United States Government Accountability Office

Report to Congressional Requesters

April 2022

# OIL AND GAS

# Federal Actions Needed to Address Methane Emissions from Oil and Gas Development

GAO-22-104759

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## Federal Actions Needed to Address Methane Emissions from Oil and Gas Development

GAO Highlights

Highlights of GAO-22-104759, a report to congressional requesters

## Why GAO Did This Study

Methane is emitted into the atmosphere during oil and gas production—either through intentional releases or leaks. These emissions also result in the loss of marketable natural gas. BLM oversees oil and gas operations on federal lands, and EPA regulates emissions from these operations.

GAO was asked to review methane emissions from oil and gas development on federal lands. This report (1) describes the steps federal agencies have taken to reduce methane emissions from oil and gas, and implementation challenges; (2) examines actions selected industry entities are taking to reduce methane emissions; and (3) examines how selected states regulate methane emissions and to what extent those efforts could inform federal actions.

GAO reviewed federal regulations and interviewed agency officials, industry representatives, and stakeholders, including environmental groups and academics. GAO analyzed documentation on industry efforts and reviewed academic studies, analyzed seven selected states' current and proposed methane regulations and interviewed officials from these states.

## What GAO Recommends

GAO is recommending that (1) EPA provide greater flexibility for operators to use alternative technologies to detect methane emissions; and (2) BLM consider whether to require gas capture plans similar to what states require, including gas capture targets, on federal lands. EPA and Interior concurred with GAO's recommendations.

View GAO-22-104759. For more information, contact Frank Rusco at (202) 512-3841 or ruscof@gao.gov.

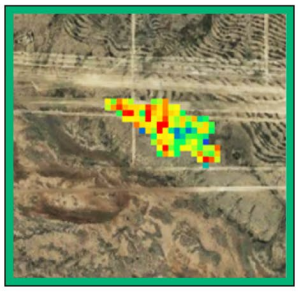
## What GAO Found

The Environmental Protection Agency (EPA) and the Department of the Interior's Bureau of Land Management (BLM) each issued regulations to reduce emissions of methane—a potent greenhouse gas—from oil and gas development. However, EPA and BLM encountered administrative and legal challenges in implementing them. For example, in 2016, EPA established national standards for methane emissions, but EPA repealed and curtailed those requirements in 2020. A June 2021 congressional resolution resulted in the reinstatement of the 2016 methane standards. EPA and BLM are in the process of developing proposed rulemakings to reduce methane emissions.

Several industry entities are voluntarily taking actions to reduce methane emissions, such as using aircraft and satellites to detect emissions (see fig.), in addition to the handheld devices required by EPA. However, few operators have applied to EPA for approval to use alternative technologies, which must achieve at least the same reduction in emissions as EPA's required technology. Representatives from some industry entities and stakeholders said they experienced challenges in meeting EPA's requirements, including that site-specific applications are time- and resource-intensive. Without greater flexibility in the process for approving alternative technologies, EPA may hinder the adoption of innovative approaches for detecting and reducing methane emissions.

**Technologies Used to Detect Methane Emissions from Oil and Gas Development Include Piloted Aircraft, Satellites, and Ground-Based Sensors**

A piloted aircraft with a sensor



An image captured from a satellite

A fixed, continuous monitoring device

Sources: Scientific Aviation, Inc. (left); © 2021 GHGSat Inc. (center); GAO (right). | GAO-22-104759

Selected states have regulations to reduce methane emissions from oil and gas development that exceed BLM's requirements. Historically, gas could be emitted into the atmosphere if the operator did not have the ability to capture it, but three states require operators to submit plans for capturing gas when applying for a drilling permit. Two of these states have enforceable targets for capturing gas. BLM does not require operators on federal lands to submit plans, due to legal challenges. In September 2021, BLM officials said that the agency is considering requiring waste minimization plans from operators but does not expect to include gas capture targets in the proposed rule. Without taking steps to require gas capture during production, BLM is potentially forgoing revenue from wasted gas, which contributes to pollution and greenhouse gas emissions.

# Contents

## Abbreviations

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|---|---|
| AMEL | alternative means of emission limitation |
| BLM | Bureau of Land Management |
| EPA | Environmental Protection Agency |
| LDAR | leak detection and repair |
| NSPS | new source performance standards |
| NTL-4A | Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases |
| OGI | optical gas imaging |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| PIPES Act | Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020 |
| VOCs | volatile organic compounds |

U.S. GOVERNMENT ACCOUNTABILITY OFFICE
441 G St. N.W.
Washington, DC 20548

April 20, 2022

The Honorable Joe Manchin III
Chairman
Committee on Energy and Natural Resources
United States Senate

The Honorable Thomas R. Carper
Chairman
Committee on Environment and Public Works
United States Senate

The Honorable Maria Cantwell
United States Senate

The Honorable Angus S. King, Jr.
United States Senate

According to the Environmental Protection Agency (EPA), concentrations of greenhouse gases have increased over the last few hundred years due to human activities, and burning fossil fuels changes the climate more than any other human activity. Methane is a greenhouse gas with a global warming potential 28 to 34 times higher than carbon dioxide over a 100-year period.[1] It is also a precursor to the formation of ground-level ozone, a harmful air pollutant.[2] Experts estimate that about 60 percent of total global methane emissions come from human activities, of which fossil fuel production, including natural gas, accounts for about 34 percent.[3]

[1]F. J. Cardoso-Saldaña and D. T. Allen, "Projecting the Temporal Evolution of Methane Emissions from Oil and Gas Production Sites," *Environmental Science & Technology*, vol. 54, no. 22 (Oct. 27, 2020): 14172-14181. https://doi.org/10.1021/acs.est.0c03049.

