HARVARD LAW SCHOOL | ENVIRONMENTAL & ENERGY LAW PROGRAM

EPA's Supplemental Methane Proposal – A Comprehensive Regulatory Framework to Encourage Use of Advanced Technologies and Significantly Reduce Methane Emissions

By Carrie Jenks, Sara Dewey, and Hannah Oakes
November 21, 2022

At the UN climate conference in Egypt (COP27) on November 11, 2022, President Biden announced the release of EPA's Supplemental Proposal ("Supplemental") for cutting methane and volatile organic compounds (VOCs) from new facilities and methane from existing facilities in the oil and gas sector.[1] EPA projects that by 2030, the Supplemental will reduce methane emissions by 87 percent relative to 2005 levels while also recovering saleable natural gas.[2]

The Supplemental follows EPA's November 2021 proposed rule ("2021 Proposal"), in which EPA took an initial step to restore methane rules for oil and natural gas facilities that the Trump administration repealed; strengthen emissions requirements for oil and natural gas production; and extend coverage of these requirements to more kinds of equipment than were originally included in prior rules.[3] The 2021 Proposal also proposed, for the first time, to limit methane from existing oil and natural gas infrastructure. See our Regulatory Tracker and white paper on the 2021 Proposal for additional background on the 2021 Proposal and rollback by the Trump administration.

The Supplemental strengthens the 2021 Proposal and reflects stakeholder comments by proposing more comprehensive requirements to reduce emissions, an innovative leak detection technology-inclusive approach, and a program to quickly identify and repair the largest leak events. The Supplemental also introduces proposed regulatory text to implement these standards.

In this paper we focus on the Supplemental's approaches to enabling the timely deployment of rapidly advancing technologies. Deployment of these technologies can lead to greater emission reductions by detecting the larger events that are a significant portion of the sector's methane emissions. For example, EPA's proposed matrices would allow owners and operators to choose to use alternative monitoring technologies (e.g., aerial surveys, drone surveys, or continuous monitoring systems) that meet certain criteria. Additionally, EPA explains that its proposed "super-emitter response program" would serve as a "backstop" to monitor and respond to the largest leak events that contribute over 50 percent of the total emissions.[4]

We also discuss the deadlines EPA is proposing to require for state plans, the authority of states to include certain flexibilities, and how this interacts with other methane programs. If EPA finalizes the rule by mid-2023, most sources that are built or modified after November 15, 2021 must comply upon final rule publication, state plans for existing sources would be due in early 2025, and sources built before November 15, 2021 would need to comply by early 2028. Additionally, the Inflation Reduction Act's (IRA) methane fee would begin in 2024 and apply at least until methane emission Clean Air Act section 111(b) standards and 111(d) state plans "are in effect in all states with respect

---

[1] November 11, 2022 Supplemental proposed rule ("Supplemental"). The CAA directs regulation of existing sources of pollution that are not already addressed under sections 110 or 112 of the CAA and VOCs are regulated as a precursor to ozone under section 110.
[2] EPA estimates that between 2023 and 2035, the proposed regulations would recover $4.6 billion natural gas product, which will reduce the net compliance costs of the program. Supplemental, p. 39, Table 5.
[3] November 15, 2021 proposed rule ("2021 Proposal").
[4] Supplemental, p. 150.

to the applicable facilities" or if a facility's methane emissions do not exceed "0.20 percent of the natural gas sent to sale from the facility".[5]

Since this rule is a proposal, EPA requests additional feedback on many questions to enable the agency to refine the rule and finalize it in early 2023. Comments are due by **February 13, 2023.** These comments will inform EPA's final rule and ensure that the final rule drives emissions reductions, spurs advanced technologies, and is legally durable.

Overview of the Supplemental Proposal

EPA's Supplemental includes strengthened new source standards and new existing source standards that aim to reduce methane emissions from the oil and natural gas industry—the United States' largest industrial source of methane emissions. The Supplemental includes New Source Performance Standards (NSPS) under Clean Air Act (CAA) Section 111(b) for new, modified, and reconstructed sources, and Emissions Guidelines (EG) under CAA section 111(d) for states to develop plans for existing sources.[6]

EPA estimates the Supplemental will achieve $34 billion in net benefits from 2023[7] to 2035, or $3.2 billion annually (using a 3 percent discount rate).[8] This figure incorporates annual compliance costs of $1.8 billion, product recovery savings of $0.44 billion, and climate benefits of $4.5 billion.[9] To determine these estimates, EPA uses the social cost of methane in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order (EO) 13990 (IWG 2021) published in February 2021.[10] However, in a separate document, EPA also presents new estimates for the social costs of greenhouse gases that reflect recent scientific research and recommendations by incorporating three additional near-term discount rates (1.5, 2.0, and 2.5 percent) "based on multiple lines of evidence on observed market rates."[11] Importantly, EPA explains that its identification of the proposed standards based on the statutory term "best system of emission reduction" (BSER) and case law is entirely separate from its benefits assessment required under EO 12866 (Regulatory Planning and Review, 1993).[12]

---

[5] Inflation Reduction Act § 60113(f).
[6] EPA proposes to use the November 15, 2021 Proposal publication date as the cut off for defining "new" versus "existing" sources for most sources covered by the rule. EPA notes that while it received comments stating that the November 2021 Proposal's publication date should not be used to define new sources for purposes of the NSPS because it lacked regulatory text, EPA explains that the neither the CAA nor the Administrative Procedure Act explicitly state that regulatory text is required for notice for purposes of notice to define "new, modified, or reconstructed" sources provided the proposal includes "either the terms or substance of the proposed rule or a description of the subjects and issues involved". However, because EPA is proposing standards for dry seal centrifugal compressors for the first time in the Supplemental, EPA specifies that NSPS for dry seal centrifugal compressors will apply to those compressors that are built after the Supplemental's publication date. Supplemental, p. 47.
[7] EPA uses the initial analysis year in 2023 because it "assume[s] the proposed rule will be finalized early in 2023." *Id.* p. 35.
[8] Id. p. 39.
[9] Id.
[10] EPA estimates the climate benefits of methane emission reductions expected from the Supplemental using the social cost of methane estimates presented in the "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under EO 13990" (Feb. 2021) by the Interagency Working Group on the Social Cost of Greenhouse Gases and incorporates more recent research. *Id.* pp. 36-37.
[11] Supplementary Material for the Regulatory Impact Analysis for the Supplemental Proposed Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review": EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, pp. 1-3 (Sept. 2022). For more information, see our Regulatory Tracker on the Social Cost of Greenhouse Gases.
[12] Supplemental, p. 37.

