the length of time a well may remain in idle status with or without approval, with some States limiting that time to a few months while other States allow idled status indefinitely. While some States require strict management plans of idled wells, others do not. Finally, some States provide funds for plugging, remediating, and reclaiming orphan wells, and others do not. These funds are supported by civil penalties, settlements, forfeited bonds, and State appropriations. The IOGCC's survey found that 28 States and Canadian provinces have wells approved to remain in idle status, with most having between 100 and 10,000 approved idle wells. Most States and provinces maintain inventories of documented orphan wells and prioritize orphan wells for plugging according to risk. States and provinces reported from zero to 13,266 documented orphan wells, with about half reporting fewer than 100 orphan wells.

The IOGCC's 2018 survey also collected estimates from some States on the number of undocumented orphan wells, including those for which no permits or other records exist. Most of these wells were drilled before there was any regulatory oversight. Ten States reported no undocumented orphan wells. Nine other States did not provide an estimate. Eleven States provided an estimate ranging from fewer than 10 to 100,000 or more undocumented orphan wells. Most of the States surveyed by the IOGCC had established funds dedicated to plugging orphan wells. Money for these funds comes primarily from taxes, fees, or other assessments on the oil and gas industry.

The EPA has identified the following potential strategies to reduce air emissions from these sources. The first strategy is to employ practices and procedures to ensure proper well closure. Under this strategy, the EPA could focus on well closure requirements aimed at preventing future abandonment of unplugged wells and halt the growth of this unplugged population. Given that all wells eventually reach their end of life, this strategy could be applied to both new and existing wells. Under the NSPS, for example, the EPA could require owners or operators to submit a closure plan describing when and how the well would be closed and to demonstrate whether the owner or operator has the financial capacity to continue to demonstrate compliance with the rules until the well is closed and to carry out any required closure procedures per the rule. This demonstration could require some financial assurance or bonding if the Agency determines the financial capacity of the owner or operator to continue to assure compliance with the rule is in doubt. The EPA also could require reporting any transfer of well ownership, along with a copy of the well closure requirements, to the EPA and/or the applicable State when transferring ownership. The Agency might also consider a requirement to temporarily close the well to the atmosphere with a swedge and valve or packer or other approved method once a well is temporarily abandoned or shut in. As one example, this is a requirement under Colorado law for all wells that are designated as shut in or temporarily abandoned.[308]

The primary purpose of detailing financial capacity as part of a compliance plan, and to potentially require some financial assurance bonding, is to ensure that State governments have adequate resources to plug oil and gas wells when the owner or operator is unwilling or unable to do so. The IOGCC notes that States typically have requirements for both single-well or blanket financial assurance. In the IOGCC's 2018 survey, 35 States reported information on the types of financial assurance accepted in their jurisdictions, with most accepting more than one type. The IOGCC noted that the amounts and criteria for bonding vary considerably among the States. Single-well bond amounts range from $1,500 to $500,000 per well; blanket bonds (covering multiple wells) vary from $7,500 to $30,000,000, the IOGCC said. In some States, bond amounts are based on well depth; in others, bond amounts are based on case-by-case evaluations; and in several, bond amounts may be increased if determined necessary.

That study identified the following types of financial assurance, including cash deposit of a payment given as a guarantee that an obligation will be met, certificate of deposit of a financial instrument certifying that the face amount is on deposit with the issuing bank to be redeemed for cash by the State if required, financial statements of a report of basic accounting data that depicts a firm's financial history and activities, letter of credit, irrevocable letter of credit where payment is guaranteed if stipulated conditions are met, security interest giving the right to take property or a portion of property offered as security, and surety or performance bonds as a contract by which one party agrees to make payment on the default or debt of another party. Other forms of financial assurance include certificates of insurance, consolidated financial funds, escrow accounts, and liens. The amounts and criteria for financial assurance vary considerably among the States and provinces.

Another strategy under consideration is to require fugitive emissions monitoring at a specified frequency for the duration of time the well is idled and unplugged. The EPA's understanding, however, is that most idled and non-producing well sites would be classified as wellhead only sites, which the EPA is proposing to exclude from fugitive emissions monitoring for both new and existing well sites (see section XI.A).

The EPA is aware that other Federal agencies have information on, and experience with, abandoned wells, such as the U.S. Forest Service, National Park Service, U.S. Fish and Wildlife Service, and the BLM. On Federal and Tribal mineral estate, the BLM coordinates with the surface management agency when remediating abandoned wells to mitigate the potential risks those wells may pose. The EPA may be informed by the methods employed by the BLM to monitor and remediate abandoned wells on Federal lands, as well as by draft legislative initiatives that may expand the scope of the BLM's efforts. The EPA understands that one such initiative, the "Revive Economic Growth and Reclaim Orphaned Wells (REGROW) Act," could amend the Energy Policy Act of 2005 to

[307] See IOGCC Report located at Docket ID No. EPA–HQ–OAR–2021–0317.

[308] Code of Colorado Regulations, Oil and Gas Conservation Commission, 2 CCR 404–1, paragraph b, "Temporary Abandonment," p. 80.

require the BLM to establish a new program to plug, remediate, and reclaim orphaned oil and gas wells and surrounding land, and to provide funds to State and Tribal governments for this purpose.[309]

The EPA is soliciting additional information that would support a determination of the BSER to address emissions from abandoned, idled, and non-producing wells. The specific information of interest includes updates to the number of abandoned, orphaned, or temporarily idled wells in the U.S., which could be State-specific or basin-specific; fugitive emission estimates for the wells; and costs of mitigation measures, including effective closure requirements and proper plugging practices, financial assurance mechanisms, and requiring fugitive emissions monitoring while in idled and unplugged status. The EPA is also soliciting information on mechanisms to disincentivize operator delay in permanently abandoning wells and/or transfer of late-life assets to companies that may not be well-positioned to fund proper closure. The EPA also solicits information at the State level, on the length of time that wells remain temporarily idled before they must be inspected by State governments. Further, we are seeking information about what would be included in well closure requirements, including what closure requirements are appropriate and any recordkeeping and reporting associated with those requirements, as well as whether it is appropriate to close the well to the atmosphere once it is designated as shut in or temporarily abandoned. The EPA also solicits information on whether compliance assurance for well closure requirements will necessitate certain forms of financial assurance on the part of well owners and operators. The EPA solicits comment on effective plugging, such as criteria or guidelines are necessary for sufficient plugging and post-plugging follow up monitoring necessary over a certain time period. Finally, the EPA solicits comments on the cost of monitoring idled or abandoned wells or monitoring techniques that might lower the costs of such monitoring.

[309] S. 1076, ''To amend the Energy Policy Act of 2005 to require the Secretary of the Interior to establish a program to plug, remediate, and reclaim orphaned oil and gas wells and surrounding land, to provide funds to State and Tribal governments to plug, remediate, and reclaim orphaned oil and gas wells and surrounding land, and for other purposes,'' 117th Congress, 1st Session, as introduced on April 12, 2021, available at *https://www.congress.gov/117/bills/s1076/BILLS-117s1076is.xml.*

B. Pigging Operations and Related Blowdown Activities

The EPA is soliciting comment for potential NSPS and EG under consideration that include addressing emissions from pipeline pigging and related blowdown activities. Should the EPA receive information through the public comment process that would help the Agency evaluate BSER, the EPA may propose NSPS and EG through a supplemental proposal.

Raw natural gas is transported from production wells to natural gas processing plants through networks of gathering pipelines. After natural gas processing, pipeline networks in the transmission and storage segment transport the gas to downstream customers. Raw natural gas is frequently saturated with hydrocarbons and may contain other components such as water, carbon dioxide, and hydrogen sulfide, especially upstream of the natural gas processing plant. Liquid condensates can accumulate in low elevation segments of the gathering pipelines, impeding the flow of natural gas. To maintain gas flow and operational integrity of the gathering pipelines, operators mechanically push these condensates out of the low elevations and down the pipeline by an operation called ''pigging,'' which involves first inserting a device called a pig[310] into a pig launcher upstream of the pipeline segment where condensates have accumulated. The natural gas flowing through the pipeline then pushes the pig through the pipeline, allowing the pig to sweep along the accumulated condensates. The pig is removed from the pipeline segment when it is caught in a pig receiver. Pigging operations are also conducted using ''smart'' pigs that are equipped with sensors to collect data about the pipeline's structural characteristics and integrity for safety and maintenance purposes.

Before a pig can be inserted or removed through the hatch of a pig launcher or a pig receiver, the pipeline gas in the launcher or receiver barrel must be removed. It is common practice to vent the gas directly to the atmosphere where gas capture or control are not used. This gas is under the same pressure as the pipeline and contains methane, ethane, and VOCs including HAP such as benzene, toluene, ethylbenzene, and xylene. Emissions can also result from the volatilization of collected condensate liquid when the pig barrel is depressurized.

[310] Pigs are typically spherical, barrel- or bullet-shaped objects slightly smaller than the diameter of the pipeline.

Pig launchers and receivers can be installed within larger facilities, such as at a compressor station or natural gas processing plant, or can be ''stand-alone'' sites, where the only equipment at a particular location is related to pigging operations. Additionally, sections of pipeline or equipment that are separate from the pig launcher or receiver may need to be evacuated of gas for reasons other than pigging, such as routine maintenance or inspection activities. Emissions from blowdowns can be calculated by accounting for the volume of the section of pipeline or equipment being evacuated, composition of that gas being vented, pressure of the gas vented, frequency of the blowdown activity, and inclusion of emissions from any volatile liquids present in the pipeline section or equipment being vented.

The EPA is aware of some State and local governments have regulations in place that address blowdown activities, including pigging. These include limits on the amount of emissions from pigging operations, required use of add-on controls, and implementation of best management practices.[311] Estimating emissions from pigging operations is fairly straightforward if all variables (*e.g.,* volume, pressure, and composition of gas) are known. However, the wide range of variables, which are applied in different combinations and are dependent on the frequency of blowdown events, can make it challenging to estimate total nationwide emissions from pigging and related blowdown activities. For example, in 2019, six of the eight operators reporting to GHGRP subpart W in the Uinta Basin reported a collective 7,299 blowdown events due to pigging that met the threshold for reporting under GHGRP subpart W, but the attribution of emissions from each individual pigging event is undetermined at this time.[312] Data reported in 2019 under GHGRP subpart W include 472,995 total individual blowdown events from 1,212 facilities for a combined 307,630 metric tons of methane emitted, including 79,746 events at pig launchers or receivers for a combined total of 19,066 metric tons of methane, however, these data only include emissions from blowdown equipment with a unique physical volume greater than 50 cubic feet and occurring at a facility with total emissions greater than 25,000 metric

[311] See TSD located at Docket ID No. EPA–HQ–OAR–2021–0317.

[312] EPA (2020) Greenhouse Gas Reporting Program. U.S. Environmental Protection Agency. Data reported as of September 26, 2020.

tons CO_2 Eq.[313] The EPA is also aware of a single operator in the Marcellus Shale region that operates around 400 pig launchers and receivers which collectively emit approximately 1,335 metric tons of methane annually, but the total annual emissions from each launcher or receiver varies widely, due to variations in the inputs used to calculate emissions from an individual pigging event.[314] The EPA is seeking comment on the availability of nationwide data sets or methodologies to better identify the total inventory of pig launchers and receivers, and, if no such data set or proxy exists, comment on the most defensible method of calculating total emissions from pigging and related blowdown activities.

The EPA has identified the following potential control options that can reduce emissions from pipeline pig launchers and receivers: (1) Reducing the frequency that the pig launcher or receiver must be evacuated of gas; (2) eliminating or reducing the volume of gas vented during blowdowns; (3) using add-on controls that are applied to blowdown emissions; or (4) a combination of these strategies. The EPA has identified the following systems as potential control strategies to evaluate further.

First, pig ball valves are a design alternative to conventional pig launcher and receiver systems that have a smaller sized barrel (or chamber) that launches and receives the pig, thus resulting in reduced emissions from pigging operations. A conventional pig launcher or receiver system can be retrofitted by replacing the conventional launcher and receiver barrels with special ball valves used to insert and remove the pig directly from the main pipeline. By replacing the large volume barrel with the much smaller volume ball valve, the volume of gas vented during each pigging operation can be reduced by as much as 80 to 95 percent, with a corresponding reduction in emissions and other risks associated with pipeline pigging operations. The net cost of a pig ball valve compared to a traditional launcher/receiver should consider not only the cost of the valve and its installation, but also the savings realized from the prevention of large quantities of vented gas and personnel time spent blowing down a larger launcher/receiver. These costs and savings will vary according to site-specific dimensions, gas composition, and pigging frequency. The EPA understands that not every dimension of pipeline and pig launcher or receiver can use a pig ball valve and seeks further comment on specific circumstances where such equipment is appropriate, potential challenges to using a pig ball valve or retrofitting a launcher or receiver to accommodate a pig ball valve, and specific costs of installing or retrofitting a launcher or receiver compared to a conventional full-barrel launcher or receiver.