[2]Congressional Research Service, *Methane and Other Air Pollution Issues in Natural Gas Systems* (Washington, D.C.: Sept. 17, 2020). According to EPA, ozone at ground level is a harmful air pollutant because of its effects on people and the environment, and it is the main ingredient in smog. While the principal component of natural gas is methane, natural gas may contain smaller amounts of other hydrocarbons, such as ethane, propane, and butane, as well as heavier hydrocarbons. These nonmethane hydrocarbons include types of volatile organic compounds, classified as ground-level ozone precursors (smog), as well as, in some cases, hazardous air pollutants.

[3]National Academies of Sciences, Engineering, and Medicine, *Improving Characterization of Anthropogenic Methane Emissions in the United States* (Washington, D.C.: The National Academies Press, 2018). https://doi.org/10.17226/24987.

According to the Department of the Interior, operators produced about 3.3 trillion cubic feet of natural gas on federal leases in fiscal year 2020, of which 80 percent is methane.[4] While most of the gas produced on leased federal lands is captured and sold, some is emitted during production, such as from leaks or intentional releases as part of ongoing operational or safety procedures.[5] Leaks, or "fugitive" emissions, may occur at any stage of the production process. Operators intentionally release gas directly into the atmosphere (venting) or burn the gas (flaring), which results in the loss of gas.[6]

Different federal agencies manage emissions from oil and gas development. Interior's Bureau of Land Management (BLM) is responsible for oversight of oil and gas operations and production from onshore federal leases and certain Indian leases. The production of oil and natural gas from leases on federal lands is a significant source of revenue for the federal government. According to BLM, federal onshore oil and gas leases generate about $3 billion annually in federal revenues, including from royalties—which operators pay the federal government once production of oil or gas in paying quantities starts on a lease.[7] EPA, through the Clean Air Act, regulates certain air emissions from oil and gas development. In addition, EPA may delegate regulatory authority to states to implement and enforce applicable regulations through a state's environmental department and public utility commission or similar agency. However, states may adopt their own regulations that exceed federal

[4]For the purposes of this report, we refer to owners and operators of oil and gas companies subject to EPA and Bureau of Land Management regulations as "operators."

[5]Natural gas will vary in content but, on average, is approximately 80 percent methane, with the remaining 20 percent a mix of other hydrocarbons and nonhydrocarbons, such as carbon dioxide and nitrogen.

[6]According to the Department of Energy, flaring is the process of combusting natural gas and oxygen at the wellhead using a dedicated flame, which converts methane and other combustible gases to carbon dioxide, water, and heat. Combustible gases are flared most often due to emergency relief, overpressure, process upsets, startups, shutdowns, and for other operational safety reasons. Venting refers to the direct release of natural gas. Flaring is less harmful from a greenhouse gas perspective because the methane that is vented is a more potent greenhouse gas than the carbon dioxide that results from flaring. Venting and flaring represent both the loss of a valuable natural resource and a source of environmental impact.

[7]Operators pay the federal government royalties of at least 12.5 percent of the net value of production removed or sold from the lease minus allowable deductions for the transportation costs of oil or gas, or processing costs for gas.

requirements. A number of states have specifically targeted methane as part of their regulations.

We previously reported in 2010 and 2016 on the extent to which the federal government measures emissions and accounts for gas lost to venting and flaring. In 2010, we found that available estimates of vented and flared natural gas vary but that volumes were likely underestimated (for more information on approaches to measuring methane and methane emission estimates, see app. II).[8] We also found that approximately 40 percent of estimated vented and flared natural gas on onshore federal leases could be economically captured with available technologies, potentially reducing greenhouse gas emissions. In 2016, we reported on Interior's guidance for accounting for natural gas emissions from oil and gas development on federal lands, resulting in four recommendations, including providing additional guidance in how operators are to report emissions.[9]

You asked us to review methane emissions from oil and gas development on federal lands. This report (1) describes the steps that federal agencies have taken to reduce methane emissions from oil and gas development, and the implementation challenges that agencies have faced; (2) examines actions that selected industry entities are taking to reduce methane emissions from oil and gas development and the extent to which federal regulations affect industry response; and (3) examines how selected states regulate methane emissions from oil and gas development and the extent to which those efforts could inform federal actions.

To address our objectives, we reviewed prior federal regulations and interviewed federal officials from Interior and EPA on technology requirements for leak detection and repair and prior and proposed

[8]GAO, *Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared Natural Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases*, GAO-11-34 (Washington, D.C.: Oct. 29, 2010).

[9]GAO, *Oil and Gas: Interior Could Do More to Account for and Manage Natural Gas Emissions*, GAO-16-607 (Washington, D.C.: July 7, 2016). Interior generally concurred with the four recommendations, two of which are closed as implemented, and two of which are open.

rulemakings.[10] We analyzed documentation on industry efforts and interviewed representatives from a nongeneralizable sample of 11 industry entities (oil and gas operators, industry groups, and technology companies) and five stakeholders (academics, environmental groups, and national coalitions).[11] We identified stakeholders based in part on a literature review and selected our nongeneralizable sample to obtain a range of methane reduction technologies.[12] In addition, we interviewed state officials and analyzed current and proposed state regulations to determine their potential to inform the federal response. We identified states, in part, by independently researching which states directly regulated methane or indirectly regulated methane by regulating volatile organic compounds (VOCs). We also reviewed total oil and gas production by state for 2019 (the latest available at the time of selection) from the Energy Information Administration to confirm that the states we identified have high oil and gas production. From the list of high oil- and gas-producing states we identified, we selected seven states because they proposed or issued final regulations on methane or VOCs or experienced a large amount of flaring. Findings from our selected interviews, including those with industry entities, stakeholders, and state officials, cannot be generalized to those we did not select and speak with. A more detailed discussion of our scope and methodology is presented in appendix I.