EPA also projects that the Supplemental will achieve additional non-monetized benefits from 2023 to 2035 including: climate and ozone health benefits from reducing 36 million short tons of methane; $PM_{2.5}$ and ozone health benefits from reducing 9.7 million short tons of VOCs; hazardous air pollutants (HAP) health benefits from reducing 390 thousand short tons of HAP; climate benefits from emission reductions from the super-emitter response program; visibility benefits; and reduced negative vegetation effects.[13] EPA notes that the estimated emissions reductions may not fully characterize the reductions achieved by the rule as the assumptions may be conservative and not account for all super-emitter emissions events.

Key Requirements and Alternatives in EPA's Supplemental Proposal

In setting NSPS and EGs, the Clean Air Act requires EPA to determine the best system of emissions reduction.[14] Section 111(a)(1) requires that the standards of performance reflect the "degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impacts and energy requirements) the Administrator determines has been adequately demonstrated."[15]

EPA's Supplemental includes different standards for subcategories of the covered oil and gas facilities' equipment and process emission sources. The proposed standards include numerical emission standards, device requirements, and work practice standards such as requirements to monitor for and repair any identified leaks. For monitoring fugitive emissions, EPA proposes to require varying frequencies of audio, visual, and olfactory (AVO) inspections and optical gas imaging (OGI). However, EPA also proposes to allow operators to use a broader range of alternative advanced technologies that comply with certain detection thresholds within a matrix. EPA explains that the matrix approach provides "clear goals for vendors interested in the development of future technologies for methane detection" and proposes a process through which vendors can seek EPA's approval for site-specific, basin-specific, or sector-wide advanced technology use.[16]

EPA also proposes a new super-emitter response program and the Supplemental includes certain more stringent requirements for oil and natural gas equipment compared to the 2021 Proposal. We list the proposed NSPS for each source compared to the existing 2016 requirements and the 2021 Proposal in the Appendix.

Fugitive Emissions Monitoring

In the Supplemental, EPA proposes expanding routine fugitive emissions monitoring[17] to all oil and natural gas well sites, regardless of size or other characteristics, with flexibilities for those located on the Alaskan North Slope. While the 2021 Proposal excluded lower-producing (small) wells, the Supplemental adds a subcategory for small wells, and includes tiered requirements for all wells depending on the number of wells and level of production. The Supplemental also proposes that emissions monitoring continue for the entire life of the well site until it has been "closed, including

[13] Id. p. 39.
[14] For additional information on EPA's obligation for existing sources, see our blog on the 2021 Proposal.
[15] 42 U.S.C.A. § 7411(a)(1).
[16] Supplemental, p. 136.
[17] The definition of "fugitive emissions component" would now include yard piping and clarify that it does not include components that may be regulated elsewhere: "any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and CVS not subject to 40 CFR 60.5411b, thief hatches or other openings on a storage vessel not subject to 40 CFR 60.5395b, compressors, instruments, meters, and yard piping." *Id.* p. 116.

plugging the wells at the site and submitting a well closure report," to address concerns regarding orphaned wells and unplugged idled wells.[18]
Additionally, unlike the 2021 Proposal, which required owners and operators to conduct OGI monitoring according to a proposed Appendix K, EPA is now proposing that OGI surveys would follow the NSPS OOOOb regulatory requirements (40 CFR 60.5397b) or Method 21.[19]

In the Supplemental, EPA proposes to require certain monitoring frequency and detection methods (AVO or OGI) based on results the agency obtained using the Fugitive Emissions Abatement Simulation Toolkit (FEAST) modeling and updated cost assumptions. Table 1 lists EPA's proposed BSER for fugitive emissions at new and existing compressor stations and the four well categories. Super-emitters, another source of fugitive emissions, would be regulated under a separate program.

Table 1: Supplemental Proposed BSER for Fugitive Emissions at Compressor Stations and The Four Well Categories[20]

Source Category	**BSER**
Single wellhead only sites[21] and small well sites[22]	Quarterly AVO inspections
Multi-wellhead only sites with two or more wellheads	Quarterly AVO inspections AND Semiannual OGI (or Method 21)
Well sites and centralized production facilities with major production and processing equipment	Bimonthly AVO monitoring (i.e., every other month) AND Quarterly OGI (or Method 21)
Compressor Stations	Monthly AVO monitoring AND Quarterly OGI monitoring
Well Sites and Compressor Stations on the Alaska North Slope	Annual OGI (or Method 21)[23]

To conduct AVO and OGI monitoring, operators must walk around a physical location with a hand-held device, pointing it directly at regulated components to identify leaks. These inspections are labor-intensive and expensive relative to many advanced monitoring technologies and methods.[24] For these reasons, the Supplemental proposes an alternative matrix approach to allow use of rapidly developing emission detection technologies in a way that achieves greater emissions reductions cost effectively.

[18] Id. p. 113-15.
[19] Id. p. 72.
[20] Id. pp. 26-27 & 31-32.
[21] EPA proposes the following definition: "Wellhead only well site means, for the purposes of the fugitive emissions standards at §60.5397b, a well site that contains one or more wellheads and no major production and processing equipment." Supplemental, Subpart OOOOb §60.5430b.
[22] EPA proposes the following definition: "Small well site means, for purposes of the fugitive emissions standards in §§60.5397b and 60.5398b, a well site that contains a single wellhead, no more than one piece of certain major production and processing equipment, and associated meters and yard piping. Small well sites cannot include any controlled storage vessels (or controlled tank batteries), control devices, or natural gas-driven pneumatic controllers." *Id.*
[23] "Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart." Supplemental, Subpart OOOOb §60.5397b(g)(1)(v).
[24] K. Rashid, A. Speck, T.P. Osedach, D.V. Perroni, A.E. Pomerantz, Optimized Inspection of Upstream Oil and Gas Methane Emissions Using Airborne LiDAR Surveillance, Applied Energy 275 (2020) 115327.

Alternative Technology Matrices

As alternatives to the BSER in Table 1, the Supplemental includes matrices for periodic and continuous emissions screening with varying detection thresholds and monitoring frequency based on equivalency modeling.

EPA notes that it received "overwhelming support" for a matrix to enable advanced technology.[25] In the 2021 Proposal, EPA solicited feedback regarding an alternative to quarterly OGI fugitive emissions monitoring by discussing a matrix. For this 2021 matrix, EPA proposed bimonthly screening using technologies that a minimum detection threshold of 10 kg/hr coupled with annual OGI monitoring. EPA also sought feedback on whether such a matrix is well suited for continuous emission monitoring technologies even though these technologies may meet the minimum detection threshold. In response, commenters provided alternative minimum detection thresholds and monitoring frequencies, and supporting evidence for equivalency to the proposed BSER including results from LDAR program effectiveness models, such as FEAST modeling.