Second, multi-pig launcher systems are a design alternative to conventional launcher/receiver systems and reduce pigging emissions by reducing the frequency that launchers and receivers must be opened to the atmosphere and vented prior to pig insertion and removal. The launcher barrel is designed to hold multiple spherical pigs, which are each held in place by gates or pins prior to release. Emission reductions are approximately proportional to the reduction in frequency of opening the launcher and receiver hatch. For example, if a pig launcher holds six pigs, which are loaded all at once, the frequency of venting of the pig barrel is reduced to one-sixth of what it would have been if each pig were loaded individually. The EPA understands that multi-pig launchers and receivers are most appropriate for large diameter pipelines where the footprint of the launcher or receiver site is large enough to accommodate such a system. The EPA seeks comment on specific circumstances where such equipment is appropriate, and requests information on emission reductions and specific costs and savings of installing or retrofitting and operating a multi-pig launcher or receiver compared to a conventional single-pig launcher or receiver.

Next, there are several liquids management technologies that focus on reducing emissions from the liquid condensate that is collected during pigging operations. The first technology relates to the design of condensate drains on receiver barrels. Drains can be installed in the bottom of receiver barrels and pig ball valves to ensure that all condensate is drained from the system prior to depressurization. These drains generally route the condensate back into the main pipelines, to onsite storage tanks, or to onsite processes via enclosed piping and can be retrofitted to existing systems. Recovering condensate prevents emissions that would occur when the liquids volatilize during depressurization of the pig receiver. The EPA seeks comment on different configurations of condensate drains, how the recovered condensate is routed and managed, limitations on using this technology, and data showing the amount of condensate recovered and associated emissions prevented.

The second liquids management technology is a pig ramp on a receiver barrel. A pig ramp[315] is a simple device that can be installed inside a receiver barrel to allow liquids trapped in front of the pig to be captured and to allow liquids clinging to the pig itself to drain before the pig is pulled from the chamber. Pig ramps are typically used in conjunction with condensate drains. The pig ramp promotes the flow of liquid through the barrel and into the drain line by elevating the pig on a rack-like apparatus within the receiver barrel, thereby preventing the pig from creating blockages in the receiver. By promoting the flow of liquid to a location within the receiver or pipeline where the liquids can be captured and drained prior to depressurization, pig ramps reduce the amount of condensed VOCs that would otherwise volatilize during depressurization and removal of the pig from the receiver, thereby reducing emissions. The EPA seeks comment on the successful installation and use of pig ramps as well as information on cost, emission reductions, and concerns or challenges that may make the use of pig ramps inappropriate.

The third liquids management technology involves enhanced liquids containment. If recovered condensate cannot be routed back to the pipeline or to controlled storage vessels, covering containers that collect liquids remaining in a receiver barrel after depressurization with a fitted impermeable material will reduce emissions from evaporation. However, whether or not this strategy will ultimately reduce emissions depends on how the recovered condensate is actually managed. The EPA seeks comment on how recovered condensate can be managed to ensure that emissions from the volatilization of the liquids is minimized, thereby achieving emissions reductions.

Lastly, the EPA has identified several additional control options that can be employed to reduce emissions. First, an owner or operator could install ‘‘jumper lines’’ that allow routing high pressure systems to lower pressure systems. The depressurization emissions from high pressure launchers and receivers can be reduced by routing the high-pressure gases to a lower pressure system before venting the remaining gases to the atmosphere or to control equipment.

[313] Id.

[314] See Appendix A to the TSD located at Docket ID No. EPA–HQ–OAR–2021–0317.

[315] *https://www.mplx.com/content/documents/mplx/markwest/Launcher%20Receiver%20Design%20Detail.pdf.*

Routing to a lower pressure system is achieved with a depressurization line (or jumper line) exiting the top of the barrel, or exiting the top of the pig ball valve, and connecting to nearby low-pressure lines on site. Compressor stations and gas plants have low pressure lines on the site that typically can receive these depressurized gases and recycle them through the process. Similarly, launchers and receivers along high pressure pipelines are occasionally located near low pressure pipelines that can receive depressurized gases exiting the barrel or pig ball valve. The EPA seeks comment on the universe of sites where jumper lines are feasible to install, as well as information on cost, emission reductions, and comment on implementation successes and challenges.

Second, owners and operators can route low-pressure systems into a fuel gas system or VRU. Gases that remain in high pressure barrels after venting to low pressure systems, and gases in low pressure barrels, can be recovered during depressurization by discharging the gases to very low-pressure systems at the site (*e.g.,* 10–15 psig). Two examples of very low-pressure systems at compressor stations are a fuel gas system and a condensate tank VRU. Applying such an approach can reduce the gas pressure in the barrels to the pressure of the very low-pressure system, with a corresponding reduction in depressurization emissions. The feasibility of this option is contingent upon the presence of such equipment already onsite. The EPA seeks comment on the universe of sites where routing gas to low-pressure systems is feasible, as well as information on cost, emission reductions, and comment on implementation successes and challenges.

Third, owners and operators can utilize barrel pump-down systems. In barrel pump-down systems, small fixed or portable compressors are used to pump vapors in the receiver or a launcher barrel back into the main pipeline prior to venting and opening the barrel hatch. In barrel pump-down systems, the inlet of a gas compressor is connected to the receiver or launcher depressurization line, and the compressor discharge is connected into the main pipeline. Vapors exiting the depressurization line are pulled into the compression system and recovered back into the pipeline at system pressure. These control systems can recover greater than 99 percent of the depressurization vapors from pig launchers and receivers. The EPA seeks comment on the universe of sites where barrel pump-down systems are feasible, as well as information on cost, emission reductions, and comment on implementation successes and challenges.

Finally, owners and operators could route depressurization gases to combustion devices to control emissions from pigging operations. Depressurization gases from barrels and pig ball valves can be routed through the depressurization line to onsite combustion devices. Well-designed and operated combustion devices can achieve vapor destruction efficiencies as high as 95 to 98 percent. Combustion devices can be used in conjunction with engineering solutions discussed above that first reduce accumulation of or recover as much natural gas and condensate as possible, before destroying the remaining vapors in the combustion device. An example would be to route high pressure systems to low pressure lines and drain barrel condensate, then route the remaining vapors to a combustion device. The EPA understands that large, high-capacity combustion devices are typically available at compressor stations and processing plants and can be used to control pigging gases while meeting the other flaring needs of the facility. There are also numerous low-capacity combustion devices available for serving remote launcher/receiver sites. The EPA seeks comment on the universe of sites where routing depressurization gases from pigging operations to a combustion device is feasible, as well as information on cost, emission reductions, and comment on implementation successes and challenges.

In addition to those methods already identified above for reducing emissions from pigging and related blowdown activities, the EPA is seeking comment on other existing technologies and work practices to reduce the need for blowdown events or reduce emissions from blowdown events when they occur. The EPA is specifically interested in the costs of such technologies or work practices and any variables impacting cost, the control efficiency of the technology or work practice and variables affecting efficiency, and any technological or logistical limitations to implementing the technology or work practice.

While blowdown emissions due to pigging are the primary area where the EPA seeks comment, the EPA is aware that planned blowdowns occur for many reasons, typically related to maintenance or inspection activities. Planned blowdowns may occur at facilities such as a gas processing plant, compressor station, well pad, or stand-alone pig launcher and receiver station, but may also occur at locations other than these facilities, including along pipelines. Under GHGRP subpart W, blowdown vent stack equipment or event types are grouped into the following seven categories: Facility piping (*i.e.,* piping within the facility boundary), pipeline venting (*i.e.,* physical volumes associated with pipelines vented within the facility boundary), compressors, scrubbers/strainers, pig launchers and receivers, emergency shutdowns (this category includes emergency shutdown blowdown emissions regardless of equipment type), and all other equipment with a physical volume greater than or equal to 50 cubic feet.[316] The EPA seeks comment on any substantive differences between pigging blowdowns and other types of planned blowdowns. Further, the EPA is soliciting comment on how to define an affected facility that includes these blowdown activities, and specific limitations (*e.g.,* technical or logistical) to including non-pigging-related types of blowdowns as part of affected facilities. In particular, the EPA is considering whether the pipeline itself could be defined as an affected facility for purposes of regulating blowdowns. In this scenario, the owner or operator of the pipeline would be responsible for complying with any requirements in place for blowdown activities that occur anywhere along the pipeline. The EPA is soliciting comment on any potential concerns this type of approach would raise for owners and operators, particularly where pipelines cross State boundaries or at the location where pipeline ownership may change from the upstream owner to a different downstream owner.

C. Tank Truck Loading

The EPA is considering including emission standards and EG for tank truck loading operations; however, additional information is needed to evaluate BSER and propose NSPS or EG for this emissions source. The EPA is therefore soliciting comment on adding tank truck loading operations as an affected facility in both the NSPS and EG. Depending on the information received through the public comment process, the EPA may propose NSPS and EG for this source through a supplemental proposal. In this section we summarize the available information we have reviewed for this emissions source and potential control options.

Tank truck loading operations result in emissions when organic vapors in empty tank trucks are displaced to the

[316] 40 CFR 98.233(i)(2).

atmosphere as crude oil, condensate, intermediate hydrocarbon liquids, or produced water from storage vessels is loaded into the tank trucks.[317] Tank truck loading emissions are the primary source of evaporative emissions from tank trucks. It is the EPA's understanding that these vapors are a composite of vapors formed in the empty tank truck by evaporation of residual materials from previous loads, vapors transferred to the tank truck in vapor balance systems as materials are being unloaded, and vapors generated in the tank truck as new material is being loaded. Further, the quantity of evaporative losses from loading operations is, therefore, a function of the parameters such as the physical and chemical characteristics of the crude oil, condensate, intermediate hydrocarbon liquids, or produced water; the method of unloading the crude oil, condensate, intermediate hydrocarbon liquids, or produced water from the storage vessel into the tank truck; and the operations to transport the empty tank truck off-site. The composition of evaporative losses includes VOC, methane, and some HAP.

According to the 2017 NEI, VOC emissions from tank truck loading operations were approximately 72,448 tpy, of which over 70,990 tpy were emitted in the crude oil and natural gas production segment, with the balance of approximately 1,457 tpy emitted from the natural gas processing segment. According to the Oklahoma loading losses guidance, [318] a loading loss vapor VOC content of 85 percent by weight (*i.e.,* 15 percent by weight methane and ethane) may be assumed at wellhead facilities. Condensate and crude oil being loaded at a facility other than a wellhead facility may assume a vapor VOC content of 100 percent. Applying these compositions to the emissions in the 2017 NEI results in approximately 12,528 tpy methane at well sites and 1,457 tpy methane from other segments.

According to EIA, the contiguous continental states area comprising of 48 States have a six year daily average condensate production (API gravity greater than or equal to 50) [319] of 911,000 bbls/day.[320] Emissions per barrel of liquids loaded into tank trucks may be estimated at 0.43lb VOC/bbl. It is the EPA's understanding that most sites use tank trucks with a capacity of approximately 130 bbl. The EPA solicits comment on whether API gravity greater than or equal to 50 is the appropriate gravity of condensate to use.

The EPA understands that there are three options generally in use for controlling emissions during the tank truck loading process. The first control option is vapor balancing which is used to route the vapors displaced during material loading from the tank truck back to the storage vessel. Vapor balancing requires a vapor capture line to connect the tank truck to the storage vessel or manifold system of a tank battery. Because vapor balancing is a closed system, the only anticipated emissions from this control option would be fugitive in nature. However, emissions may occur from the tank truck if it is not properly maintained to DOT specifications, or when the tank truck is cleaned or reloaded without control off-site. Vapor balancing does not have any secondary air impacts or energy requirements. We estimate the capital cost associated with a vapor balancing loading arm (equipment associated with a capture line to connect the tank truck to the storage vessel) at about $5000 per arm based on limited available information.

The second control option is use of a closed vent system operating with a reduction efficiency of 95 to 99 percent. A vapor capture system is used and routed to a vapor recovery device (VRD) or VRU which uses refrigeration, absorption, adsorption, and/or compression. The recovered liquid product is piped back to storage. Alternatively, the vapors may be collected via a vapor capture system and routed to an on-site thermal oxidizer or flare. It is possible to route emissions from this closed vent system to an existing control device located on-site for another purpose. The EPA recognizes that this option may have secondary impacts dependent on the type of control chosen (*e.g.,* VRU, VRD, or combustion device).