We conducted this performance audit from January 2021 to April 2022 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain

[10]The Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) regulates pipeline safety, including releases from certain oil and gas pipelines. Given that the focus of this review is on upstream oil and gas activities rather than transportation facilities, we did not include PHMSA in the scope of this review. PHMSA officials report that, in response to the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act (PIPES Act) of 2020, PHMSA is developing regulations to reduce emissions but that PHMSA does not currently have any express methane emissions regulations in effect. PHMSA officials also stated that other rulemaking efforts could affect methane emissions by reducing the frequency or severity of gas pipeline incidents.

[11]Of the 13 industry entities we selected, we were unable to contact two to interview. We therefore interviewed 11 of the remaining selected industry entities. Of the six stakeholders we selected, one indicated that it did not have recent work on methane emissions and declined to be interviewed. We therefore interviewed five of the remaining selected stakeholders.

[12]We analyzed operators' annual reports and reports from EPA- or industry-led initiatives. We also analyzed documentation from stakeholders, including academic studies identified in a literature search. For more information on our literature search, please see app. I.

sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

# Background

## The Oil and Gas Production Process and Release of Methane and Other Emissions

The oil and gas production process involves several stages, including drilling; well completion (the process of making a well capable of production); and initial production of the resource, along with routine operation and maintenance activities at the development site. Throughout these stages, operators typically vent or flare natural gas, including methane. Methane can also escape from leaks and devices that are powered by natural gas (see fig. 1). Venting is the direct release of natural gas, including methane, into the atmosphere, and flaring is the combustion of natural gas. Flaring is generally preferable to venting, when feasible, because it can prevent accidental fires or explosions and reduces the climate impact of oil and gas production.

**Figure 1: Sources of Methane Emissions during Oil and Gas Production at Well Sites**

**Production: Associated gas from oil wells**
Operators may need to vent or flare associated gas, including methane, if the well is not connected to a gathering line or if there is not sufficient capacity in existing gas gathering infrastructure.

**Operations: Pneumatic devices**
Pneumatic devices, such as pneumatic controllers and valves, are designed to vent gas. Pneumatic valves open or close to maintain liquid level, pressure, or temperature and are often powered by pressurized natural gas. A small amount of gas is vented each time the valve opens or closes, releasing methane and other gases.

**Storage: Crude oil storage tanks**
When crude oil is transferred to storage tanks, the gas dissolved in the crude oil may vaporize and collect in the space between tank liquids and the top of the tank. Operators may vent these vapors, releasing methane and other gases.

**Leaks: Multiple sources**
Fugitive methane emissions, or leaks, can occur at any stage in the production process and can occur from routine wear and tear or improper installation or maintenance of equipment.

Source: GAO. | GAO-22-104759

Methane emissions can occur in all parts of oil and gas infrastructure, from connections between pipes to storage tanks. The methane emissions that result from oil and gas production can be intentionally released, such as through pneumatic controllers that are designed to vent gas.[13] Methane emissions can also occur from the oil industry as a result of field production operations, such as venting of associated gas from oil wells and oil storage tanks and production-related equipment. Venting can occur through equipment design or operational practices, such as the continuous bleed of gas from pneumatic controllers (that control gas flows, liquid levels, temperatures, and pressures in the equipment), or venting from well completions during production. According to EPA, methane emissions from pneumatic devices powered by natural gas are one of the largest sources of vented methane emissions from the natural gas industry. Methane emissions can also be unintentional. For example, fugitive emissions can occur if a hatch on a tank is accidentally left open. Fugitive methane emissions can also occur due to routine wear and tear or improper installation or maintenance of equipment.

In addition to emitting methane, oil and gas production processes also emit VOCs, a ground-level ozone precursor and contributor to smog. According to an EPA document, many VOCs form ground-level ozone by reacting with oxygen, forming nitrogen oxides and carbon monoxide. However, only some VOCs are considered reactive enough to be of concern and, therefore, subject to EPA's ground-level ozone standards.[14] EPA excludes some hydrocarbons, including methane, from the definition of regulated VOCs because they are less ozone forming than other hydrocarbons. While controls to reduce VOCs reduce methane concurrently, EPA also regulates methane emissions directly because of current and projected greenhouse gas emissions from the oil and gas industry.

[13]According to EPA, pneumatic devices, including pneumatic controllers, are powered by pressurized natural gas and are widely used in the natural gas industry as liquid level controllers, pressure regulators, and valve controllers.

[14]EPA's National Ambient Air Quality Standards for ground-level ozone, or ozone pollution, set a maximum allowed concentration of ozone ($O_3$) that can be present in outdoor air to protect human health and the environment. Each state has to develop a plan for how it will control air pollution, including how the state plans to monitor air quality and strategies the state will use to control for ozone emissions. States are required to implement specific pollution control mechanisms in areas not meeting EPA's ground-level ozone standards, referred to as "nonattainment areas."

## Technologies to Monitor Methane Emissions

Over the past several years, technology companies have developed a wide range of technologies that can help operators detect and determine the source of fugitive emissions of methane from equipment that is not operating normally or properly. Some technologies detect and measure these emissions from oil and gas operations. Examples of these technologies include optical and remote sensors that can be mounted on piloted aircraft, drones, or satellites or deployed as ground-based sensors to provide continuous monitoring. The presented example technologies produce information on methane emissions over different spatial and temporal scales with varying emission detection sensitivities (see fig. 2).