To develop the matrices included in the Supplemental and incorporate these comments, EPA used FEAST to "directly compare alternatives to the results of the OGI fugitive emissions programs proposed as BSER."[26] EPA is seeking comment on this modeling, including the "appropriateness of the inputs and assumptions used in the EPA's FEAST modeling simulations."[27]

Survey Matrix for Alternative Periodic Screening Approach

EPA explains in the Supplemental that "based on recent aerial and satellite studies" a primary advantage of frequent screening with advanced technologies is to quickly identify super-emitters.[28] For these screening technologies, EPA proposes two matrices "where the minimum detection threshold of the screening technology determines the frequency of screening surveys and whether an annual OGI ground-based survey is needed as a supplement to the periodic screening surveys."[29] The Supplemental includes five alternative minimum detection thresholds for the specified sources, setting frequency requirements combined with leak root cause analyses and corrective action response times depending on the nature of the leak. EPA notes that the proposed matrices "provide owners and operators who choose to implement the alternative periodic screening approach a wider selection of methane detection technologies from which to choose . . . [and] provide clear goals for vendors interested in the development of future technologies for methane detection."[30]

Tables 2 and 3 show the periodic survey matrices that apply to fugitive emissions components. EPA is explicitly seeking comments regarding the applicability of the matrices for available or currently under development technologies. EPA proposes one alternative periodic survey matrix to monitor facilities subject to quarterly OGI monitoring and a second alternative periodic survey matrix specifically for single and multi-wellhead only sites and small well sites.

EPA is also asking if there are technologies that may not easily work within the proposed matrix and how such technologies work, including empirical data that would allow for additional evaluation of parameters in the proposed matrix; how emissions reduction equivalency can be demonstrated for those technologies compared with the standard OGI work practice; and how the matrix would need to

[25] Supplemental, p. 130, 135.
[26] Id. p. 133.
[27] Id. p. 133-34.
[28] Id. p. 134.
[29] Id. p. 135.
[30] Id. p. 136.

be changed to support the use of such technologies. Finally, EPA asks stakeholders for input on ways to ensure they are "comfortable utilizing any approved alternative technologies and test methods."[31]

Table 2: Survey Matrix for Alternative Periodic Screening Approach for Affected Facilities Subject to Quarterly OGI Monitoring[32]

Minimum Screening Frequency	Minimum Detection Threshold of Screening Technology[33]
Quarterly + Annual OGI	≤1 kg/hr
Bimonthly (every two months)	≤2 kg/hr
Monthly	≤4 kg/hr
Bimonthly + Annual OGI	≤10 kg/hr
Monthly + Annual OGI	≤30 kg/hr

Table 3: Survey Matrix for Alternative Periodic Screening Approach for Single and Multi-Wellhead Only Sites and Small Well Sites[34]

Minimum Screening Frequency	Minimum Detection Threshold of Screening Technology[35]
Semiannual	≤1 kg/hr
Triannual	≤2 kg/hr
Triannual + Annual OGI	≤5 kg/hr
Quarterly + Annual OGI	≤15 kg/hr
Monthly + Annual OGI	≤30 kg/hr

If an owner or operator identified an emissions event using a periodic screening approach, the Supplemental proposes to require a ground based OGI survey to identify the source of the emissions and any other fugitive emissions occurring. EPA notes that any control device failure is a violation of the standards, and thus proposes "appropriate corrective action should be taken as soon as possible to address these failures."[36] Similarly, for covers and closed vent systems, EPA is proposing that appropriate corrective actions must ensure that the no detectable emissions level is continuously met.

Repairs would need to be completed within 30 days of the screening survey and, if the OGI survey confirms that the emissions were the result of a control device failure, EPA is proposing to require a root cause analysis to identify the corrective action within 24 hours of the ground-based survey. If the inspection results indicate a leak or defect in the cover or closed vent system, EPA proposes to require a root cause analysis to determine the cause within 5 days of completing the inspection.[37] EPA is seeking comment on the compliance timelines recognizing that "the length of time necessary to complete corrective actions will vary based on the specific action taken."[38]

---

[31] Id. p. 137.
[32] Id. p. 135-36. Well sites with major production and processing equipment, controlled storage vessels, natural gas-driven pneumatic controllers, associated covers and closed vent systems, and control devices, centralized production facilities, and compressor stations.
[33] Based on a probability of detection of 90 percent.
[34] Supplemental, p. 136.
[35] Based on a probability of detection of 90 percent.
[36] Supplemental, p. 138.
[37] EPA proposes additional reporting and recordkeeping requirements for operators that use the alternative matrix approach, proposed in Supplemental, Subpart OOOOb §60.542b.
[38] Id. p. 139.

Matrix for Alternative Continuous Monitoring Approach

To encourage owners and operators to adopt continuous monitoring technologies that can lead to greater emission detection, the Supplemental includes an alternative similar to EPA's refinery fenceline monitoring work practice standards. EPA notes that such technologies can have low detection sensitives, be cost effective by identifying the largest leaks in near real time, and enable companies to repair such leaks much more quickly compared to other detection technologies.

Under the proposed matrix approach, an owner or operator would conduct a root cause analysis whenever a methane emission rate exceeds a certain action level by mass (in kilograms per hour) at the boundary/fenceline of a facility to account for upwind contributions and meteorological effects. The matrix enables technologies that can quantify site-level methane emissions rate that have a detection level an order of magnitude less than the proposed action level and can produce a valid mass emissions rate at least once every twelve hours. Recognizing that technologies vary widely including how sources identify leaks, the Supplemental proposes two action levels: "(1) a long-term action level to limit emissions over time and (2) a short-term action level to identify large leaks and malfunctions."[39] Both action levels would apply to owners and operators electing to use this alternative. EPA used the FEAST Model to determine the long-term action level.

Table 4: Proposed Alternative Continuous Monitoring Approach for New and Existing Well Sites[40]

Type of Site	Type of Action Level	Proposed Monitoring and Repair Requirements
Wellhead-only sites	Long term	1.2 kg/hr, rolling 90-day average calculated each day
	Short term	15 kg/hr, rolling 7-day average calculated each day
Other well sites and compressor stations[41]	Long term	1.6 kg/hr, rolling 90-day average calculated each day
	Short term	21 kg/hr rolling 7-day average calculated each day

For each action level, EPA proposes that owners or operators initiate a root cause analysis within five calendar days of an exceedance of either the short-term or long-term action level and that the initial corrective action identified be completed within five calendar days of an identified exceedance of a short-term action level and within 30 calendar days of an exceedance of a long-term action level. And, if the corrective actions take longer than 30 days for any action level or the emissions readings remain above the action level, EPA proposes that the owners or operator would need to submit a corrective action plan within 60 calendar days of the initial exceedance.

EPA also notes that certain technologies (e.g., camera-based continuous systems) are "not suitable for the proposed alternative continuous monitoring approach because they are not capable of quantifying site-level methane emissions."[42] However, EPA asks whether there are different approaches that should be included for different types of continuous monitoring systems and how equivalency could be determined. EPA also seeks input on the action levels, response requirements, and the use of emissions intensity or production as a metric to develop the action levels.