Finally, the third option is to directly pipe liquids downstream. By directly piping liquids downstream, no emissions from tank truck loading are released to the atmosphere. We are not aware of any secondary impacts or energy costs associated with this option. However, the EPA is also unsure if this option is technically feasible for every site. It is our understanding that this option requires access to pipelines that can transport the crude oil and/or condensate to downstream locations, and availability of pipelines or capacity to move these liquids in existing pipelines may present an issue with requiring this option for all sites.

In addition to these three control options, the EPA has also identified work practices related to the method of loading which are important and play a role in minimizing air emissions. Practices such as submerged fill and bottom loading help reduce emissions when the fill pipe opening is below the liquid surface level which reduces liquid turbulence and results in much lower vapor generation than encountered during splash (top) loading. We estimate the capital costs of submerged fill loading arms are approximately $1,500 per arm based on limited available data at this time.

The EPA is soliciting comment on the three control options and work practices presented in this section to control or reduce emissions resulting from the tank truck loading process. We solicit comment on other control options or other work practice standards similar to those used in other sectors such as petroleum refineries and how appropriate those options may be for the Crude Oil and Natural Gas source category. We solicit comment on how widely used the control measure and work practices are, any feasibility challenges, and estimates of baseline emissions and cost information associated with these control options and work practices. The EPA is aware of several State regulations that have established standards for this emissions source.[321] Finally, the EPA solicits comment on any practices owners and operators already implement as part of voluntary efforts or State requirements to minimize emissions from these sources.

D. Control Device Efficiency and Operation

As discussed above in sections XI.B, F, and G and XII.B, F, and G, the EPA is proposing to retain the 95 percent reduction performance standard for storage vessels, wet seal centrifugal compressors, and pneumatic pumps based on our analysis showing that a combustion control device remains the BSER for these affected facilities and can reliably achieve this performance standard. This 95 percent reduction is generally achieved by capturing the emissions in a closed vent system that routes those emission to either a control device or back to the process. Under the 2016 NSPS OOOOa, as amended by the 2020 Technical Rule with further

[317] Section 5.2.2.1.1 of the AP–42 Section 5.2: Transportation and Marketing of Petroleum Liquids *https://www.epa.gov/sites/default/files/2020-09/documents/5.2_transportation_and_marketing_of_petroleum_liquids.pdf.*

[318] See *https://www.deq.ok.gov/wp-content/uploads/deqmainresources/LoadingLosses Guidance_08-2019.pdf.*

[319] See *https://glossary.oilfield.slb.com/en/terms/c/condensate.*

[320] See *http://www.eia.gov/dnav/pet/pet_crd_api_adc_mbblpd_m.htm* and TSD located at Docket ID No. EPA–OAR–HQ–2021–0317.

[321] See TSD located at Docket ID No. EPA–OAR–HQ–2021–0317.

amendments proposed in this action, closed vent systems must be designed and operated with no detectable emissions, which is defined as either no emissions detected greater than 500 ppm above background with EPA Method 21, no emissions detected with OGI, or no audible, visual, or olfactory emissions detected. Thus, for a closed vent system, the assumed control efficiency is 100 percent. Therefore, any control device used must be designed and operated to achieve at least 95 percent reduction of emissions to comply with the standard. Examples of control devices include flares, thermal oxidizers, catalytic oxidizers, enclosed combustion devices, carbon adsorption systems, condensers, and VRUs. However, there are various data sources available that suggest combustion control devices, which we have again identified as the BSER for these affected facilities, can achieve a continuous destruction efficiency of 98 percent.[322]

Therefore, the EPA is soliciting comment on potentially proposing a change in the standards for wet seal centrifugal compressors, storage vessels, and pneumatic pumps that would require 98 percent reduction of methane and VOC emissions from these affected facilities. It is the EPA's understanding that combustion control devices, such as flares and enclosed combustion devices, may achieve at least 98 percent control of all organic compounds. Further, as noted in AP–42 Chapter 13.5, properly operated flares achieve at least 98 percent destruction efficiency in the flare plume in normal operating conditions.[323] However, the EPA has received some data [324] relevant to the use of these controls at oil and gas facilities that indicates air-assisted and steam-assisted flares have been found operating outside of the conditions necessary to achieve at least 98 percent control efficiency on a continuous basis. Therefore, the EPA is soliciting comment and information that would help us better understand the cost, feasibility, and emission reduction benefits associated with establishing a 98 percent control efficiency requirement for flares in the Crude Oil and Natural Gas source category, including information on the level of performance being achieved in practice by flares in the field, what conditions or factors contribute to malfunctions or poor performance at these flares, and what measures the EPA could or should require in order to ensure that flares perform at a 98 percent level of control.

The EPA also requests comment on whether additional measures to ensure proper performance of flares would be appropriate to ensure that flares meet the current 95 percent control requirement. For example, the EPA is soliciting comment on the specific requirements that could be used to demonstrate continuous compliance when using a combustion control device. In its July 8, 2021, report, the Office of Inspector General (OIG) [325] observed that State permitting authorities had difficulty verifying continuous compliance with combustion efficiency requirements for flares and enclosed combustors. The OIG recommended that the EPA explore additional means to verify continuous compliance in NSPS OOOO and NSPS OOOOa that would provide additional tools for State agencies to properly permit and enforce combustion efficiency. In considering this recommendation, the EPA has determined that additional information is necessary to support the development of cost-effective continuous compliance requirements.

The current standards in NSPS OOOO and NSPS OOOOa require owners and operators to perform an initial demonstration of compliance for all control devices used to meet the standards in the rule. Further, NSPS OOOO and NSPS OOOOa require monthly EPA Method 22 observations to demonstrate continuous compliance with visible emission requirements, in addition to monitoring for the presence of a pilot light. When an enclosed combustion device is used, owners and operators may demonstrate initial compliance through field testing or through manufacturer testing. The EPA maintains a list of devices for which manufacturers have demonstrated compliance with the testing requirements, including achieving a destruction efficiency of at least 95 percent. The devices that have demonstrated compliance through manufacturer testing have achieved greater than 98 percent destruction efficiency; however, this is demonstrated in a testing environment only, and while the testing is designed to challenge the units, the units may not necessarily demonstrate the same destruction efficiency in field applications. The EPA is seeking comment on alternative means to demonstrate continuous compliance with the required control efficiency (whether maintained at 95 percent or increased to 98 percent).

The Petroleum Refinery Sector Standards, 40 CFR part 63, subpart CC, were amended in 2015 (80 FR 75178) to include a series of additional monitoring requirements that ensure flares achieve the required 98 percent control of organic compounds. Previously these flares had been subject to the flare requirements at 40 CFR 60.18 in the part 60 General Provisions. More recently, the updated flare requirements in NESHAP subpart CC have been applied to other source categories in the petrochemical industry, such as ethylene production facilities (40 CFR part 63, subpart YY), to ensure that flares in that source category also achieve the required 98 percent control of organic compounds. These monitoring requirements include continuous monitoring of waste gas flow, composition and/or net heating value of the vent gases being combusted in the flare, assist gas flow, and supplemental gas flow. The data from these monitored parameters are used to ensure the net heat value in the combustion zone is sufficient to achieve good combustion. The monitoring also includes prescriptive requirements for monitoring pilot flames, visible emissions, and maximum permitted velocity. Lastly, where fairly uniform, consistent waste gas compositions are sent to a flare, owners or operators can simplify the monitoring by taking grab samples in lieu of continuously monitoring waste gas composition, and in some instances, engineering calculations can be used to determine flow measurements.

While effective, the EPA seeks comment on how appropriate any such monitoring requirements and systems would be for the oil and gas production, gathering and boosting, gas processing, or transmission and storage segments subject to the proposed NSPS OOOOb and EG OOOOc. The EPA seeks comment on how to distinguish among flare units where such monitoring is practical, and alternatives where such systems are not practical because they

[322] *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for the Final New Source Performance Standards;* EPA–HQ–OAR–2010–0505–7631, pp. 19–20.

[323] *https://www.epa.gov/sites/default/files/2020-10/documents/13.5_industrial_flares.pdf.*

[324] ''Intermittency of Large Methane Emitters in the Permian Basin'' Daniel H. Cusworth, et al. Environmental Science & Technology Letters 2021 8 (7), 567–573 DOI: 10.1021/acs.estlett.1c00173; and Irakulis-Loitxate, I., Guanter, L., Liu, Y.N., Varon, D.J., Maasakkers, J.D., Zhang, Y., Lyon, D., . . . & Jacob, D. J. (2021). Satellite-based characterization of methane point sources in the Permian Basin (No. EGU21–15877). Copernicus Meetings.

[325] EPA Office of Inspector General Report ''EPA Should Conduct More Oversight of Synthetic-Minor-Source Permitting to Assure Permits Adhere to EPA Guidance,'' Report No. 21–P–0175 July 8, 2021.

lack continuous, on-site personnel or do not have the supporting infrastructure.

Additionally, the EPA seeks comment on several facets of ongoing compliance, including: (1) Owner or operator experience in determining the proper location of a thermocouple for monitoring the presence of a pilot flame, and how to avoid pilot flame failure; (2) how OGI may be used to identify poor combustion efficiency (*e.g.,* to effectively utilize OGI to qualitatively screen enclosed combustion devices) for additional quantitative testing. As noted in Section XI.A.1 of this preamble, we are proposing that emissions resulting from control devices operating in a manner that is not in full compliance with any Federal rule, State rule, or permit, are also considered fugitive emissions. However, there may be other ways to use OGI beyond seeing these fugitive emissions to determine whether control devices are operating properly. For instance, the EPA is interested in how OGI has been used to evaluate heat signature of gases exiting the top of the stack and/or the presence of any unburned hydrocarbon trailing or advective plumes.

With respect to enclosed combustors, the EPA is seeking information on the development of comprehensive specifications for creating an operating envelope under which a make/model can achieve 98 percent reduction (*i.e.,* parameters that should be identified on enclosed combustion device specification sheets), such as maximum heat load, minimum heat load, minimum inlet pressure of waste gas stream, temperature of combustion zone (and proper location for temperature monitor), air intake rate, operation and maintenance necessary for optimal combustion. The EPA also seeks information on real-time monitoring of enclosed combustion device inlet waste gas stream pressure aimed at achieving higher combustion efficiency.

The EPA is also soliciting comment on the current use of non-combustion control devices, the practicality of requiring 98 percent reduction through the use of non-combustion control devices, and the monitoring requirements necessary to demonstrate initial and continuous compliance with such control efficiency. NSPS OOOO and NSPS OOOOa require parametric monitoring for condensers, carbon adsorption systems, and similar control devices, to demonstrate continuous compliance. However, the EPA is seeking comment on whether those monitoring requirements are sufficient to assure continuous compliance should the EPA propose a requirement of 98 percent reduction. In addition to monitoring requirements, the EPA is seeking information on what additional records should be maintained and/or reported for demonstrating continuous compliance when non-combustion control devices are used. The EPA is particularly concerned that increasing the level of control from 95 to 98 percent would disincentivize use or potentially force replacement of non-combustion control devices entirely, including those that capture product for reuse in vapor recovery systems. For example, Texas requires additional monitoring and other significant engineering upgrades for a VRU operator to meet a higher control efficiency than 95 percent.[326] Adding to this concern is the potential increase in overall costs of the rule and potential increase in emissions where facilities replace non-combustion control devices with combustion control devices.

Finally, the EPA is seeking comment on new technologies that would address control efficiency from flares specifically and provide real-time or near real-time measurement of control efficiency. One example would be OGI continuous flame imaging systems that capture flame size and temperature to ensure these parameters are within acceptable ranges. New optical technology is in the early phases of development and deployment. The EPA acknowledges that it may be challenging to analyze costs and reductions without comprehensive data specific to a particular technology, but in the interest of a forward-looking standard, we seek information on potential methods to assure continuous compliance for these control devices.