**Figure 2: Technologies Used to Detect Methane Emissions from Oil and Gas Development**

Upper left: A piloted aircraft with a sensor
Upper right: A fixed, continuous monitoring device
Lower left: A drone-based sensor
Lower right: An image captured from a satellite

Sources: Scientific Aviation, Inc. (top left and lower left); GAO (upper right); © 2021 GHGSat Inc. (lower right). | GAO-22-104759

**Optical gas imaging (OGI) cameras.** OGI cameras are handheld instruments that generate infrared images of methane plumes. Leak detection and repair (LDAR) programs that rely on OGI cameras can be labor intensive, since they require inspectors to visit each site or piece of equipment to monitor for emissions.

**Piloted aircraft.** Piloted aircraft, such as airplanes, can be outfitted with various instruments to monitor wind speed, temperature, and methane emissions around areas with oil and gas operations. To collect data and detect and measure emission rates, pilots fly in a predetermined path (such as a circle or a zigzag pattern) around a well site or a basin. Aircraft can cover large areas more quickly than ground crews, which can be useful to operators with well sites that span an entire basin or state.

**Drones.** Drones operate similarly to piloted aircraft but with a sensor that is generally less robust due to the weight thresholds of the platform. Drones outfitted with sensors can hover more slowly and in tighter circles around a well site than piloted aircraft, providing more precise measurements of methane emissions.

**Satellites.** Satellites outfitted with sensors can monitor and detect methane emissions from about 300 miles above the Earth's surface. Satellites do not provide continuous monitoring; rather, satellites can be pointed to a specific geographic area at the request of an operator. Satellites can be useful for operators whose operations are geographically dispersed or for operators who want to monitor specific areas at times when the satellite is overhead.

**Fixed sensors.** Fixed sensors are instruments placed around a well site that can provide continuous monitoring of methane emissions (for example, every few seconds or multiple times a second). Sensors can be placed around the boundaries of a well site to ensure that emissions are detected as the wind shifts direction. Fixed, continuous monitoring sensors can alert operators within minutes of detecting a leak.

# Federal Agencies Have Issued Regulations to Reduce Methane Emissions from Oil and Gas Development, but Implementation Has Been Challenging

EPA and BLM have issued regulations aimed at reducing methane emissions from oil and gas development but encountered administrative and legal challenges in implementing them. Currently, these agencies are in the process of revising regulations to reduce methane emissions in response to directives from recent executive orders.

## EPA and BLM Have Issued Regulations but Faced Administrative and Legal Challenges

### Environmental Protection Agency

EPA is authorized by section 111 of the Clean Air Act to develop performance standards—referred to as new source performance standards (NSPS)—that apply to specific categories of stationary sources that cause or contribute significantly to air pollution, such as the oil and natural gas sector.[15] In 2012, EPA revised the NSPS regulations through a rulemaking for the oil and natural gas sector to further reduce VOC emissions from oil and natural gas sources.[16] Through the control of VOC emissions, methane emissions are also incidentally reduced, yet the 2012 standards in the rule did not directly apply to methane emissions. In 2016, EPA established national standards through a rulemaking to reduce methane emissions under a new Subpart OOOOa regulation and also

[15]The Clean Air Act section 111(b) requires EPA to establish NSPS for categories of stationary sources that the agency determines contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. EPA first promulgated the agency's NSPS for the oil and gas sector in 1985. 50 Fed. Reg. 26122 (June 24, 1985) (codified as amended at 40 C.F.R. Part 60, Subpart KKK); *id.* at 40160 (Oct. 1, 1985) (codified as amended at 40 C.F.R. Part 60, Subpart LLL).

[16]Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews—Final Rule," 77 Fed. Reg. 49490 (Aug. 16, 2012).

expanded VOC emission reduction requirements for a broader range of equipment.[17] These NSPS regulations cover sources that are new, modified, or reconstructed after September 18, 2015.[18] EPA's 2016 standards apply to various segments of the oil and natural gas source category, including oil and natural gas well sites; natural gas production, gathering, and boosting stations; and processing plants, as well as transmission and storage.[19]

EPA implemented the 2016 methane standards but then encountered challenges in continuing to implement methane emissions standards due to administrative actions that occurred in 2020. Specifically, in September 2020, EPA adopted key amendments to Subpart OOOOa in two rulemakings. First, the 2020 Policy Rule rescinded the 2016 methane standards and eliminated all oil and gas NSPS requirements for sources in the transportation and storage segment.[20] In a separate rule issued the next day, which EPA refers to as the 2020 Technical Rule, EPA made several technical amendments to the VOC standards from the 2016 NSPS.[21]

[17]Environmental Protection Agency, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources—Final Rule," 81 Fed. Reg. 35824 (June 3, 2016). When referring to NSPS for methane emissions, this report is referring to 40 C.F.R. Part 60, Subpart OOOOa, 40 C.F.R. §§ 60.5360a, et seq., as contained in the final rule, for the oil and natural gas source category.

[18]Specifically, the NSPS regulations in Subpart OOOOa apply only to covered sources that commence construction, modification, or reconstruction after September 18, 2015. In this report, we refer to all such sources as "new" sources.