[39] Id. p. 141.
[40] Id. p. 142; see also Supplemental, Subpart OOOOc §60.5398c.
[41] "For well sites with major production and processing equipment (including small well sites), centralized production facilities, and compressor stations". Supplemental, Subpart OOOOb §60.5398b(c)(4)(ii).
[42] Supplemental, p. 143.

Alternative Test Method Approval

For both the periodic screening and continuous monitoring approaches, EPA proposes a new process for entities to seek EPA approval of alternative test methods for alternative advanced technologies. This process is designed to enable greater use of such technologies compared to using the CAA's alternative means of emission limitation (AMEL) approval process.[43] Once EPA approves a test method for an alternative technology within 270 days, the agency proposes to post it to the Emission Measurement website.[44] Any owner or operator "who meets the specific applicability for the alternative method" may use this approach for compliance provided notifies EPA in its first annual report following implementation.[45]

EPA explains that the approval process is necessary "due to the lack of standard methods and performance specifications for these types of systems."[46] The Supplemental states that the alternative test method provisions in 40 C.F.R. § 60.8(b)(3) can serve as the basis for EPA's approval framework.[47] While EPA notes it typically uses this provision to approve compliance with a numerical emission standard and that work practice standards are different, the agency reasons that "there is precedent for approving alternative methods" so long as they can be demonstrated at the same or higher stringency.[48] EPA explains that it has clarified that certain provisions within work practices such as monitoring requirements are delegable.[49] However, EPA is soliciting comment "on the use of this provision at 40 CFR 60.8(b)(3) for the approval of the alternative test method for an alternative technology for measurements".[50]

To streamline the approval process, EPA proposes four pre-qualifications for entities seeking to approve their technology:

(1) Requestors must have representation in the US;
(2) If the requestor is not an owner/operator, then the requestor must "directly represent the underlying technology" and that technology "must have been applied to methane measurements or monitoring in the oil and gas sector either domestically or internationally;"
(3) The technology must be commercially available; and
(4) The requestor must be able to submit to EPA the information required to approve the technology.[51]

In addition, EPA proposes that requesting entities provide the following as part of the application:

(1) The applicability of the technology (i.e., site-specific, basin-specific, or broadly applicable across the sector);
(2) A description of the measurement systems;

---

[43] The CAA §111(h)(3) AMEL process does not have time limitations for EPA approval, is burdensome, does not explicitly allow broad sector-wide use of the technology after approval, and has never successfully approved a new technology to date. The Supplemental includes AMEL provisions in proposed NSPS §60.5399b, which retain the changes to AMEL from the [2020 Technical Rule](). Meanwhile, EPA proposes new alternative test method provisions in proposed Subpart OOOOb §60.5398b(d), under EPA's alternative performance test method provisions in 40 C.F.R. § 60.8(b)(3).
[44] The Supplemental indicates the website would be posted here: https://www.epa.gov/emc/oil-andgas-approved-alternative-test-methods.
[45] Supplemental, p. 148.
[46] Id. p. 147.
[47] "Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator . . . approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance." 40 C.F.R. § 60.8(b)(3).
[48] "The fenceline monitoring work practice in 40 CFR part 63 subpart CC allows owners and operators to seek an alternative test method for use of technologies other than the prescribed sorbent tube monitoring with Method 325 A and B of appendix A to 40 CFR part 63. See 40 CFR 63.658(k)(1)." Supplemental, p. 147.
[49] Id. FN 96 (citing 65 FR 55810 (Sept. 14, 2000)).
[50] Id. p. 147.
[51] Supplemental, Subpart OOOOb §60.5398b.

(3) Supporting information verifying that the technology meets the desired detection threshold(s) as applied in the field;
(4) A detailed description of the alternative testing procedure(s),[52] including data quality objectives to ensure the detection threshold(s) are maintained and procedures for a daily check of the measurement sensitivity under field conditions; and
(5) Standard operating procedures consistent with the EPA's guidance and including safety considerations, measurement limitations, personnel qualification/responsibilities, equipment and supplies, data and record management, and quality assurance/quality control.[53]

Once the information is submitted, EPA proposes to approve or disapprove of the technology within 270 days. However, if EPA does not make a determination within 270 days, the alternative test method would receive conditional approval, though EPA would retain its authority to rescind any previous approval if it were to dispute any of the alternative test method results.

Broadly, EPA is seeking feedback on its proposed approach to approve technologies and enable owners and operators to deploy them consistent with the matrices. For example, EPA asks whether it should consider requiring any additional or different information from entities submitting applications. EPA is also seeking feedback on the approval timeline.

Fugitive Emissions Monitoring Plans

To implement the alternative technology matrix approach, EPA proposes to modify the requirements for fugitive emissions monitoring plans. The Supplemental proposes to allow owners and operators to develop site-specific monitoring plans or a monitoring plan that covers multiple sites. The plan would need to include specific information including the sites that would be covered as well as the test method(s) used.

EPA also clarifies the timeframes for conducting the initial screening or monitoring. For periodic screening approaches, the Supplemental proposes that an initial screening survey be conducted within 90 days of the startup for any new or modified fugitive emissions components affected facility. For existing facilities, the initial screening must be within 90 days or, for any facilities that were previously complying with the fugitive emissions requirement with OGI, EPA proposes that a facility shifting to a periodic screening approach must conduct the initial screening no later than the date of the next required OGI survey. For continuous monitoring approaches, owners and operators of new and existing sources would have to install and begin conducting continuous monitoring within 120 days.

Super-Emitter Response Program

EPA states in the Supplemental that a relatively small number of large emissions events contribute as much as half of the methane emissions from oil and gas. These events, which EPA refers to as "super-emitters," can be caused by malfunctioning equipment or abnormal operating conditions. Along with their emissions impact, EPA states that these large emissions events have a "significant impact on the communities where they are located."[54] EPA explains that its proposed super-emitter response program would provide a "backstop" for the new standards in the rule, which would already reduce many unintentional releases, by identifying large and often intermittent releases that an inspection program may otherwise miss.[55] The program's objective is to provide a remedy for "large emission events that disproportionately contribute to methane emissions from the Crude Oil and

[52] The preferred format is described at https://www.epa.gov/sites/default/files/2020-08/documents/gd-045.pdf.
[53] Supplemental, p. 149.
[54] Id. p. 152.
[55] Id.

Natural Gas source category and can be accompanied by health-harming pollution that affects nearby communities."[56]

In the 2021 Proposal, EPA provided a conceptual outline for the super-emitter program and solicited comments, including about how information collected by communities and others would be used to address large emissions events. The Supplemental builds on the 2021 Proposal and comments EPA received and proposes to require a quick response to large emissions events when they are identified by regulators or certified third parties. EPA anticipates that the program would be beneficial for communities with environmental justice concerns who are disproportionally exposed to leaks, including through opportunities for communities to partner with organizations conducting remote sensing and more transparent information about neighboring facilities.