E. Definition of Hydraulic Fracturing

During pre-proposal outreach, a number of small businesses stated that the NSPS has unintentionally been applied to conventional and vertical wells that engage in hydraulic fracturing. The small business stakeholders contended that these wells have a very different profile from unconventional or horizontal wells in terms of footprint, water usage, chemical usage, equipment used, and flowback period. They recommended that the EPA explicitly exempt these wells from the proposal. We maintain that the original intent of the NSPS was to regulate hydraulically fractured wells, in both conventional and unconventional reservoirs,[327] and both vertical and horizontal wells.[328]

NSPS OOOOa defines hydraulic fracturing as ''the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.'' The NSPS does not offer numeric thresholds that define ''tight formations'' or ''high rate, extended flowback''. When developing the original NSPS OOOO, EPA's analysis assumed hydraulic fracturing is performed in tight sand, shale, and coalbed methane formations which have an in situ permeability (flow rate capability) to gas of less than 0.1 millidarcy.[329] The EPA also assumed the flowback lasted between 3 and 10 days for the average gas well,[330] and 3 days for the average oil well.[331] However, in response to a public comment on the 2015 NSPS OOOOa proposal claiming the definition of hydraulic fracturing was too broad, the EPA clarified it intended to ''include operations that would increase the flow of hydrocarbons to the wellhead''.[332] Similarly, in response to a public comment seeking an exemption for wells that have a flowback period of less than 24 hours, the EPA acknowledged that there is a range of flowback periods, finding that the requested exemption was not warranted.[333]

We are soliciting comment on if numeric thresholds for ''tight formations'' or ''high rate, extended flowback'' are appropriate to include in the definition of hydraulic fracturing, and if so, what those numeric thresholds should be. Alternatively, we solicit comment on if it is appropriate to align the NSPS definition with the U.S. Geologic Survey (USGS) definition of hydraulic fracturing (''the process of injecting water, sand, and/or chemicals into a well to break up underground bedrock to free up oil or gas

[326] See *Vapor Recovery Unit Capture/Control Guidance* located at *https://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/vapor-rec-unit.pdf.*

[327] See Docket ID Item Nos. EPA–HQ–OAR–2010–0505–0445, Chapter 4, p. 4–2 and EPA–HQ–OAR–2010–0505–4546, p. 30.

[328] See Docket ID Item No. EPA–HQ–OAR–2010–0505–4546, p. 61.

[329] See Docket ID Item No. EPA–HQ–OAR–2010–0505–0445, Chapter 4, p. 4–2.

[330] See Docket ID Item No. EPA–HQ–OAR–2010–0505–0445, Chapter 4, p. 4–1.

[331] See Docket ID Item No. EPA–HQ–OAR–2010–0505–5021, p.20.

[332] See Docket ID Item No. EPA–HQ–OAR–2010–0505–7632, Chapter 3, p. 3–113.

[333] See Docket ID Item No. EPA–HQ–OAR–2010–0505–7632, Chapter 3, p. 3–64.

reserves''),[334] which may more accurately capture the EPA's original intent.

XIV. State, Tribal, and Federal Plan Development for Existing Sources

Over the last forty years, under CAA section 111(d), the agency has regulated four pollutants from five source categories (*i.e.,* sulfuric acid plants (acid mist), phosphate fertilizer plants (fluorides), primary aluminum plants (fluorides), kraft pulp plants (total reduced sulfur), and municipal solid waste landfills (landfill gases)).[335] In addition, the agency has regulated additional pollutants under CAA section 111(d) in conjunction with CAA section 129.[336] The Agency has not previously addressed emissions of GHGs (in the form of limitations of methane) from the Crude Oil and Natural Gas source category under CAA section 111(d). However, the EPA has ample experience with this source category from implementing the NSPS for so long, and has examined existing sources in a variety of context including the 2013 Federal Implementation Plan (FIP) for oil and natural gas well production facilities on the Fort Berthold Indian Reservation (78 FR 17836 (Mar. 22, 2013)), the 2016 Oil and Natural Gas Control Techniques Guidelines (81 FR 74798 (Oct. 27, 2016)), and the 2020 proposed FIP for managing emissions from oil and natural gas sources on Indian country lands within the Uintah and Ouray Indian Reservation (85 FR 3492 (Jan. 21, 2020)). The draft EG contained in this proposal draw from, among other sources of information and analysis, all of these experiences combined with information on State laws that regulate existing sources. In this action, the EPA is proposing EG for Sates 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.

A. Overview

While section IV of this preamble provides a general overview of the State planning process triggered by the EPA's finalization of EG under CAA section 111(d), this section explains the EG process and proposed State plan requirements in more detail, and also solicits comment on various issues related to this EG. The EG process is governed by CAA section 111(d) as well as the final EG and the EPA's implementing regulations at 40 CFR part 60, subpart Ba.[337] After the EPA establishes the BSER in the final EG, as described in preamble sections XI and XII, each State that includes a designated facility must develop, adopt, and submit to the EPA its State plan under CAA section 111(d). The EPA then must determine whether to approve or disapprove the plan. If a State does not submit a plan, or if the EPA does not approve a State's plan, then the EPA must establish a Federal plan for the State.

Each of these steps, and more, is discussed in detail in this section which is organized into six parts. First, we discuss the components of the EG. Second, we discuss establishing standards of performance in State plans in response to a finalized EG. Third, we discuss the components of an approvable State plan submission. Fourth, we discuss the timing for State plan submissions and compliance times. Fifth, we discuss the EPA's action on State plans and promulgation of a Federal plan, if needed. Sixth, we discuss the CAA section 111(d) process as it relates to Tribes. 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. Components of EG

As previously described, CAA sections 111(d)(1) and 111(a)(1) collectively establish and define certain roles and responsibilities for the EPA and the States. The EPA addresses its responsibilities by drafting and publishing EG in accordance with 40 CFR 60.22a, which ''[contain] information pertinent to control of the designated pollutant from designated facilities.'' Mirroring language included in CAA section 111(d)(1), the EPA's implementing regulations define a designated pollutant as ''any air pollutant, the emissions of which are subject to a standard of performance for new stationary sources, but for which air quality criteria have not been issued and that is not included on a list published under section 108(a) or section 112(b)(1)(A) of the Act.'' 40 CFR 60.21a(a). The EPA's implementing regulations also define a designated facility as ''any existing facility (see § 60.2) which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility (see § 60.2).'' *Id.* at § 60.21a(b). The designated pollutant for purposes of the draft EG included in this proposal is GHGs, but the presumptive standards in the EG are expressed in terms of limitations on methane. A description of each of the designated facilities included in the draft EG can be found above in preamble sections XI and XII.

More specifically, 40 CFR 60.22a(b) lists six components to be included in EG to provide information for development of the State plans triggered by the promulgation of the EG. First, EG must include information regarding the ''endangerment of public health or welfare caused, or contributed to, by the designated pollutant.'' 40 CFR 60.22a(b)(1). Information on the harmful public health and welfare impacts of methane emissions from the oil and natural gas industry are included above in section III of this document. Second, the EG must include a ''description of systems of emission reduction which, in the judgment of the Administrator, have been adequately demonstrated.'' 40 CFR 60.22a(b)(2). The EPA has included such a description above in sections XI and XII of this preamble, and the NSPS OOOOb and EG TSD located at Docket ID No. EPA–HQ–OAR–2021–0317.

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[334] USGS. Hydraulic Fracturing. *https://www.usgs.gov/mission-areas/water-resources/science/hydraulic-fracturing?qt-science_center_objects=0#qt-science_center_objects.* Accessed September 1, 2021.

[335] See ''Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 FR 12022 (March 1, 1977); ''Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,'' 42 FR 55796 (October 18, 1977); ''Kraft Pulp Mills, Notice of Availability of Final Guideline Document,'' 44 FR 29828 (May 22, 1979); ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26294 (April 17, 1980); ''EG and Compliance Times for Municipal Solid Waste Landfills,'' 81 FR 59276 (August 29, 2016). In addition, EPA regulated mercury from coal-fired electric power plants in a 2005 rule that was vacated by the D.C. Circuit, ''Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units; Final Rule,'' 70 FR 28606 (May 18, 2005) (Clean Air Mercury Rule), vacated by *New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008). EPA also regulated GHG from fossil fuel-fired electric power plants in a 2015 rule that EPA subsequently repealed and replaced with a 2019 rule that, in turn, was vacated by the D.C. Circuit. ''Carbon Pollution EG for Existing Stationary Sources: Electric Utility Generating Units; Final Rule,'' 80 FR 64662 (Oct. 23, 2015) (Clean Power Plan), repealed and replaced by ''Repeal of the Clean Power Plan; EG for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to EG Implementing Regulations,'' 84 FR 32520 (July 8, 2019) (Affordable Clean Energy Rule), vacated by *Am. Lung Assoc.*

[336] See, *e.g.,* ''Standards of Performance for New Stationary Sources and EG for Existing Sources: Sewage Sludge Incineration Units, Final Rule,'' 76 FR 15372 (March 21, 2011).

[337] As previously noted, the D.C. Circuit has vacated certain timing provisions within subpart Ba. *Am. Lung Assoc.* v. *EPA.* However, the court did not vacate the applicability provision, and therefore Subpart Ba applies to any EG that EPA finalizes from this proposal.

Third, the EG must include information regarding ''the degree of emission limitation'' achievable through application of each system, along with information ''on the costs, non-air quality health environmental effects, and energy requirements of applying each system to designated facilities.'' 40 CFR 60.22a(b)(3). The EPA has included such a description in sections XI and XII of this preamble, and the NSPS OOOOb and EG TSD located at Docket ID No. EPA–HQ–OAR–2021–0317. Fourth, the EG must include information regarding the amount of time that the EPA believes would be normally necessary for designated facilities to design, install, and startup the control systems identified in component number three. See 40 CFR 60.22a(b)(4). The EPA explains how it proposes to address this component below in section XIV.E. Fifth, and likely most helpful to States when developing their plans in response to the final EG, the EG must include information regarding the ''degree of emission limitation achievable through the application of the best system of emission reduction'' that has been adequately demonstrated, taking into account the same factors as described in component three (cost, non-air quality health and environmental impact and energy requirements), ''and the time within which compliance with standards of performance can be achieved.'' 40 CFR 60.22a(b)(5). The EPA has included such information in sections XI and XII of this preamble and the NSPS OOOOb and EG TSD located at Docket ID No. EPA–HQ–OAR–2021–0317 as well as in section XIV.E of this preamble. In identifying the degree of achievable emission limitation, the EPA may subcategorize, that is to ''specify different degrees of emission limitation or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.'' *Id.* The EPA can choose to exercise that discretion to subcategorize within the draft EG for certain emission points. Sixth, and last, the EG is to include any other information not contemplated by the five other components that the EPA ''determines may contribute to the formulation of State plans.'' This section includes such information and guidance specifically designed to assist States in developing their plans under CAA 111(d) for these draft EG.

C. Establishing Standards of Performance in State Plans

While the EPA has the authority and responsibility to determine the BSER and the degree of limitation achievable through application of the BSER, CAA section 111(d)(1) provides that States shall submit to the EPA plans that establish standards of performance for designated facilities (*i.e.,* existing sources) and provide for implementation and enforcement of such standards. In light of the statutory text, and as reflected in the technical completeness criteria in the EPA's implementing regulations (explained below), State plans implementing the EG should include requirements and detailed information related to two key aspects of implementation: establishing standards of performance for designated facilities and providing measures that implement and enforce such standards.

Establish Standards of Performance for Designated Facilities. As an initial matter, a State must identify existing facilities within its borders that meet the applicability requirements in the final EG and are thereby considered a ''designated facility'' under the EG.[338] Then, States are required to establish standards of performance for the identified designated facilities. There is a fundamental requirement under CAA section 111(d) that a State's standards of performance reflect the degree of emission limitation achievable through the application of the BSER, which derives from the definition of ''standard of performance'' in CAA section 111(a)(1). The statute further requires the EPA to permit States, in applying a standard of performance, to consider a source's remaining useful life and other factors. Accordingly, based on both the mandatory and discretionary aspects of CAA section 111(d), a certain level of process is required of State plans: namely, the standards of performance must reflect the degree of emission limitation achievable through application of the BSER, and if the State chooses, the consideration of remaining useful life and other factors in applying a standard of performance to a designated facility.

For this 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 of performance that States may use in the development of State plans for specific emission points. The EPA believes that the presumptive standards of performance included in the EG will provide States with the level of stringency that the EPA would require to approve a State plan. Put another way, the EPA is choosing to format this EG such that if a State chooses to adopt the presumptive standards as the standards of performance in their State plan, then the EPA believes that such plan could be approved as meeting the requirements of CAA section 111(d) and the finalized EG, assuming the plan meets all other applicable requirements. In this way, the presumptive standards included in the EG serve a similar purpose as a model rule because they are intended to assist States in developing their plan submissions by providing the States with a starting point for their standards that are based on general industry parameters and assumptions. The EPA believes that providing these presumptive standards of performance will create a streamlined approach for States in developing plans and for the EPA in evaluating State plans. Of course, the EPA cannot pre-determine the outcome of a future rulemaking process, and inclusion of these presumptive standards in this EG does not impact the rulemaking process associated with the EPA's review of, and action on, a State plan submission. In its review of State plans, the EPA will consider the information in the final EG (including what EPA publishes in the final EG as the presumptive standards), as well as information submitted by the State and the public. The EPA will evaluate the approvability of all plans through individual notice-and-comment rulemaking processes.

As described in sections XI and XII, the EPA is proposing to translate the degree of emission limitation achievable through application of the BSER into presumptive standards for the following designated facilities as shown in Table 20.

[338] In accordance with 40 CFR 60.23a(b), states without any designated facilities are directed to submit to the Administrator a letter of negative declaration certifying that there are no designated facilities, as defined by EPA's emissions guidelines, located within the state. No plan is required for states that do not have any designated facilities.