[19]In this rule, EPA set standards for specific pieces of equipment, such as pneumatic controllers and compressors. EPA sets NSPS by determining the best system of emission reduction for each source, both for pieces of equipment and industry practices, and translated the best system of emission reduction into a standard of performance. Under the Clean Air Act, the standard may be a numerical emissions limit, expressed as a performance level, such as a 95 percent reduction in emissions. When a numerical standard applies, EPA does not prescribe particular technologies to achieve the required degree of emission limitation. When prescribing or enforcing a numerical standard is not feasible for a source, EPA may instead require specific design, equipment, work practices, or operational standards pursuant to the Clean Air Act section 111.

[20]Environmental Protection Agency, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review—Final Rule," 85 Fed. Reg. 57018 (Sept. 14, 2020).

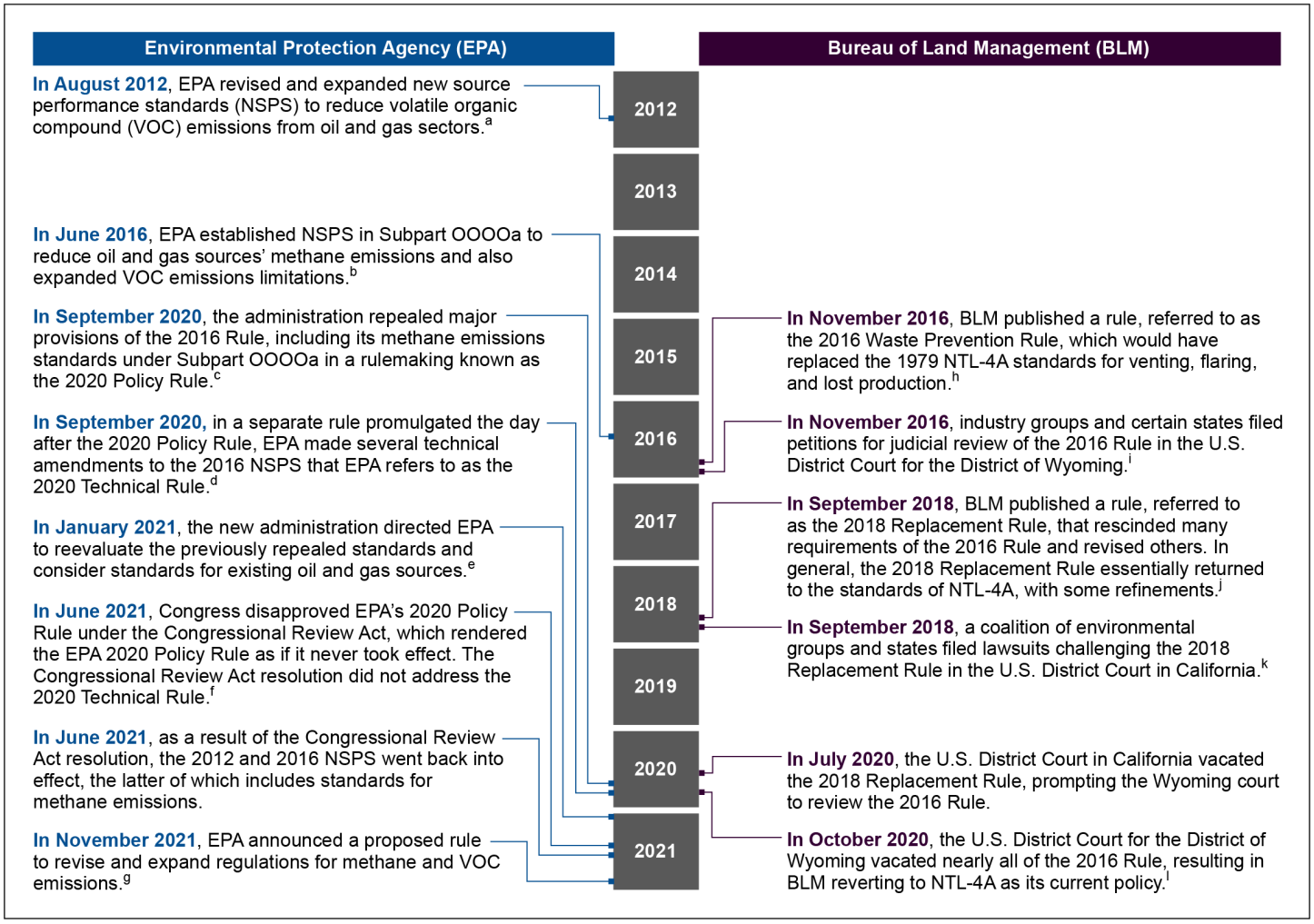
[21]Environmental Protection Agency, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration—Final Rule," 85 Fed. Reg. 57398 (Sept. 15, 2020).

In June 2021, Congress passed and the President signed a resolution of disapproval under the Congressional Review Act for EPA's 2020 Policy Rule, which had the effect of reinstating the 2016 methane standards for the production and processing segments as well as the methane and VOC standards for the transmission and storage segments.[22] The resolution of disapproval did not address the amendments made to the VOC standards by the 2020 Technical Rule. Thus, according to EPA officials, sources are currently required to comply with two sets of standards that differ in certain respects—methane standards based on the 2016 NSPS, and the VOC standards based on the 2016 NSPS, as modified by the 2020 Technical Rule (see fig. 3). Under current methane standards, EPA requires operators to perform semiannual monitoring at well sites, including low production sites, to detect methane emissions.[23] As a part of the semiannual monitoring requirements for methane, operators are required to send personnel to well sites to detect leaks, using handheld equipment specified by EPA.