What is the super-emitter threshold?
EPA proposes to define a super-emitter event as "emissions of 100 kg/hr or greater of methane," which EPA describes as "a very high threshold that encompasses the largest emissions events."[57] EPA notes that emissions as such levels will not duplicate other actions required by the rule (e.g., leak detection and repairs) and are not expected to occur in "normal operations."[58] EPA expects the program will focus on leaks from individual well sites, centralized production facilities, compressor stations, and natural gas processing plants. EPA expects that it will be cost-effective to quickly address these emissions as they will represent events that "release more methane in a single week than the total methane cost-effectively prevented over the course of an entire year at sources covered by the fugitive emissions program."[59]

What detection technologies are allowed?
EPA explains that "some flexibility is appropriate in the type of technology that could be utilized for the detection of super-emitters, provided that the technology can be safely deployed and will reliably identify super-emitter emissions events."[60] Thus, EPA proposes to allow only the use of remote-sensing technologies including remote-sensing aircraft, mobile monitoring platforms, or satellites.

How are third parties approved to do super-emitter detection?
The Supplemental outlines the process for EPA to approve third parties as qualified third-party notifiers based on their expertise to detect and interpret or analyze data collected by the technology. EPA would maintain a public list of approved qualified third-party notifiers to enable owners and operators to verify any notification before acting on a super-emitter event. Qualified third parties may include technology vendors, industry, researchers, nonprofit organizations, or other parties demonstrating technical expertise.

What happens if a super-emitter event is detected?
EPA proposes that qualified third-party notifiers would be required to provide owners and operators of a super-emitter event with "credible, well-documented identification" of the event using an "allowable remote-sensing technology or approach."[61] The specific information required would include:

(1) Location of emissions;
(2) Description of the technology and sampling protocols used to identify the emissions;

[56] Id. p. 156.
[57] Id. p. 151.
[58] Id. p. 159.
[59] Id.
[60] Id. p. 160.
[61] Id. p 153.

(3) Documentation of the emissions (e.g., aerial imaging with emissions plume depicted);
(4) Quantified emissions rate;
(5) Data and times of detection and of analysis confirming super-emitter emissions event occurred; and
(6) Signed certification that the notified is an EPA-approved entity.[62]

At the same time as the notification to the owner or operators, the third-party notifiers would also provide a copy to EPA and any delegated state authority. EPA is proposing it will make such copies available to the public and the third-party notifier may also make such information available on other public websites. EPA notes that it will "generally not verify or authenticate the information in third party reports prior to posting."[63] However, EPA is asking stakeholders whether it should establish a procedure for owners and operators to ask EPA to "reconsider the approval granted to a third-party notifier."[64] For example, the Supplemental suggests EPA could consider removing a third party from the pre-approved list if more than three notifications were made in error for the same owners or operator.

Once notified of a documented super-emitter, EPA proposes that the owner and operator would be required to take several steps. First, the owner or operator would initiate root cause analysis within 5 days and take initial corrective action, if needed, within 10 days. This root cause analysis and corrective action "could range from a survey using OGI or other technologies combined with repairs of any leaks identified, to visual inspections of thief hatches and closing any found open or unlatched."[65] The owner or operator would then submit: (1) a corrective action plan to EPA within 30 days and (2) a written report addressing the root cause and corrective action to EPA and state or tribal authority within 15 days of completion. EPA notes in the proposal that it intends to post all reports online. Additionally, the Supplemental includes a process for owners and operators to rebut a notification.

What is the legal basis for the program?
EPA includes two legal frameworks as the statutory basis for the proposed program. First, EPA proposes that these large emissions sources are each an "affected facility/designated facility," with the super-emitter response program as BSER standard for those facilities.[66] EPA proposes a new super-emitter affected facility under NSPS OOOOb and designated facility under EG OOOOc, which is defined as "equipment or control devices, or parts thereof, at a well site, centralized production facility, compressor station, or natural gas processing plant, that causes a super-emitter emissions event (i.e., any emissions detected using remote detection methods with a quantified emission rate of 100 kg/hr of methane or greater)."[67]

Alternatively, EPA reasons that the super-emitter response program could be justified as "part of the standards and requirements that apply to individual affected/designated facilities under this rule," providing an additional compliance assurance measure and an additional work practice standard.[68] However, EPA notes that "despite the proposed incorporation, the super-emitter response program is nevertheless severable from the standards of performance and work practice standards that are being separately established for each of the sources addressed in this rule."[69]

[62] Id. p. 162.
[63] Id. p. 163.
[64] Id.
[65] Id. p. 166.
[66] Id. p. 168.
[67] Id.
[68] Id. p. 173.
[69] Id. p. 174.

EPA also notes that it retains oversight over "all key decision-making elements of the program," and therefore, "a greater role for the Agency in reviewing third-party notifications would be an unnecessary task and duplicative of the predicate approval processes and subsequent revocation procedure."[70] However, EPA is seeking feedback on EPA's role of reviewing and/or approving third-party notifications before owners and operators have an obligation to respond, and how to ensure any increased role does not "meaningfully" delay the mitigation of large emission events.[71]

Other Equipment-Specific Requirements

The Supplemental includes several equipment requirements and emission standards that are more stringent than included in the 2021 Proposal. EPA also includes some flexible compliance pathways. While our Appendix lists each element of the rule, here we highlight a few that are critical to the rule delivering the projected emission reductions.

EPA proposes to require zero emissions standard for all pneumatic pump affected facilities[72] with a tiered flexibility structure for sites based on site-specific conditions. EPA explains that this is a "significant change from the November 2021 Proposal, which would have required that emissions from pneumatic pump affected facilities be routed to control or to a process, but only if an existing control or process was on site."[73] In the Supplemental, EPA proposes that pumps can only be driven by natural gas when the affected facility does not have access to electrical power and an engineer certifies that it is "not technically feasible" to use a solar powered pneumatic pump or a generator.[74] If an affected facility powers the pneumatic pump with natural gas, it must route emissions to a process through a closed vent system unless it is "not technically feasible."[75] If routing is infeasible, then the resulting requirements vary depending on the number of pumps at the site.[76]

To reduce the use of flares for eliminating venting of associated gas from oil wells, EPA proposes four possible compliance pathways: recovering the associated gas from the separator and (1) routing the gas to a sales line, (2) using the recovered gas as an onsite fuel source, (3) using recovered gas for another useful purpose, or (4) reinjecting it into a well for enhanced oil recovery. The Supplemental proposes to allow gas to be routed to a flare only if these four options are infeasible. Flaring or other combustion devices would need to achieve 95 percent reduction in methane and VOC emissions, and flaring would be subject to more comprehensive monitoring requirements.