TABLE 20—SUMMARY OF PROPOSED EG SUBPART OOOOC PRESUMPTIVE NUMERICAL STANDARDS

Designated facility	Proposed presumptive mass-based standards in the draft emissions guidelines for GHGs
Storage Vessels: Tank Battery with PTE of 20 tpy or More of Methane.	95 percent control.
Pneumatic Controllers: Natural Gas Driven that Vent to the Atmosphere.	VOC and methane emission rate of zero.
Wet Seal Centrifugal Compressors	95 percent control.
Pneumatic Pumps: Natural Gas Processing Plants	Zero natural gas emissions from diaphragm and piston pneumatic pumps.
Pneumatic Pumps: Locations Other Than Natural Gas Processing Plants.	95 percent control of diaphragm pneumatic pumps if there is an existing control or process on site. 95 percent control not required if (1) routed to an existing control that achieves less than 95 percent or (2) it is technically infeasible to route to the existing control device or process.
Associated Gas from Oil Wells	Route associated gas to a sales line. In the event that 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 control.

For these designated facilities, State plans would generally be expected to establish standards of performance that reflect these numerical presumptive standards, if included in the final EG. Further, for these designated facilities, the EPA is proposing to require that the standards of performance be expressed in the same form as the numerical presumptive standards set forth in Table 20. For example, for storage vessels that are part of a tank battery with a PTE of 20 tpy or more of methane, the EPA is proposing a numerical presumptive standard of 95-percent control. Accordingly, if finalized as proposed, States would be required to submit a plan that includes numerical standards of performance for these designated facilities expressed in the same form as the presumptive standard of 95 percent control. As described in this proposal and the associated supporting materials in the docket, the EPA has extensively and rigorously performed technical analyses in order to determine the appropriate proposed BSER for each set of designated facilities. The form of the numerical expression of the degrees of emission limitation achievable through application of the BSERs, and the associated presumptive standards, are a result of these technical analyses. The EPA believes that requiring States to maintain the same form of numerical standard in their plans will preserve the integrity of the BSERs and avoid analytic issues that are likely to arise if EPA is required to determine whether a different form of numerical standard submitted by a State has the same level of stringency as the final EG. Accordingly, having a uniform form of standard of performance will help streamline the States' development of their plans, as well as the EPA's review of those plans, since there will be fewer variables to evaluate in the development and review of each standard of performance. The EPA solicits comment on its proposal to require State plans to include numerical standards of performance for these designated facilities that are in the same form as the numerical presumptive standards, and whether EPA should additionally allow States to include a different form of numerical standards for these facilities so long as States demonstrate the equivalency of such standards to the level of stringency required under the final EG.

For the following designated facilities, the EPA is proposing to translate the degree of emission limitation achievable through application of the BSER into the presumptive standards shown in Table 21.

TABLE 21—SUMMARY OF PROPOSED EG SUBPART OOOOC PRESUMPTIVE NON–NUMERICAL STANDARDS

Designated facility	Proposed presumptive non-numerical standards in the draft emissions guidelines for GHGs
Fugitive Emissions: Well Sites—>0 to <3 tpy methane	Perform fugitive emissions survey and repair to demonstrate actual site emissions are reflected in calculation.
Fugitive Emissions: Well Sites—≥3 tpy methane	Quarterly OGI monitoring following appendix K. (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.
(Co-proposal) Fugitive Emissions: Well Sites—≥3 to <8 tpy methane.	Semiannual OGI monitoring following appendix K. (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.
(Co-proposal) Fugitive Emissions: Well Sites—≥8 tpy methane.	Quarterly OGI monitoring following appendix K. (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: Compressor Stations	Quarterly OGI monitoring following appendix K. (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 following appendix K. (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 bimonthly screening with advanced measurement technology and annual OGI monitoring following appendix K.
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).	Monitor and repair through fugitives program.
Reciprocating Compressors	Replace the reciprocating compressor rod packing based on annual monitoring (when measured leak rate exceeds 2 scfm) or route emissions to a process.
Equipment Leaks at Gas Plants	Bimonthly OGI LDAR program (NSPS VVa as optional alternative).

The EPA's implementing regulations at 40 CFR 60.24a(b) require that standards of performance shall either be based on allowable rate or limit of emissions, except when the EPA identifies cases in an EG where it would not be feasible to prescribe or enforce a rate or limit. Put another way, 40 CFR 60.24a(b) permits the EPA to identify cases where it is not feasible for States to prescribe or enforce a numerical standard, and in those cases the EPA can include non-numerical emissions limitations such as design, equipment, work practice, or operational standards, or a combination thereof, in the EG. See also definition of ''standard of performance'' in 40 CFR 60.21a(f). This authority in the context of the EG is akin to the EPA's authority under CAA section 111(h) to prescribe non-numerical standards where the Administrator determines it is not feasible to prescribe or enforce a numerical standard of performance. Where the EPA finalizes EG that authorize design, equipment, work practice, or operational standard, or a combination thereof, the State ''plan shall, to the degree possible, set forth the emission reductions achievable by implementation of such standards, and may permit compliance by the use of equipment determined by the State to be equivalent to that prescribed'' by the State plan. See 40 CFR 60.24a(b).

For the designated facilities listed in Table 21 the EPA has determined that it is not feasible to prescribe or enforce a numerical standard. As such, for these designated facilities, the EPA is proposing presumptive standards that are comprised of design, equipment, work practice, and/or operational standards. For these designated facilities, States are generally expected to establish the same non-numerical presumptive standards in Table 21. If States do not incorporate the presumptive standards included in the final EG into their State plan, but instead wish to utilize a different design, equipment, work practice, and/or operational standard for any of the designated facilities listed in Table 21, then the EPA is proposing to require that the State include in its plan a demonstration of how that standard will achieve a reduction in methane emissions at least equivalent to the reduction in methane emissions achieved by application of the presumptive standards included in the final EG. Such a demonstration should take into account, among other factors, the timelines for compliance. The EPA believes that this requirement is consistent with the AMEL provision in CAA section 111(h)(3), which requires a demonstration that any alternative ''will achieve a reduction in emissions . . . at least equivalent to the reduction in emissions'' achieved by EPA's standard, and the technical completeness criteria found at 40 CFR 60.27a(g)(3)(iv), which requires that State plans must include a ''demonstration that the State plan submittal is projected to achieve emissions performance under the applicable EG.''

To the extent that a State determines the presumptive standards in the final EG are not reasonable for a particular designated facility due to remaining useful life and other factors, the statute requires that the EPA's regulations under CAA section 111(d) permit States to consider such factors in applying a standard of performance. As such, the EPA's implementing regulations at 40 CFR 60.24a(e) allow States to consider remaining useful life and other factors to apply a less stringent standard of performance to a designated facility or class of facilities if one or more demonstrations are made. These demonstrations include 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 clarify that, absent such a demonstration, the State's standards of performance must be ''no less stringent than the corresponding'' EG. See 40 CFR 60.24a(c).

The EPA intends to provide further clarification on the general process and requirements for accounting for remaining useful life and other factors, including on the reasonableness aspect of the required demonstration, via a rulemaking to amend the implementing regulations in the near future. However, the EPA also recognizes that the oil and natural gas industry is unique such that the general approach to considering remaining useful life and other factors in the implementing regulations may not be an ideal fit. For example, the sheer number and variety of designated facilities in the oil and natural gas industry could make a source-specific (or even a class-specific) evaluation of remaining useful life and other factors extremely difficult and burdensome for States that want to undertake a demonstration. In addition, the presumptive standards for these designated facilities generally entail fewer major capital expenses compared with other industries for which EPA has previously issued EG under CAA section 111(d), and many of the proposed presumptive standards generally take the form of design, equipment, work practice, or operational standards rather than numerical emission limitations. Further, in proposing the presumptive standards for existing sources, the EPA has deliberately included certain flexibilities (*e.g.,* in cases of technical infeasibility) such that the EPA believes the presumptive standards should be achievable and cost-effective for a wide variety of facilities across the source category. Given these facts, the EPA believes that it would likely be difficult for States to demonstrate that the presumptive standards are not reasonable for the vast majority of designated facilities. The EPA is soliciting comment on these observations, and any other facts and circumstances that are unique to the oil and natural gas industry that could impact the remaining-useful-life-and-other-factors demonstration. The EPA is also soliciting comment as to whether the Agency should include specific provisions regarding the consideration of remaining useful life and other factors in this EG that would supplement or supersede the general provisions in the implementing regulations.

To the extent a State chooses to submit a plan that includes standards of performance that are more stringent than the requirements of the final EG, States have the authority to do so under CAA section 116, and the EPA has the authority to approve such plans and render them Federally enforceable if all applicable requirements are met. *Union Electric Co.* v. *EPA,* 427 U.S. 246, (1976). See also 40 CFR 60.24a(f). The EPA acknowledges that in the Affordable Clean Energy (ACE) rule, it previously took the position that *Union Electric* does not control the question of whether CAA section 111(d) State plans may be more stringent than Federal requirements. The ACE rule took this position on the basis that *Union Electric* on its face applies only to CAA section 110, and that it is potentially salient that CAA section 111(d) is predicated on specific technologies whereas CAA section 110 gives States broad latitude in the measures used for attaining the National Ambient Air Quality Standards (NAAQS). 84 FR 32559–61 (July 8, 2019). The EPA no longer takes this position. Upon further evaluation, the EPA believes that because of the structural similarities between CAA sections 110 and 111(d), CAA section 116 as interpreted by *Union Electric* requires the EPA to approve CAA section 111(d) State plans that are more stringent than required by the EG if the plan is otherwise is compliance with all applicable requirements. *See FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502 (2009). The D.C. Circuit in *Union Electric* rejected a construction of CAA sections 110 and 116 that measures more stringent than those required to attain the NAAQS cannot be approved into a federally enforceable State Implementation Plan (SIP) but must be adopted and enforced only as a matter of State law. *Id.* at 263–64. While the BSER and the NAAQS are distinct from one another in that the former is technology-based and the latter is based on ambient air quality, both CAA sections 111(d) and 110 are structurally similar in that States must adopt and submit to the EPA plans which include requirements to meet the objectives of each respective section. Requiring States to enact and enforce two sets of standards, one that is a federally approved CAA section 111(d) plan and one that is a stricter State plan, runs directly afoul of the court's holding that there is no basis for interpreting CAA section 116 in such manner. Therefore, the EPA interprets CAA sections 111(d) and 116 as allowing States to include, and the EPA to approve, more stringent standards of performance in State plans. The EPA notes that its authority is constrained to approving measures which comport with applicable statutory and regulatory requirements. For example, CAA section 111(d) only contemplates that State plans include requirements for designated facilities, therefore the EPA believes it does not have the authority to approve and render federally enforceable measures on other entities.

The EPA is also aware that in the context of regulating the oil and natural gas industry many States have existing programs they may want to leverage for purposes of satisfying their CAA section 111(d) State plan obligations. The EPA anticipates providing information on ways in which State plans can accommodate existing State programs to the extent such programs are at least as stringent as the requirement of the final EG. Consistent with the proposed presumptive standards, the EPA proposes that a State plan which relies on an existing State program must still establish standards of performance that are in the same form as the presumptive standards. The EPA solicits comment on whether States relying on existing 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 proposes 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 existing 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 existing State programs are at least as stringent as the requirements of the final EG. The EPA notes 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 an existing 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 also solicits comment on various ways in which existing State programs can be adopted into State plans. Particularly, the EPA is interested in how existing 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).