[22]Joint Resolution, Pub. L. No. 117-23, 135 Stat. 295 (enacted June 30, 2021). When a rule is disapproved under the Congressional Review Act, the agency is prohibited from issuing a rule that is substantially the same going forward. Because of the Congressional Review Act resolution, some sources are now subject to two sets of standards. These sources (such as facilities) may either choose to comply with both sets of standards, which, in most cases, do not conflict. Alternatively, where the standards differ (such as for low production well sites), they are to comply with the more stringent standards, which are typically those in the 2016 NSPS, according to EPA officials. According to an EPA document, sources in the transmission and storage segment are subject to the methane and VOC requirements in the 2016 NSPS if they began construction, reconstruction, or modification after September 18, 2015.

[23]EPA's 2020 Technical Rule created a new subcategory of "low production well sites" for well sites with total production below 15 barrels of oil equivalent per day and exempted such well sites from leak detection and repair requirements for VOC emissions. However, due to the Congressional Review Act resolution, low production well sites are now subject to semiannual methane leak detection and repair requirements under the 2016 NSPS even while they continue to be exempt from leak detection and repair for VOC emissions under the 2020 Technical Rule.

**Figure 3: Time Line of Federal Regulations related to Methane Emissions from EPA and the Department of the Interior's BLM**




Source: GAO analysis of EPA and BLM documents. | GAO-22-104759

[a]77 Fed. Reg. 49490 (Aug. 16, 2012).

[b]81 Fed. Reg. 35824 (June 3, 2016).

[c]85 Fed. Reg. 57018 (Sept. 14, 2020).

[d]85 Fed. Reg. 57398 (Sept. 15, 2020).

[e]Executive Order 13990, 86 Fed. Reg. 7037 (signed Jan. 20, 2021; pub'd Jan. 25, 2021).

[f]Pub. L. No. 117-23, 135 Stat. 295 (enacted June 30, 2021).

[g]86 Fed. Reg. 63110 (Nov. 15, 2021).

[h]2016 Waste Prevention Rule, 81 Fed. Reg. 83008 (Nov. 18, 2016); Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Lessees (NTL-4A), 44 Fed. Reg. 76600 (Dec. 27, 1979).

[i]Wyoming v. U.S. Dep't of the Interior, Case No. 2:16-cv-00285-SWS (D. Wyo.).

[j]83 Fed. Reg. 49184 (Sept. 28, 2018).

[k]California v. Bernhardt, Case No. 4:18-cv-05712-YGR (N.D. Cal.).

[l]Wyoming v. U.S. Dep't of the Interior, 493 F. Supp. 3d 1046 (D. Wyo. 2020); BLM Information Bulletin 2021-003 (Oct. 22, 2020).

## Bureau of Land Management

BLM issued a rule in 2016 that helps to reduce methane emissions from oil and gas production on federal onshore oil and gas leases but, due to a series of administrative actions and legal challenges, BLM did not fully implement it. BLM adopted the 2016 Waste Prevention Rule that included measures for reducing waste of natural gas during production, thereby also reducing emissions of air pollutants, including methane. Such measures included further limiting routine gas flaring and reducing venting, requiring operators to prepare plans for gas capture and waste minimization and adopting measures for detecting leaks.[24] The 2016 rule was intended to replace requirements in place since 1979 in the Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases (NTL-4A).[25] However, the 2016 rule was not implemented, following a subsequent 2018 BLM rule that substantially revised it.[26] Later, a 2020 legal ruling vacated nearly all of the 2016 rule's provisions on the basis that BLM's purpose and justification for the rule exceeded its statutory authority, among other defects.[27] BLM officials told us that managing uncertainty over the agency's statutory authority is a regulatory challenge for the agency.

Due to these revisions and legal rulings, major provisions of NTL-4A are still in effect, such as those that govern venting, flaring, and avoidably or unavoidably lost production from BLM-managed leases. However, NTL-4A does not specifically mention methane. Under NTL-4A, venting or flaring of gas is generally prohibited. But NTL-4A also provides a number of exemptions to this prohibition, both for short-term or emergency venting or flaring and for venting or flaring for longer periods, if operators obtain supervisory approval in advance. NTL-4A has criteria to determine

[24]81 Fed. Reg. 83008 (Nov. 18, 2016).

[25]44 Fed. Reg. 76600 (Dec. 27, 1979). The U.S. Geological Survey issued NTL-4A in 1979, before BLM assumed oversight responsibility for federal onshore oil and gas development and production.

[26]On September 28, 2018, BLM issued a final rule substantially revising the 2016 rule, 83 Fed. Reg. 49184 (Sept. 28, 2018). On July 15, 2020, a California court vacated BLM's 2018 Rule. California v. Bernhardt, 472 F. Supp. 3d 573 (N.D. Cal. 2020).

[27]Wyoming v. U.S. Dep't of the Interior, 493 F. Supp. 3d 1046 (D. Wyo. 2020).

whether gasses lost through venting or flaring are “unavoidably lost,” and, thus, royalty free, or “avoidably lost” and, therefore, subject to royalties.[28]

## EPA and BLM Are Revising Regulations to Reduce Methane Emissions

EPA and BLM are in the process of revising their regulations to reduce methane emissions in response to directives from recent executive orders. Specifically, Executive Order 13990 directed EPA to consider issuing proposed rules by the end of September 2021 to both revise standards for methane emissions from new oil and gas sources and to establish standards for methane emissions from existing oil and gas sources, which are currently unregulated for methane.[29] In November 2021, EPA announced a proposed rule to regulate both new and existing sources and to require operators to replace emitting pneumatic controllers with nonemitting ones, among other things.[30] In addition to EPA’s November 2021 proposed rule, EPA intends to issue a supplemental proposal in 2022 that may expand on or modify the 2021 proposal. As part of this effort, EPA is seeking information through the public comment process about additional sources of pollution that may help EPA further reduce methane and VOC emissions, such as from abandoned and unplugged wells. EPA plans to issue a final rule before the end of calendar year 2022.