The Supplemental also includes standards for dry seal centrifugal compressors and intermittent bleed pneumatic controllers for the first time. EPA proposes more rigorous standards for wet seal centrifugal compressors as well.

---

[70] Id. p. 165.
[71] Id.
[72] "[T]he pneumatic pump affected facility definition changed from being a single pump in the November 2021 proposal to the collection of pumps at a site in this supplemental proposal." Id. p. 231.
[73] Id. p. 230.
[74] Supplemental, Subpart OOOOb §60.5393b(a)-(c).
[75] To demonstrate it is technically infeasible, an owner or operator must have a certified demonstration that "must include . . . safety considerations, distance from a process, pressure losses and differentials which impact the ability of the process to handle all of the pneumatic pump affected facility emissions routed to it, or other technical reasons the process cannot handle all of the pneumatic pump affected facility emissions routed to it." Id. §60.5393b(d)-(e).
[76] "If there are four or more natural gas-driven pumps at the site, the proposed rule would require that the emissions from all pumps at the site be collected and be routed to a control device that achieves 95 percent reduction of methane and VOC. If there are less than four natural gas-driven diaphragm pumps at the site without access to electricity, the proposed requirements for pumps at the site would be the same as in the November 2021 Proposal, i.e., route to an existing control device that achieves 95 percent emissions reductions." Supplemental, p. 231.

In short, EPA seeks feedback on the proposed compliance requirements, including input on the timelines, possible additional compliance options, and how owners and operators anticipate making changes at their sites.

Considerations for States' Compliance Plans for Existing Sources

Once EPA establishes an NSPS for a particular source category, EPA must issue EGs for existing sources and establish the process for states to submit plans that establish, implement, and enforce standards of performance for existing sources. The Supplemental includes compliance deadlines for states submitting plans and for existing sources complying with such plans as well how EPA interprets states' authority to include compliance flexibilities, such as states' authority to consider, "among other factors, remaining useful lives of the existing source."[77]

However, EPA also notes that additional deadlines will be included in a forthcoming rulemaking, including the date by which EPA must approve state plans, which is a key factor for the IRA Methane Fee exemption.

Proposed Deadlines for State Compliance Plans

For existing sources under OOOOc, EPA proposes deadlines for states to submit compliance plans, and for sources to comply with requirements, to reflect the time required for retrofit considerations and potential supply chain issues.[78]

Recognizing that states usually have three years to develop state implementation plans under section 110 of the CAA, EPA proposes a shorter time frame of 18 months after the final publication of the EGs for states to submit their section 111 plans. [79] EPA states that the short deadlines are consistent with the requirement of CAA Section 111(d) that EPA promulgate procedures "similar" to CAA Section 110 and the D.C. Circuit's directive to "engagement meaningfully with the different scale" of the section 111(d) and 110 plans, while also considering impacts to public health and welfare.[80]

EPA further proposes that states comply with the standards of performance no later than 36 months following the state plan submittal deadline. EPA had proposed a two-year compliance deadline in the 2021 Proposal, but lists several factors that supported this longer timeframe, including the number of designated facilities, the complexity of the requirements, and the availability of equipment. EPA also states that it "chose to include a uniform compliance timeline for all designated facilities."[81]

However, given these longer compliance deadlines, EPA also proposes that states must include legally enforceable increments of progress if states allow compliance schedules that extend beyond three years after the state submittal deadline. EPA proposes that those state plans require companies to include: (1) a final compliance control plan that can cover "all of the company's designated facilities in the state in lieu of submitting a plan for each designated facility" within 2 years of state plan submission; and (2) a final compliance report that can cover "all of the company's

[77] 42 U.S.C.A. § 7411(d)(2)(B).
[78] As EPA acknowledged in its 2021 Proposal, the D.C. Circuit vacated the deadlines by which states must submit compliance plans and EPA must act on those state plans.[78] EPA is drafting rules to govern these timing actions but currently no regulations are in place for EGs promulgated after July 8, 2019.These rules are currently under review at OMB, https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202204&RIN=2060-AV48.
[79] See 40 CFR § 60.23 & 42 U.S.C.A. § 7410(a)(1).
[80] Supplemental, p. 448.
[81] Id. p. 461.

designated facilities in the state in lieu of submitting a plan for each designated facility" within 60 days of the state plan compliance date.[82]

In terms of the timing for EPA to approve or disapprove any submitted states plans or timing for any federal plan, EPA notes that its forthcoming rulemaking will include such deadlines.

Flexibilities in State Compliance Plans

EPA's Supplemental includes presumptive standards that states can use as a "model rule" and 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."[83] However, as states develop their plans, many are likely to want to consider compliance flexibility options including ways to reflect any existing state programs.

More Stringent Standards

EPA proposes to allow states to include requirements that are more stringent than the EG. EPA notes other factors that "states may wish to account for in applying a more stringent standard than required under an EG include, but are not limited to, early retirements, effects on local communities, and availability of control technologies that allow a source to achieve greater emission reductions."[84] EPA will evaluate these state plans on a case-by-case basis by requiring states to adequately demonstrate that the state standards are more stringent than the presumptive standards.

Trading and Averaging

With respect to states' authority to provide compliance flexibility, EPA explains that it interprets section 111 of the CAA to authorize states to establish standards of performance that "in the aggregate, would be equivalent to the presumptive standards."[85] Thus, EPA proposes to enable states to allow trading and averaging.

To compare state plans against the stringency of EG OOOOc, EPA outlines the two approaches it considered: (1) total program evaluation, and (2) source-by-source evaluation. The first—total program evaluation—EPA defines as one that would enable some sources to get more reductions than the presumptive standard in the EG and others reduce less, with the overall reductions equal or greater than what would be achieved in the aggregate across all designated facilities if the presumptive standards were implemented. For this rule, however, EPA proposes to reject this approach based on "challenges and complexities that are unique to the Crude Oil and Natural Gas source category."[86]

The second approach—source-by-source evaluation—would consider equivalency for one or more designated facilities compared to their respective presumptive standards. For this approach, EPA proposes three steps to determine if a state can use source-by-source evaluation as part of their state plans. First, determine if the state's designated facility definition, pollutant, and format are the same as the presumptive standard. Second, demonstrate that the emission reductions that will be achieved by the designated facilities will be equal or greater than what would be achieved under the presumptive standards. And third, demonstrate that the compliance measures (e.g., monitoring, recordkeeping, and reporting) are at least as effective as the presumptive standard.

[82] Id. pp. 464-66.
[83] Id. p. 25.
[84] Id. p. 427.
[85] Id. p. 379.
[86] Id. pp. 380-81.