Providing Measures that Implement and Enforce Such Standards. As part of establishing standards of performance, State plans must also include compliance schedules for those standards. See 40 CFR 60.24a(a). Section XIV.E, explains how the EPA is proposing to approach compliance schedules. The EPA's implementing regulations require that, except where the State chooses to account for remaining useful life and other factors, State plans shall require final compliance as expeditiously as practicable, but no later than the compliance times specified in the EG. See 40 CFR 60.24a(c). Where a State applies a less stringent standard of performance because of remaining useful life and other factors, the compliance schedule must appropriately comport with that standard.[339]

In addition to establishing standards of performance and compliance schedules, State plans must also include, adequately document, and demonstrate the methods employed to implement and enforce the standards of performance such that the EPA can review and identify measures that assure transparent and verifiable implementation. As part of ensuring that regulatory obligations appropriately meet statutory requirements such as enforceability, the EPA has historically and consistently required that obligations placed on sources be quantifiable, non-duplicative, permanent, verifiable, and enforceable. See 40 CFR 60.27a(g)(3)(vi). In accordance with the EPA's implementing regulations, standards of performance required for designated facilities as part of a State plan to implement the EG proposed here must be non-duplicative, permanent, verifiable, and enforceable. The EPA acknowledges that it may not be feasible to quantify certain non-numerical standards of performance included in the EG. As such, the EPA is proposing that standards of performance for this EG be quantifiable to the extent feasible. A State plan implementing the EG should include information adequate to support a determination by the EPA that the plan meets these requirements. Additionally, States must include appropriate monitoring, reporting, and recordkeeping requirements to ensure that State plans adequately provide for the implementation and enforcement of standards of performance. For designated facilities where the EPA's presumptive standards include associated monitoring, reporting, and/or recordkeeping requirements, the EPA has determined that such requirements are necessary to ensure compliance. Thus, for those designated facilities, the EPA is proposing to require that the standards of performance established by States maintain the same monitoring, reporting, and recordkeeping requirements, or equivalent requirements. For example, the EG's presumptive standards for fugitives monitoring at well sites includes requirements for owners and operators to maintain records and submit reports that demonstrate compliance with the monitoring and repair provisions. As such, the EPA is proposing that the portion of the State plan which

[339] 40 CFR 60.24a(d) additionally required state plans to include increments of progress for any compliance schedule that extended more than 24 months after the state plan submittal date. While the substantive requirement for increments of progress was not challenged and remains effective, the timing aspect of this provision was vacated by the D.C. Circuit. *Am. Lung Assoc.,* 985 F.3d at 991. The EPA intends to address the timing aspect of this provision in the near future.

establishes standards of performance for that designated facility also includes requirements for owners and operators to maintain records and submit reports that demonstrate compliance with the monitoring and repair provisions. Where a State plan adopts standards of performance that 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. 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.

Emissions Inventories. The implementing regulations at 40 CFR 60.25a contain generally applicable requirements for emission inventories, source surveillance, and reports. State plans must include provisions to meet these requirements as well. Section 60.25a further specifies 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. Typically, the EPA would expect that State plans would present this information on a source-specific or unit-specific level. However, the EPA recognizes that due to the very large number of existing oil and natural gas sources,[340] and the frequent change of configuration and/or ownership, 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 is soliciting comment on whether to supersede the requirements of 40 CFR 60.25a(a) for purposes of this EG. 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). Specially, for the reasons explained previously, the EPA believes that in this context it could be difficult for the State plans to include ''an inventory of all designated facilities, including emission data for the designated pollutants and information related to emissions as specified in appendix D to this part'' as required by the first sentence in 40 CFR 60.25a(a). The EPA understands that States may not have such an inventory of all designated facilities already available and that creating such an inventory could be resource intensive. Likewise, the EPA understands that States may not have site-specific emissions data for each designated facility, and that creating such an inventory could also be very resource intensive. The EPA does not believe that such detailed information 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. Therefore, in order to avoid the potential burden that could be imposed by applying 40 CFR 60.25a(a) as written to this EG, the EPA is soliciting comment on whether the Agency should supersede the requirements of 40 CFR 60.25a(a) for purposes of this EG, and replace that requirement with a different emissions inventory requirement that seeks to represent the same general type of information but allows States to utilize existing inventories and emissions data. An example of an inventory that could be leveraged, and on which the EPA specifically solicits comment, is the GHGRP. The EPA envisions a superseding requirement that would not impose such a resource intensive burden on States by allowing use of an inventory of GHG emissions data and operational data for designated facilities during the most recent calendar year for which data is available at the time of State plan development and/or submission. The emissions inventory data submitted for this purpose could be derived from the GHGRP, and/or other available existing inventory information available to the State. The EPA recognizes that in this situation the facility definitions used for purposes of compiling the emissions inventory data might not be fully aligned with the designated facilities in the EG, and that it is possible that there could be designated facilities under this EG that are not required to report under the emissions inventory program being relied upon. Further, the EPA recognizes that the GHGRP may include a reporting threshold and/or utilize emission factors in a different manner than the EG. The EPA solicits comment on whether it is appropriate to utilize or supersede 40 CFR 60.25a(a) for purposes of this EG. Specifically, the EPA solicits comment on the practicality of States compiling an inventory for all designated facilities and on what reasonable alternatives may be more practical.

Meaningful Engagement. 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 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 State plan development is critical to ensuring that these impacts are fully considered. The EPA is proposing and soliciting comment on requiring States to perform outreach and meaningful engagement with overburdened and underserved communities during the development process of their State plan pursuant EG OOOOc.

States often rely primarily on public hearings as the foundation of their public engagement in their State plan development process because a public hearing is explicitly required pursuant to the applicable regulations. The existing provisions in subpart Ba (40 CFR 60.23a(c)–(f)) detail the public participation requirements associated with the development of a CAA section 111(d) State plan. Per these implementing regulations, States must provide certain notice of and conduct one or more public hearings on their State plan before such plan is adopted and submitted to the EPA for review and action. However, robust and meaningful public involvement in the development of a State plan should go beyond the minimum requirement to hold a public hearing. Meaningful engagement should include ensuring that States share information with and solicit input from stakeholders at critical junctures during plan development, which helps ensure that a plan is adequately addressing the potential impacts to public health and welfare that are the core concern of CAA section 111.

This early engagement is especially important for those stakeholders and communities directly impacted by the GHG emissions from designated facilities within the Crude Oil and Natural Gas source category being addressed in a State plan developed pursuant the EG OOOOc. As reflected in section VI and VII of the preamble, engagement with stakeholders and in particular adjacent communities was key during the development of the proposed NSPS and EG and will be key in the development of corresponding State plans that achieve the intended emission reductions and provide benefits to these communities. In

[340] 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.

recognizing that minority and low-income populations often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways to protect them from adverse public health and environmental effects of air pollution emitted from sources within the Oil and Natural Gas Industry that are addressed in this proposed rulemaking. For these reasons, the EPA is proposing to include an additional requirement associated with the adoption and submittal of State plans pursuant to EG OOOOc (in addition to the current requirements of Subpart Ba) by requiring States to meaningfully engage with members of the public, including overburdened and underserved communities, during the plan development process and prior to adoption and submission of the plan to the EPA.

The EPA's authority for proposing to include an additional requirement for meaningful engagement is provided by the authority of both CAA sections 111(d) and 301(a)(1). Under CAA section 111(d), one of the EPA's obligations is to promulgate a process "similar" to that of CAA section 110 under which States submit plans that implement emission reductions consistent with the BSER. CAA section 110(a)(1) requires States to adopt and submit State implementation plans (SIPs) after "reasonable notice and public hearings." The Act does not define what constitutes "reasonable notice" under CAA section 110, and therefore the EPA may reasonably interpret this requirement in promulgating a process under which States submit section 111(d) plans. The EPA proposes to give the "reasonable notice" requirement additional and separate meaning from the "public hearing" requirement. Therefore, in addition to the generally applicable public participation requirements in 40 CFR 60.23a(c)–(f) (which presently only require public notification of a public hearing), the EPA proposes to promulgate these additional meaningful engagement requirements within the EG OOOOc to ensure that the public has reasonable notice of relevant information and the opportunity to participate in the State plan development throughout the process. 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 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.

The proposed meaningful engagement requirements for State plan development would ensure that the process is inclusive, effective, and accessible to all. For this reason, the process must not be disproportionate or favor certain stakeholders. During the development of the State plan pursuant to EG OOOOc, the EPA expects States to identify any underserved or overburdened communities potentially impacted by the State plan. If any communities are identified, States should engage with these communities and develop public participation strategies to overcome linguistic, cultural, institutional, geographic, and other barriers to meaningful participation and ensure meaningful community representation in the process, recognizing diverse constituencies within any particular community. Community participation should occur as early as possible if it is to be meaningful. Meaningful engagement includes targeted outreach to underserved and overburdened communities, sharing information, and soliciting input on State plan development and on any accompanying assessments. The EPA uses the term "underserved" to mean populations sharing a particular characteristic, as well as geographic communities, that have been systemically denied a full opportunity to participate in aspects of economic, social, and civic life, and the term "overburdened" in referring to minority, low-income, Tribal, and indigenous populations or communities in the U.S. that potentially experience disproportionate environmental harms and risks as a result of greater vulnerability to environmental hazards . This increased vulnerability may be attributable to an accumulation of both negative and lack of positive environmental, health, economic, or social conditions within these populations or communities. This engagement will help ensure that State plans achieve meaningful emission reductions, that overburdened communities partake in the benefits and gains of the State plan, and that these communities are protected from being adversely impacted by the State plan. The EPA recognizes that emissions from designated sources could cross State borders, and therefore may affect underserved and overburdened communities in neighboring States. The EPA is soliciting comment on how meaningful engagement should apply to communities outside of the State that is developing a State plan, for example if a State should coordinate with the neighboring State for outreach or directly contact the affected community.

In sections VI and VII of this preamble the EPA addresses environmental justice considerations, implications, and stakeholder outreach the agency is taking to help ensure vulnerable communities are not disproportionately impacted by this rule. The considerations, analyses, and outreach presented in these preamble sections could help States in designing, planning, and developing their own outreach and engagement plans associated with the development and implementation of their State plans to reduce emissions of GHGs from designated facilities within the Crude Oil and Natural Gas source category.

To ensure that robust and meaningful public engagement process occurs as the States develop their CAA 111(d) plans, the EPA is also proposing to include a requirement within EG OOOOc for States to demonstrate in their plan submittal how they provided meaningful and timely engagement with all pertinent stakeholders, including, as necessary, industries and small businesses, as well as low-income communities, communities of color, and indigenous populations living near the designated facilities and who may be otherwise potentially affected by the State's plan. The State would be required to describe, in their plan submittal, the engagement they had with their stakeholders, including their overburdened and underserved communities. Additionally, the EPA would evaluate the States' demonstrations regarding meaningful public engagement as part of its completeness evaluation of a State plan submittal. If a State plan submission does not meet the required elements for public participation, including requirements for meaningful engagement, this may be ground for the EPA to find the submission incomplete or to disapprove the plan.

The EPA further notes that the implementing regulations allow a State to request the approval of different State procedures for public participation pursuant 40 CFR 60.23a(h). The EPA proposes to require that such alternate State procedures do not supersede the meaningful engagement requirements being proposed within EG OOOOc, so that a State would still be required to comply with the meaningful participation requirements even if they apply for a different procedure than the other public notice and hearing requirements under 40 CFR 60.23a. As provided in 40 CFR 60.23a(h), the EPA is proposing that States may also 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 within EG OOOOc, in fact provide for adequate notice to and meaningful participation of the public.

D. Components of State Plan Submission

Under CAA section 111(d)(2), the EPA has an obligation to determine whether each State plan is ''satisfactory.'' Therefore, in addition to identifying the components that the EG must include, the EPA's implementing regulations for CAA section 111(d) identify additional components that a State plan must include. Many of these requirements are found in 40 CFR 60.23a, 60.24a, 60.25a, and 60.26a. These provisions include requirements for components such as the following: Procedures a State must go through for adopting a plan before submitting it to the EPA; the stringency of standards of performance and compliance timelines; emission inventories, reporting, and recordkeeping; and, the legal authority a State must show in adopting a plan. These requirements are also generally contained in a list of required State plan elements, referred to as the State plan completeness criteria, found at 40 CFR 60.27a(g)(2)–(3). If the EPA determines that a submitted plan does not meet these criteria then the State is treated as not submitting a plan and the EPA has a duty to promulgate a Federal plan for that State. See CAA section 111(d)(2)(A) and 40 CFR 60.27a(g)(1). If the EPA determines a plan submission is complete, such determination does not reflect a judgment on the eventual approvability of the submitted portions of the plan, which instead must be made through notice-and-comment rulemaking. The completeness criteria do not apply to States without any designated facilities because these States are directed to submit to the Administrator a letter of negative declaration certifying that there are no designated facilities, as defined by the EPA's emissions guidelines, located within the State. See 40 CFR 60.23a(b). No plan is required for States that do not have any designated facilities. Designated facilities located in States that mistakenly submit a letter of negative declaration would be subject to a Federal plan until a State plan regulating those facilities becomes approved by the EPA.

The EPA established nine administrative and six technical criteria for complete State plans under CAA section 111(d). See 40 CFR 60.27a(g)(2)–(3). If a State plan does not include even one of these criteria, then the State plan may be deemed incomplete by the EPA. States that are familiar with the SIP submittal process under CAA section 110 will be familiar with the completeness criteria found in 40 CFR part 51, appendix V. While the completeness criteria for State plan submittals found at 40 CFR 60.27a(g)(2)–(3) is somewhat similar to the SIP submittal criteria in appendix V, it is not exactly the same. As such, even States that are familiar with the SIP submittal process under CAA section 110 are strongly encouraged to review the completeness criteria in 40 CFR 60.27a(g)(2)–(3) as well as the other State plan requirements found in 40 CFR 60.23a, 60.24a, 60.25a, and 60.26a early in their planning process.