BLM officials are also developing a proposed rulemaking to address the priorities identified in Executive Orders 13990 and 14008, such as reducing methane emissions in the oil and gas sector and addressing climate change.[31] In spring 2021, BLM announced its proposal to update the agency’s current rules governing the venting and flaring of methane from onshore oil and gas leases. According to agency officials, BLM is

[28]For example, venting or flaring gas vapors released from storage tanks or low-pressure production vessels is generally considered unavoidably lost, and no royalties are due. However, BLM may determine that vented or flared gas is avoidably lost if the losses are due to negligence or failure to take reasonable measures to prevent or to control the losses, among other issues.

[29]Executive Order 13990, “Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis,” 86 Fed. Reg. 7037 (signed Jan. 20, 2021; pub’d Jan. 25, 2021).

[30]EPA also states that the proposed rule will strengthen requirements for storage tanks, eliminate venting of associated gas, require operators to route the gas to a sales line when available, and broaden the types of pneumatic pumps covered by the rule.

[31]Executive Order 14008, “Tackling the Climate Crisis at Home and Abroad,” 86 Fed. Reg. 7619 (signed Jan. 27, 2021; pub’d Feb. 1, 2021); Executive Order 13990, “Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis,” 86 Fed. Reg. 7037 (signed Jan. 20, 2021; pub’d Jan. 25, 2021).

considering revising its rulemaking to require operators to install no-bleed or low-bleed pneumatic controllers; to install vapor recovery units on storage tanks; to require operators to flare rather than vent gas when possible; and to require operators to submit waste minimization plans, among other policies. According to agency documents, BLM planned to issue a proposed rule in March 2022; however, as of April 2022, it has not been published in the Federal Register.

## Industry Is Taking Actions to Reduce Methane Emissions from Oil and Gas Development, but Federal Regulations Limit Use of Alternative Technologies

Several selected industry entities are voluntarily taking actions to reduce methane emissions from oil and gas development, including through voluntary measures such as replacing older, leaky equipment; using alternative methane detection technologies; and participating in industry- and EPA-led methane reduction initiatives. However, EPA's process for reviewing proposed alternative technologies for detecting methane emissions may limit adoption of these technologies by industry.

### Industry Is Voluntarily Taking Actions to Reduce Methane Emissions from Oil and Gas Development

Several selected industry entities are voluntarily taking actions to reduce methane emissions from oil and gas development, according to their representatives.[32] These include actions, such as

- replacing older, leaky equipment;
- using alternative technologies to detect methane emissions, in addition to those required by EPA; and
- participating in industry- and EPA-led methane reduction initiatives.

Representatives from several industry entities and stakeholders we spoke with told us that some operators are replacing or retrofitting older equipment designed to vent gas while operating normally, such as high-bleed pneumatic controllers, with newer devices that have little to no

[32]The representatives we spoke with, representing 11 selected industry entities in total, include U.S. oil and natural gas operators, industry groups, and technology companies. We also spoke with five stakeholders that include academics, environmental organizations, and national coalitions. When referring to the number of entities we spoke with in the report, we used the term "some" to refer to two industry entities and stakeholders and "several" to refer to three or more entities and stakeholders.

emissions. For example, one entity has retrofitted high-bleed pneumatic controllers with no-bleed pneumatic controllers and is using compressed air instead of natural gas to operate the controllers, according to its representatives.

Several entities use alternative technologies to detect methane emissions, in addition to using OGI cameras and Method 21 instruments that EPA requires for semiannual LDAR inspections at well sites, according to their representatives.[33] For example, one entity has deployed and evaluated several alternative methane detection technologies at well sites, including drone-based sensors and other sensors placed on mobile platforms such as automobiles, according to its representatives. According to representatives from another entity, monitoring oil and gas sites from the air is significantly faster than monitoring for leaks with ground crews that are equipped with handheld instruments, such as OGI cameras and Method 21 instruments. Aerial monitoring also enables ground crews to prioritize and fix the largest leaks, according to representatives from one entity. Another entity currently uses aircraft to monitor and detect emissions and is evaluating alternative technologies, such as continuous monitoring and ground-based sensors, according to its representatives.

Environmental and economic considerations informed some entities' decisions to take actions that go beyond what EPA requires, according to their representatives. For example, external stakeholders, such as company shareholders, are becoming more concerned with the environmental impacts of oil and gas development and the effects of climate change, according to representatives from one entity we spoke with. To address these concerns, the entity implemented methane reduction strategies. These representatives also told us that reducing emissions is important for economic reasons because it means the operator is capturing gas that can then be sold.

Some operators are also participating in voluntary industry-led and EPA-led methane reduction initiatives. For example, the American Petroleum Institute's Environmental Partnership provides a forum for members of the oil and natural gas industry to share information and analyze best practices and technologies to reduce methane emissions. According to

[33]Method 21 is not a specific type of instrument, but specifications and performance criteria that instruments must follow to measure VOC emissions concentrations, such as the device being readable to ±2.5 percent of the specified leak definition concentration.

the Environmental Partnership's 2021 annual report, there were 94 participating operators, representing over 70 percent of onshore oil and gas production.[34] In addition, EPA's voluntary Natural Gas STAR program provides a framework for operators in the U.S. oil and natural gas industry to implement methane reduction technologies and practices and document their voluntary emission reduction activities. By joining the program, operators commit to evaluating and implementing cost-effective methane emission reduction strategies. According to EPA, as of 2020, there were 93 U.S. oil and gas operators participating in the program.