Remaining Useful Life and Other Factors
EPA also discusses states' discretion to consider remaining useful life and other factors ("RULOF"). Although EPA notes it retains the authority to determine if that state plan is "satisfactory". EPA proposes an analytical framework to consider if less stringent standards are warranted if a facility demonstrates installing the control technology requires costs that are unreasonable, is physically impossible, or involves consideration of factors that are "fundamentally different" than the factors that EPA considered in setting BSER.[87] EPA proposes to require that "when an operational condition is used as the basis for applying a less stringent standard, the state plan must include that condition as a federally enforceable requirement."[88]

EPA solicits comment on whether "EG OOOOc should include a single 'outermost retirement date' that would define the maximum length of time that would qualify for a designated facility to operate at a less stringent standard based on remaining useful life."[89] Additionally, EPA proposes to require states seeking to invoke RULOF to identify how a less stringent standard could result in disparate health and environmental impacts to communities most affected by and vulnerable to designated facilities.

Inflation Reduction Act
Although not the focus on the Supplemental, EPA "acknowledges the potential interplay" between the IRA methane provisions and methane regulations.[90]

The IRA assesses a charge for methane emissions "waste" from certain segments of oil and gas operations that report more than 25,000 metric tons per year of CO_2 equivalent under the Greenhouse Gas Reporting Program (GHGRP) Subpart W starting in 2025.[91] The IRA exempts affected facilities from the fee program if they are in compliance with requirements under CAA sections 111(b) and (c) if EPA determines that those regulations "will result in equivalent or greater emissions reductions as would be achieved" by the 2021 Proposal[92] and standards and plans under 111(b) and (d) are "approved and in effect in all states with respect to the applicable facilities" or if a facility's methane emissions do not exceed "0.20 percent of the natural gas sent to sale from the facility."[93] The new law also directs EPA to revise Subpart W to ensure its reporting and calculations are based on "empirical data" by August 2024, which will impact whether facilities meet the threshold emissions to be covered by the fee.

Thus, while it is expected that facilities will pay a fee in the initial gap years given the timing to finalize this rule and for EPA to approve state plans, EPA is seeking comment on approaches for establishing this IRA equivalence determination, including temporal and geographical considerations and the emissions economic impacts of these programs. EPA also seeks input on whether it should compare submitted or approved state plans and how a state's reliance on RULOF might affect the determination. Separately, the agency issued a request for information on the implementation of the methane fee.[94]

---

[87] Id. p. 393.
[88] Id. p. 415.
[89] Id.
[90] Id. pp. 64-68.
[91] 42 U.S.C.A. § 7436.
[92] Supplemental, p. 64.
[93] Inflation Reduction Act § 60113(f).
[94] EPA, Methane Emissions Reduction Program, https://www.regulations.gov/docket/EPA-HQ-OAR-2022-0875/document.

Next Steps for EPA and Other Federal Agencies

The Supplemental is another step by EPA to establish a durable regulatory framework that achieves significant methane emission reductions from oil and gas sources. Stakeholder comments offering constructive feedback and solutions will be essential to support EPA's effort to finalize a workable, effective rule in 2022 that is based on a sound technical and legal record. Once EPA finalizes the rule, this action will trigger additional steps for states, oil and natural gas companies, and technology developers to consider how entities can cost-effectively comply with the requirements to achieve significant emission reductions. EPA's final rule, combined with separate regulatory actions to implement the IRA's methane provisions, presents an opportunity to design regulations that can reflect the fast pace of technology advancements and thereby increase the scale of emission reductions throughout the oil and natural gas infrastructure. You can stay updated on EPA's methane regulation on our Regulatory Tracker and Trackers newsletter, our Methane Rules for Oil and Gas Facilities page, and by signing up for our EELP newsletter.

Appendix: Comparison of 2016 Requirements, 2021 Proposal, Supplemental

<table>
<tr><th>Source</th><th>2016 Rule[95]</th><th>2021 Proposal</th><th>Supplemental</th></tr>
<tr><td>Well sites emitting fewer than 3 tpy of methane*</td><td>Monitor semiannually using OGI or Method 21 monitoring.

Repairs within 30 days, resurvey within 30 days of the repair.</td><td>For new and existing sites, monitor by conducting a survey showing calculation of baseline.
For new and existing sites, first attempt at repair within 30 days, final repair within 30 days of first attempt.</td><td rowspan="2">*Single well head only sites and small well sites*
For new and existing sites, quarterly AVO inspections, repair identified leaks within 15 days.
Monitoring must continue until the well site has been closed including plugging the wells at the site and submitting a well closure report.

Multi-wellhead only sites with two or more wellheads:
For new and existing sites, quarterly AVO inspections, repair identified leaks within 15 days.
Semiannual OGI monitoring (or optional semiannual monitoring using EPA method 21 with 500 ppm defined as a leak).
First attempt at repair within 30 days of finding a leak; final repair within 30 days of the first attempt.
Monitoring must continue until the well site has been closed including plugging the wells at the site and submitting a well closure report.

Sites with major production and processing equipment and centralized production facilities:
For new and existing sites, AVO monitoring every other month; repair for indications of potential leaks within 15 days of inspection AND
For well sites with specified production and processing equipment: Quarterly OGI monitoring (optional quarterly</td></tr>
<tr><td>Well sites emitting at least 3 tpy of methane*</td><td>Monitor semiannually using OGI or Method 21 monitoring.

Repairs within 30 days, resurvey within 30 days of the repair.</td><td>For new and existing sites, monitor quarterly using OGI or Method 21 monitoring.
Potential to use alternative monitoring bimonthly.
For new and existing sites, a co-proposal would require those emitting between 3 and 8 tpy to submit to only semi-annual monitoring. Potential to use alternative monitoring bimonthly.
For new and existing sites, first attempt at repair within 30 days, final repair within 30 days of first attempt.</td></tr>
</table>

[95] Only applied to new and modified sources.