In short, the administrative completeness criteria require that the State's plan include a formal submittal letter and a copy of the actual State regulations themselves, as well as evidence that the State has legal authority to adopt and implement the plan, actually adopted the plan, followed State procedural laws when adopting the plan, gave public notice of the changes to State law, held public hearing(s) if applicable, and responded to State-level comments. For a detailed description regarding the public hearing requirement, see 40 CFR 60.23a. For a detailed description of what the State plan must include in terms of evidence that the State has legal authority to adopt and implement the plan, see 40 CFR 60.26a. States are strongly encouraged to review the State plan requirements included in 40 CFR 60.23a and 60.26a in conjunction with the administrative completeness criteria in 40 CFR 60.27a.

The technical criteria require that the State's plan identify the designated facilities, the standards of performance, the geographic scope of the plan, monitoring, recordkeeping and reporting requirements (both for facilities to ensure compliance and for the State to ensure performance of the plan as a whole), and compliance schedules. The technical criteria further require that the State demonstrate that the plan is projected to achieve emission performance under the EG and that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable. As previously described, it may not be feasible to quantify certain non-numerical standards of performance. The EPA is proposing to require States demonstrate that each standard of performance is quantifiable, as feasible. For a detailed description of the State plan requirements regarding standards of performance, see section XIV.C and 40 CFR 60.24a.

In addition to these technical criteria, 40 CFR 60.25a(a) requires that State plans include certain emissions data for the designated facilities. As explained previously, the EPA is soliciting comment on superseding that requirement for this EG. Further, § 60.25a provides a detailed description of what the State plan is required to include in terms of certain compliance monitoring and reporting. States are strongly encouraged to review the State plan requirements included in 40 CFR 60.24a and 60.25a in conjunction with the technical completeness criteria in 40 CFR 60.27a.

E. Timing of State Plan Submissions and Compliance Times

The EPA acknowledges that the D.C. Circuit has vacated certain timing provisions within 40 CFR part 60, subpart Ba. *Am. Lung Assoc.* v. *EPA,* 985 F.3d at 991 (DC Cir. 2021). These provisions include timing requirements for when State plans are due upon publication of a final EG, for EPA's action on a State plan submission, and for EPA's promulgation of a Federal plan. The Agency plans to undertake rulemaking to address the provisions vacated under the court's decision in the near future. At this time, the EPA is soliciting comment 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. We recognize that the public needs to have an opportunity to review and comment on the new timelines that will address these regulatory gaps, including in particular the timeline for State plan submission, and the Agency is committed to publishing this proposed timeline for comment when available.

In accordance with 40 CFR 60.22a(b)(5), the EPA's EG is to provide information for the development of State plans that includes, among other things, ''the time within which compliance with standards of performance can be achieved.'' The EPA is proposing those compliance times for comment. See 40 CFR 60.25a(c). Each State plan must 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 their 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 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 two years following the State plan submittal deadline. As explained above, the EPA anticipates proposing a State plan submission deadline in a separate document. The EPA believes that two years 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. However, the EPA recognizes that there are many existing sources in the oil and natural gas industry that would be subject to a State plan if the presumptive standards are finalized in a similar manner as proposed in this document, and that there may be a wide range of configurations that may be present at any given facility. Further, the EPA recognizes that it may be appropriate to require different compliance times for different designated facilities. For example, it may be appropriate to require one compliance schedule for reciprocating compressors and a different compliance schedule for storage vessels. There may not be a one-size-fits-all approach to compliance times that is appropriate for all designated facilities.

Accordingly, the EPA is soliciting comment on whether a two-year compliance schedule is appropriate for all designated facilities, or whether the EG should require a shorter or longer compliance schedule. The EPA is further soliciting comment on whether it would be appropriate to establish different compliance schedules for different designated facilities, and if so, what are the appropriate timelines for each designated facility. The EPA is soliciting comment on this matter to collect information that might inform different compliance timeline(s) that Agency may propose for comment in the future via a supplemental proposal.

F. EPA Action on State Plans and Promulgation of Federal Plans

While CAA section 111(d)(1) authorizes States to develop State plans that establish standards of performance and provides States with certain discretion in determining the appropriate standards, CAA section 111(d)(2) provides the EPA a specific oversight role with respect to such State plans. This latter provision authorizes the EPA to prescribe a Federal plan for a State ''in cases where the State fails to submit a satisfactory plan.'' The States must therefore submit their plans to the EPA, and the EPA must evaluate each State plan to determine whether each plan is ''satisfactory.'' The EPA's implementing regulations for CAA section 111(d) accordingly provide procedural requirements for the EPA to make such a determination. See 40 CFR 60.27a.

Upon receipt of a State plan, the EPA is first required to determine whether the State plan submittal is complete in accordance with the completeness criteria explained above. See 40 CFR 60.27a(g)(1). The EPA would then have a set period of time to act on any State plan that is deemed complete.[342] If the EPA determines that the State plan submission is incomplete, then the State will be treated as not having made the submission, and the EPA would be required to promulgate a Federal plan for the designated facilities in that State. Likewise, if a State does not make any submission then the EPA is required to promulgate a Federal plan. If the EPA does not make an affirmative determination regarding completeness of the State plan submission within a certain amount of time from receiving the State plan, then the submission is deemed complete by operation of law. *Id.*

If a State has submitted a complete plan, then the EPA is required to evaluate that plan submission for approvability in accordance with the CAA, EPA's implementing regulations, and the applicable EG. The EPA may approve or disapprove the State plan submission in whole or in part. See 40 CFR 60.27a(b). If the EPA approves the State plan submission, then that State plan becomes Federally enforceable. If the EPA disapproves the required State plan submission, in whole or in part, then the EPA is required to promulgate a Federal plan for the designated facilities in that State via a notice-and-comment rulemaking, and with an opportunity for public hearing. See 40 CFR 60.27a(c) and (f). In either scenario that would give rise to the EPA's duty to promulgate a Federal plan (a finding that a State did not submit a complete plan or a disapproval of a State plan), the EPA would not be required to promulgate the Federal plan if the State corrects the deficiency giving rise to the EPA's duty and the EPA approves the State's plan before promulgating the Federal plan. Requirements regarding the content of a Federal plan are included in 40 CFR 60.27a(e).

G. Tribes and the Planning Process 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. If a Tribe obtains approval and submits a TIP, the EPA will generally use similar criteria and follow similar procedures as those described above for State plans when evaluating the TIP submission, and will approve the TIP if appropriate. The EPA is committed to working with eligible Tribes to help them seek authorization and develop plans if they choose. Tribes that choose to develop plans will generally have the same flexibilities available to States in this process. If a Tribe does not seek and obtain the authority from the EPA to establish a TIP, the EPA has the authority to establish a Federal CAA section 111(d) plan for areas of Indian country where designated facilities are located. A Federal plan would apply to all designated facilities located in the areas of Indian country covered by the Federal plan unless and until the EPA approves an applicable TIP applicable to those facilities.

[341] As previously noted, the timing aspect of this provision was vacated by the D.C. Circuit. *Am. Lung Assoc.* v. *EPA,* 985 F.3d 914 at 991. The EPA intends to address the timing aspect of this provision in the near future.

[342] As explained above, the D.C. Circuit vacated the timing provisions regarding EPA's action on a state plan submission, and EPA's promulgation of a Federal plan. *Am. Lung Assoc.* v. *EPA,* 985 F.3d at 991. The Agency plans to undertake rulemaking to address the provisions vacated under the court's decision in the near future.

XV. Prevention of Significant Deterioration and Title V Permitting

In this section, the EPA is addressing how regulation of GHGs under CAA section 111 could have implications for other EPA rules and for permits written under the CAA PSD preconstruction permit program and the CAA title V operating permit program. The EPA is proposing to include provisions in the regulations that explicitly address some of these potential implications, consistent with our experience in prior rules regulating GHGs. The EPA included and explained the basis for similar provisions when promulgating 2016 NSPS OOOOa, as well as the 2015 subpart TTTT NSPS for electric utility generating units. See 81 FR 35823, 35871 (June 3, 2016); 80 FR 64509, 64628 (October 23, 2015). The discussion in these prior rule preambles equally applies to the oil and gas sources subject to NSPS OOOOb and EG OOOOc.

In summary, in light of the U.S. Supreme Court's decision in *Utility Air Regulatory Group* v. *Environmental Protection Agency,* 573 U.S. 302 (2014) (*UARG*), the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source (or modification thereof) for the purpose of PSD applicability. Certain portions of the EPA's PSD regulations (specifically, the definition of ''subject to regulation'') effectively ensure that most sources will not trigger PSD solely by virtue of their GHG emissions. *E.g.,* 40 CFR 51.166(b)(48)(iv), 52.21(b)(49)(iv).[343] However, the EPA's PSD regulations (specifically, the definition of ''regulated NSR pollutant'') provide additional bases for PSD applicability for pollutants that are regulated under CAA section 111. To address this latter component of PSD applicability, the EPA is proposing to add provisions within the subpart OOOOb NSPS and subpart OOOOc EG to help clarify that the promulgation of GHG standards under section 111 will not result in additional sources becoming subject to PSD based solely on GHG emissions, which would be contrary to the holding in *UARG.* These provisions will be similar to those in the 2016 NSPS OOOOa and other section 111 rules that regulate GHGs. *See, e.g.,* 40 CFR 60.5360a(b)(1)–(2), 60.5515(b)(1)–(2).

The EPA understands there are also concerns that if methane were to be subject to regulation as a separate air pollutant from GHGs, sources that emit methane above the PSD thresholds or modifications that increase methane emissions could be subject to the PSD program. To address this concern and for purposes of clarity, the EPA is proposing to adopt regulatory text within subpart OOOOb NSPS and subpart OOOOc EG to clarify that the air pollutant that is subject to regulation is GHGs, even though the standard is expressed in the form of a limitation on emission of methane. This language will be substantially similar to language found in, for example, the 2016 NSPS OOOOa and other rules. See, *e.g.,* 40 CFR 60.5360a(a), 60.5515(a).

For sources that are subject to the PSD program based on non-GHG emissions, the CAA continues to require that PSD permits satisfy the best available control technology (BACT) requirement for GHGs. Based on the language in the PSD regulations, the EPA and States may continue to limit the application of BACT to GHG emissions in those circumstances where a new source emits GHGs in the amount of at least 75,000 tpy on a CO_2 Eq. basis or an existing major source increases emissions of GHGs by more than 75,000 tpy on a CO_2 Eq. basis. See 40 CFR 51.166(b)(48)(iv), 52.21(b)(49)(iv). The proposed revisions to the regulatory text within subparts OOOOb NSPS and OOOOc EG will ensure that this BACT applicability level remains operable to sources of GHGs regulated under CAA section 111, as have similar revisions in prior rules. See, *e.g.,* 40 CFR 60.5360a(b)(1)–(2), 60.5515(b)(1)–(2). This proposed rule will not require any additional revisions to SIPs.

Regarding title V, the *UARG* decision similarly held that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source for the purpose of title V applicability. Promulgation of CAA section 111 requirements for GHGs will not result in the EPA imposing a requirement that stationary sources obtain a title V permit solely because such sources emit or have the potential to emit GHGs above the applicable major source thresholds.[344]

To be clear, however, unless exempted by the Administrator through regulation under CAA section 502(a), any source, including a ''non-major source,'' subject to a standard or regulation under section 111 is required to apply for, and operate pursuant to, a title V permit that ensures compliance with all applicable CAA requirements for the source, including any GHG-related applicable requirements. This aspect of the title V program is not affected by *UARG.*[345] The EPA proposes to include an exemption from the obligation to obtain a title V permit for sources subject to NSPS OOOOb and EG OOOOc, unless such sources would otherwise be required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a), as the EPA did in NSPS OOOO and OOOOa.[346] See 40 CFR 60.5370, 60.5370a. However, sources that are subject to the CAA section 111 standards promulgated in this rule and that are otherwise required to obtain a title V permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) will be required to apply for, and operate pursuant to, a title V permit that ensures compliance with all applicable CAA requirements, including any GHG-related applicable requirements.

XVI. 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 41 million short tons of methane emissions reductions (920 million tons CO_2 Eq.), 12 million short tons of VOC emissions reductions, and 480 thousand short tons of HAP emission reductions 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

[343] In 2016, the EPA proposed additional revisions to the PSD and title V regulations that would address these and other concerns. 81 FR 58110 (October 3, 2016).

[344] Additional regulatory text, based on that in prior rules, will further ensure that title V regulations are not applied to GHGs solely because they are regulated under CAA section 111. See, *e.g.,* 40 CFR 60.5360a(b)(3)–(4), 60.5515(b)(3)–(4). The EPA understands that concerns regarding the regulation of methane as a separate air pollutant (described with respect to PSD) also apply to title V. The EPA's proposed regulatory text—clarifying that the pollutant subject to regulation is GHGs—will similarly address these concerns with respect to title V. See, *e.g.,* 40 CFR 60.5360a(a), 60.5515(a).