Source	2016 Rule[95]	2021 Proposal	Supplemental
			EPA Method 21 monitoring with 500 ppm define as a leak) First attempt at repair within 30 days of finding a leak; final repair within 30 days of the first attempt. Monitoring must continue until the well site has been closed including plugging the wells at the site and submitting a well closure report
Compressor stations*	Monitor quarterly using OGI or Method 21 monitoring. Repairs within 30 days, resurvey within 30 days of the repair.	For new and existing stations, monitor quarterly using OGI or Method 21 monitoring. Potential to use alternative monitoring bimonthly. New and existing compressor stations, attempt repair within 30 days, final repair within 30 days of first attempt.	Monthly AVO monitoring AND Quarterly OGI monitoring (option to use quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding a leak; final repair within 30 days of the first attempt.
Exception for well sites and compressor stations in Alaska North Slope*	Monitor quarterly using OGI or Method 21 monitoring. Repairs within 30 days, resurvey within 30 days of the repair.	For new and existing well sites and compressor stations, annual monitoring using OGI or Method 21 monitoring. Potential to use alternative monitoring bimonthly. New and existing well sites and compressor stations, attempt repair within 30 days, final repair within 30 days of first attempt.	For well sites and compressor stations on the Alaska North Slope, annual monitoring using OGI (Optional annual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding a leak; final repair within 30 days of the first attempt.
Storage Vessels	95% VOC emissions reduction from storage vessels for a tank with the potential to emit at least 6 tpy VOCs.	For new storage vessels, 95% VOC and methane emissions reduction from a single storage tank or tank battery with the potential to emit at least 6 tpy VOCs. For existing storage vessels, 95% reduction from a tank battery with potential to emit 20 tpy methane.	For new storage vessels, 95% VOC and methane emissions reduction from a single storage tank or tank battery with the potential to emit at least 6 tpy VOCs. For existing storage vessels, 95% reduction from a tank battery with potential to emit 20 tpy methane.

Source	2016 Rule[95]	2021 Proposal	Supplemental
Pneumatic controllers	For pneumatic controllers at onshore natural gas processing plants, zero bleed required. Does not include intermittent vent pneumatic controllers. Pneumatic controllers anywhere else, bleed no more than 6 standard cubic feet per hour (scfh). Does not include intermittent vent pneumatic controllers.	For new and existing sources, no bleed devices required at all sources. Includes intermittent vent pneumatic controllers.	For new and existing sources, use of zero-emissions controllers
Exception for pneumatic controllers in Alaska	Pneumatic controllers at onshore natural gas processing plants, zero bleed required. Does not include intermittent vent pneumatic controllers. Pneumatic controllers anywhere else, bleed no more than 6 scfh. Does not include intermittent vent pneumatic controllers.	Where power is not available, low bleed (< 6scfh) or, if functional needs require, high bleed devices (> 6scfh) may be used. Must inspect intermittent vents controllers to ensure they are not venting when idle.	For intermittent natural gas-driven pumps, OGI monitoring and repair of emissions from controller malfunctions. For continuous bleed natural-gas driven pumps, natural gas bleed rate no greater than 6 scfh.
Well Liquids Unloading	No NSPS regulating this source.	Unload with zero or minimal methane and VOC emissions. In both co-proposals, affected facilities must use best management practices to minimize venting, keep records of when venting occurs, and record incidents where best management practices are not followed.	Perform liquids unloading with zero methane or VOC emissions. If this is not feasible for safety or technical reasons, employ best management practices to minimize venting of emissions to the maximum extent possible.
Centrifugal compressors	Wet seal: 95% reduction in VOCs and GHG emissions. Excludes all wet seal centrifugal compressors that are located at well sites.	Wet seal: For new and existing compressors, reduce emissions by 95%. Includes wet seal centrifugal compressors that are located at well sites at centralized production facilities.	Wet seal: capture and route emissions from the wet seal fluid degassing system to a control device; 95% reduction of methane and VOC emissions. Dry seal: Conduct preventative maintenance and repair to maintain flow rate at or below 3 scfm.
Reciprocating compressors	Reduce emissions by replacing rod packing within 26,000 hours or 36 months of operation or	For new and existing compressors, replace the rod packing when leak rate is greater than 2 standard cubic	For new and existing compressors, repair or replace the reciprocating compressor rod packing in order to

Source	2016 Rule[95]	2021 Proposal	Supplemental
	collect emissions from the rod packing and route the rod packing emissions through a closed vent system under negative pressure.	feet per minute or collect and route emissions from the rod packing through a closed vent system under negative pressure.	maintain a flow rate at or below 2 scfm.
Pneumatic Pumps	Zero emissions required for diaphragm pumps at natural gas processing plants. 95% control of diaphragm pumps at well sites if there is an existing control or process onsite, but not required if the existing control achieves less than 95% reduction or if control is technically infeasible.	Zero emissions required for diaphragm and piston pumps at natural gas processing plants. 95% control of diaphragm and piston pumps in production segment if there is an existing control process onsite; 95% control of diaphragm pumps in transmission and storage segments if there is an existing control process onsite. 95% control not required if the existing control achieves less than 95% reduction or if control is technically infeasible. For existing sources, the same standards apply; excludes piston pumps in locations other than those at natural gas processing plants.	Use of zero-emission pumps that are not powered by natural gas. Methane and VOC emission rate of zero.
Well Completions	Subcategory 1 (non-wildcat and non-delineation wells): REC and a completion combustion device, except that venting may be used where combustion would be unsafe. Subcategory 2 (exploratory and delineation wells and low-pressure wells): Either use a completion combustion device or route flow back to completion vessels and use a separator. Combustion is not required where it would be unsafe.	Subcategory 1 (non-wildcat and non-delineation wells): REC and a completion combustion device, except that venting may be used where combustion would be unsafe. Subcategory 2 (exploratory and delineation wells and low-pressure wells): Either use a completion combustion device or route flow back to completion vessels and use a separator. Combustion is not required where it would be unsafe.	Subcategory 1 (non-wildcat and non-delineation wells): Combination of REC and the use of a completion combustion device, venting in lieu of combustion where combustion would present demonstrable safety hazards. Subcategory 2 (exploratory and delineation wells and low-pressure wells): Use of a completion combustion device.

Source	2016 Rule[95]	2021 Proposal	Supplemental
Equipment Leaks at Natural Gas Processing Plants	Method 21 LDAR or OGI as an alternative monitoring method with frequency of monitoring based on annual leakage.	For new and existing natural gas processing plants, OGI LDAR program or Method 21 LDAR program with frequency of monitoring delineated in Appendix K based on baseline methane emissions.	LDAR with bimonthly OGI following procedures in Appendix K.
Oil Wells with Associated Gas	No NSPS regulating this source.	For new and existing wells, route gas to a sales line. Where a sales line is not available, use gas onsite or flare in a way that achieves a 95% emissions reduction. Venting is not allowed.	For new and existing wells, route associated gas to a sales line. If access to a sales line is not available, the gas can be used as an onsite fuel source or used for another useful purpose that a purchased fuel or raw material would serve. If demonstrated that a sales line and beneficial uses are not technically feasible, the gas can be routed to a flare or other control device that achieves at least 95 percent reduction in methane and VOC emissions
Sweetening Units	Units with sulfur production rate of at least 5 long tons a day must reduce SO_2 by 99.9%. Units below this threshold must maintain records.	Units with sulfur production rate of at least 5 long tons a day must reduce SO_2 by 99.9%. Units below this threshold must maintain records. No standards proposed for existing sources.	Achieve required minimum SO_2 emission reduction efficiency

*For new and existing well sites and compressor stations, owners/operators have the option to use alternative monitoring system or alternative continuous monitoring system.