[345] See Memorandum from Janet G. McCabe, Acting Assistant Administrator, Office of Air and Radiation, and Cynthia Giles, Assistant Administrator, Office of Enforcement and Compliance Assurance, to Regional Administrators, Regions 1–10, *Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in Utility Regulatory Group* v. *Environmental Protection Agency* (July 24, 2014) at 5.

[346] The EPA provided the rationale for exempting this source category from the title V permitting requirements during the rulemaking for the 2012 NSPS OOOO. See 76 FR 52737, 52751 (August 23, 2011). That rationale continues to apply to this source category.

did not estimate impacts after 2035 for reasons including limited information, as explained in the RIA.

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 XVI.D. 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 PV of the regulatory compliance cost associated with the proposed NSPS OOOOb and EG OOOOc over the 2023 to 2035 period was estimated to be $13 billion (in 2019 dollars) using a 3-percent discount rate and $10 billion using a 7-percent discount rate. The EAV of these cost reductions is estimated to be $1.2 billion per year using a 3-percent discount rate and $1.2 billion per year using a 7-percent discount rate.

These estimates do not, however, include the producer revenues associated with the projected increase in the recovery of saleable natural gas. Estimates of the value of the recovered product have been included in previous regulatory analyses as offsetting compliance costs. Using the 2021 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, the EPA estimated a PV of regulatory compliance costs of the proposed rule over the 2023 to 2035 period of $7.2 billion using a 3-percent discount rate and $6.3 billion using a 7-percent discount rate. The corresponding estimates of the EAV of compliance costs after accounting for the recovery of saleable natural gas were $680 million per year using a 3-percent discount rate and $760 million 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 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 249 million Mcf in 2026 (or about 0.8 percent of natural gas production) with a maximum price increase of $0.05 per Mcf (or about 1.8 percent). We estimated the maximum annual reduction in crude oil production would be about 12.2 million barrels (or about 0.3 percent of crude oil production) with a maximum price increase of about $0.06 per barrel (or less than 0.1 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 modelled 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.[347] 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 global social benefits of CH_4 emission reductions expected from this proposed rule using the SC–CH_4 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–CH_4 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–CH_4 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–CH_4 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

[347] Employment figure drawn from the Bureau of Labor Statistics Current Employment Statistics for NAICS code 211.

analyses of policies that affect CH_4 emissions.

The interim SC–GHG estimates 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 Technical Support Document (TSD): Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021), the EPA agrees that the interim SC–GHG estimates represent the most appropriate estimate of the SC–GHG until revised estimates have been developed reflecting the latest, peer-reviewed science.

The EPA estimated the PV of the climate benefits over the 2023 to 2035 period to be $55 billion at a 3-percent discount rate. The EAV of these benefits is estimated to be $5.2 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 B 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.

XVII. 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 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'', 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 OOOO and OOOOa, have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The information collection activities in the proposed rules for 40 CFR part 60, subparts OOOOb and OOOOc, will be submitted for approval to OMB under the PRA as part of a supplemental proposed rule.[348] The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2523.04. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

The final rule for this action will include updates to the CFR to reflect the disapproval of the 2020 Policy Rule that was effectuated by the joint resolution enacted pursuant to the CRA on June 30, 2021. The EPA is not soliciting comment on these updates. In addition, this rule proposes amendments to the 2016 NSPS OOOOa to address (1) certain resulting inconsistencies between the VOC and methane standards resulting from the CRA, and (2) rescind certain determinations made in the 2020 Technical Rule, with respect to fugitive emissions monitoring at low production well sites and gathering and boosting stations as they were not supported by the record for that rule, or by our subsequent information and analysis. The EPA is also proposing further amendments to its 2016 NSPS OOOOa to address technical and implementation issues.

This ICR reflects the EPA's proposed amendments to the 2016 NSPS OOOOa. 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.

The respondents are owners or operators of onshore oil and natural gas affected facilities (40 CFR 60.5365a). For the purposes of this ICR, it is assumed that oil and natural gas affected facilities located in the U.S. are owned and operated by the oil and natural gas industry, and that none of the affected facilities in the U.S. are owned or operated by State, local, Tribal or the Federal government. All affected facilities are assumed to be privately owned for-profit businesses.

The EPA estimates an average of 3,268 respondents will be affected by NSPS OOOOa over the three-year period (2021–2023). The average annual burden for the recordkeeping and reporting requirements for these owners and operators is 283,030 person-hours, with an average annual cost of $93,779,839 over the three-year period (2021–2023).

Respondents/affected entities: Oil and natural gas operators and owners.

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 3,268.

Frequency of response: Varies depending on affected facility.[349]

Total estimated burden: 283,030 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $93,779,839 (2019$), which includes no capital or O&M 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

[348] While not quantified in this proposal, the EPA anticipates the estimated ICR burden of proposed NSPS OOOOb and EG OOOOc to be at least as burdensome as NSPS OOOOa. The EPA anticipates some sources may have similar ICR burden to NSPS OOOOa. Examples of these include fugitive emissions from compressor stations, pneumatic controllers at gas processing, centrifugal compressors, pneumatic pumps, well completions, and sweetening units. The EPA anticipates other sources could have dissimilar burden to NSPS OOOOa because the standards are different or are brand new to this proposal. Examples of these include fugitive emissions from well sites, storage vessels, pneumatic controllers, reciprocating compressors, liquids unloading, and equipment leaks at gas plants.

[349] 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.

provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs via email to *OIRA_submission@omb.eop.gov,* Attention: Desk Officer for the EPA. 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 December 15, 2021. The EPA will respond to any ICR-related comments in the final rule.

C. Regulatory Flexibility Act (RFA)

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, a small entity is defined as: (1) A small business in the oil or natural gas industry whose parent company has revenues or numbers of employees below the SBA Size Standards for the relevant NAICS code; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Pursuant to section 603 of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) that examines 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 docket and is summarized here.

The IRFA describes the reason why the proposed rule is being considered and describes the objectives and legal basis of the proposed rule, as well as discusses related rules affecting the oil and natural gas sector. The IRFA describes the EPA's examination of small entity effects prior to proposing a regulatory option and provides information about steps taken to minimize significant impacts on small entities while achieving the objectives of the rule.

The EPA also summarized the potential regulatory cost impacts of the proposed rule and alternatives in Section 2 of the RIA. The analysis in the IRFA drew upon some of the same analyses and assumptions as the analyses presented in the RIA. The IRFA analysis is presented in its entirely in Section 4.3 of the RIA.

We estimated cost-to-sales ratios (CSR) for each small entity to summarize the impacts of the proposed rule on small entities. In the processing segment, we find that average compliance costs are expected to be negative, and no entity has a cost-to-sales ratio greater than either 1 percent or 3 percent. In the production segment, when expected revenues from natural gas product recovery are included, 101 small entities (7.2 percent) have cost-to-sales ratios greater than 1 percent, but none have cost-to-sales ratios greater than 3 percent. When expected revenues from natural gas product recovery are excluded, the number of small entities with cost-to-sales ratios greater than 1 percent increases to 331 (23 percent); about half of those small entities (11 percent) also have cost-to-sales ratios greater than 3 percent.

The analysis above is subject to a number of caveats and limitations. These are discussed in detail in the IRFA, as well as in Section 4.3 of the RIA. 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.

D. Unfunded Mandates Reform Act (UMRA)

The proposed NSPS and EG do not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and do not significantly or uniquely affect small governments. The proposed NSPS does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and Tribal governments, in the aggregate or the private sector in any one year. For projected cost estimates, see ''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'', which is available in the docket. The EG is proposed under CAA section 111(d) and does not impose any direct compliance requirements on designated facilities, apart from the requirement for States to develop State plans. As explained in section XIV.G., 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. The NSPS and EG action imposes no enforceable duty on any State, local, or Tribal governments or the private sector. 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. 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 does not have federalism implications. It will not have substantial direct effects on the

States, on the relationship between the Federal Government and the States, or on the distribution of power and responsibilities among the various levels of government.

The proposed EG OOOOc may have federalism implications because development of State plans may entail many hours of staff time to develop and coordinate programs for compliance with the proposed rule, as well as time to work with State legislatures as appropriate, and develop a plan submittal. The Agency understands that the EG may impose a burden on States and is committed to providing aid and guidance to States through the plan development process. In the spirit of E.O. 13132 and consistent with the EPA policy to promote communications between the EPA and State and local governments, the EPA specifically solicits comment on this proposed rule from State and local officials including information on costs associated with developing and submitting State plans in accordance with EG OOOOc.

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. 65 FR 67249 (November 9, 2000). 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 proposal does not directly impose specific requirements on designated facilities, including those located in Indian country, but before developing any standards for sources on Tribal land, the EPA would consult with leaders from affected Tribes.

Consistent with previous actions affecting the Crude Oil and Natural Gas source category, there is significant Tribal interest because of the growth of the oil and natural gas production in Indian country. Consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA will engage in consultation with Tribal officials during the development of this action.

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 finalize 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. The assessment literature since 2009 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience. 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 detailed information on the impacts of climate change to human health and welfare is provided in section III 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. To estimate the potential impacts of the proposed NSPS OOOOb and EG OOOOc on crude oil and natural gas production, the EPA developed a pair of single-market, static partial-equilibrium analyses of national crude oil and natural gas markets. These analyses are presented in the RIA for this action, which is in the public docket. We treat crude oil markets and natural gas markets separately in these models. The EPA estimated that the proposed rule could result in a maximum decrease in annual natural gas production of about 249 million Mcf in 2026 (or about 0.8 percent of natural gas production). We estimated the maximum annual reduction in crude oil production would be about 12.2 million barrels (or about 0.3 percent of crude oil production). 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 modelled market impacts for years after 2026 are smaller than the peaks estimated for 2026. As regulatory costs are projected to decline after 2026, the modelled market impacts for years after 2026 are smaller than the peaks estimated for 2026. The energy impacts the EPA estimates from these rules may be under- or over-estimates of the true energy impacts associated with this action. For more information on the estimated energy effects, please refer to the RIA for this rulemaking.

I. National Technology Transfer and Advancement Act (NTTAA)

This proposed action for NSPS OOOOb and EG OOOOc involves technical standards.[350] 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

[350] The EPA is not proposing changes to previously conducted searches for 40 CFR part 60, subparts OOOO and OOOOa. Therefore, this section only describes proposed NSPS OOOOb and EG OOOOc standards and searches.

(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 instructional 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'' in the public docket. The EPA plans to propose the regulatory language for NSPS OOOOb and EG OOOOc through a supplemental action. At that time, the EPA will include any appropriate incorporation by reference in accordance with requirements of 1 CFR 51.5 as discussed below. The EPA anticipates that the following ten standards would be incorporated 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, kerosines, 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 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 it they are available for purchase from the following addresses: American Society for Testing and Materials (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: *http://nepis.epa.gov/Adobe/PDF/P100EKJR.pdf.*

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that 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 decision is contained in the RIA prepared under E.O. 12866 for this proposal. In Section 4 of the RIA, the EPA presents a qualitative discussion of the climate impacts of GHGs and environmental justice. The section also presents a set of limited quantitative environmental justice analyses focused on the current distribution of VOC and HAP emissions from oil and natural gas sector. These analyses evaluated baseline scenarios and enabled us to characterize risks due to oil and natural gas VOC and HAP emissions prior to implementation of the proposed rule. These analyses potentially suggest that VOC and HAP emissions from the oil and natural gas sector may disproportionately impact vulnerable populations or overburdened communities under baseline scenarios; however, various uncertainties and data gaps remain, and should be taken into consideration when interpreting these results. Additionally, we lack key information that would be needed to characterize post-control risks under the proposed NSPS OOOOb and EG OOOOc or the regulatory alternatives analyzed in the RIA, preventing the EPA from analyzing spatially differentiated outcomes. While a definitive assessment of the impacts of this proposed rule on minority populations, low-income populations, and/or indigenous peoples was not performed, the EPA believes that this action will achieve substantial methane, VOC, and HAP emission reductions and will further improve environmental justice community health and welfare. The EPA believes that any potential environmental justice populations that may experience disproportionate impacts in the baseline may realize disproportionate improvements in air quality resulting from emission reductions.

In addition, the EPA provided the public, including those communities disproportionately impacted by the burdens of pollution, opportunities for meaningful engagement with the EPA on this action. A summary of outreach activities conducted by the Agency and what we heard from communities is provided in section VI of this preamble.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Reporting and recordkeeping requirements.

Michael S. Regan,

Administrator.

[FR Doc. 2021–24202 Filed 11–5–21; 4:15 pm]

BILLING CODE 6560–50–P