In 2016, EPA launched a second partnership program: the Methane Challenge program. This program provides partner companies a platform to make a company-wide commitment to cut methane emissions, track and report their actions, and be recognized by EPA for their achievements. Companies can either commit to implementing best management practices on specific methane emission sources within 5 years or commit to achieving a specific methane emission intensity by a certain date, or commit to both options. According to EPA, as of 2020, there were 69 U.S. oil and gas operators participating in the Methane Challenge program across both commitment options.

Representatives from several entities cited the cost of implementing methane reduction strategies and retrofitting facilities to reduce emissions. For example, it might not be economically feasible to retrofit an older, low-producing facility because the cost may be greater than the facility is worth, according to one entity's representatives. However, the representatives also stated that methane emissions detection and reduction could be cost effective, even for smaller operators, because operators can sell the gas they capture. Small operators might not be able to afford the cost to implement methane reduction strategies, such as replacing pneumatic controllers, according to representatives from three entities and one stakeholder. However, representatives from one entity told us that smaller operators participate in initiatives such as the Environmental Partnership, which has no membership fee and identifies cost-effective strategies that operators can take to reduce methane emissions.

[34]The Environmental Partnership, *Annual Report 2021, Improving the Oil and Natural Gas Industry's Environmental Performance* (2021).

## Federal Regulations Limit Use of Alternative Technologies for Methane Detection

We found that federal regulations can impede operators' adoption of alternative technologies for detecting methane emissions from oil and gas development, such as for aircraft and ground-based sensors. Congress established a process—alternative means of emission limitation (AMEL)—under the Clean Air Act that allows anyone to submit applications to EPA to request approval of an alternative technology that will achieve at least an equivalent reduction in emissions.[35] EPA then developed regulations, which further describe the AMEL process for approving alternative technologies to detect fugitive emissions of methane and VOCs from well sites.[36] If approved by EPA, these alternative technologies could be used in place of the technologies mandated under NSPS Subpart OOOOa—an OGI camera or Method 21 instrument—for semiannual LDAR inspections at well sites. EPA's approval of an alternative technology through AMEL requires that the associated levels of emissions reduction be equal to or better than the mandated technologies. As part of an approval, EPA would prescribe other necessary requirements, including the frequency of inspections, time lines for repairs, and quality assurance control measures, EPA officials stated.

To obtain approval under AMEL, an applicant must provide information that would allow EPA to determine that the alternative technology results in an emissions reduction at least equivalent to those achieved under NSPS Subpart OOOOa. Under the 2020 Technical Rule, EPA requires field data showing seasonal variations in order for EPA to determine the method detection limit for alternative technologies.[37] Applicants can include multiple oil and gas sites within one application and can supplement field data with test data, modeling analyses, and other documentation.

[35]42 U.S.C. § 7411(h)(3).

[36]40 C.F.R. § 60.5398a. As noted above, EPA may set an NSPS by translating a best system of emissions reduction into a numerical emissions limit, but when that approach is not feasible, EPA may instead require a specific design, equipment, work practice, or operational standard. In this latter situation, an operator may seek approval of an AMEL. EPA amended the AMEL process in its 2020 Technical Rule for requesting the use of an AMEL for well completions. Additionally, the November 2021 proposed rule would allow operators to use alternative technologies to detect large leaks but would still require screenings with OGI cameras or Method 21 instruments at a lesser frequency. In contrast, an operator could use the AMEL process to obtain approval to use an alternative technology instead of OGI cameras or Method 21 instruments.

[37]40 C.F.R. § 60.5398a(c).

Representatives from several industry entities and stakeholders we spoke with said that they experienced challenges in meeting EPA's requirements for AMEL approval for an alternative methane detection technology. For example, according to representatives from one industry entity, collecting field data and modeling analyses at each site to demonstrate that an alternative technology is as effective as, or better than, what EPA requires is time and resource intensive. The representatives said that EPA should allow approved AMELs to apply more broadly to multiple sites, such as for all wells in an oil and gas basin.

In EPA's rulemaking for the 2020 Technical Rule, EPA collected and summarized public comments in response to the rule. The public comments indicated that the requirements to approve alternative technologies on a site-specific basis were onerous and that they would stifle development of innovation in new technology. One commenter noted that its customers have indicated that they would not apply for an AMEL if approval were site specific. Representatives from five industry entities and three stakeholders we spoke with emphasized that regulations should allow for flexibility in the types of technologies for monitoring and detecting methane emissions.

Further, EPA's Fiscal Year 2018-2022 Strategic Plan states that EPA is to develop and evaluate cost-effective, innovative, and sector-based approaches to prevent and reduce pollution.[38] According to the plan, EPA will pursue innovative technologies and will determine how it can most effectively harness and benefit from the recent, rapid development of environmental monitoring technologies. Despite EPA's commitment to innovative approaches as expressed in its strategic plan, the current AMEL process does not include flexibilities that take into account rapidly changing technology or the practical difficulties of gathering data across large geographic areas. According to EPA officials, the agency has been generally open to the idea of broad approval of an alternative, if presented with sufficient information. In addition, in response to the public comments from the 2020 rulemaking, EPA states that alternative technology for monitoring emissions could be approved for wider use, if it makes it through the rulemaking process.[39] However, as of November

[38]Environmental Protection Agency, "Working Together, FY 2018-2022 U.S. EPA Strategic Plan" (February 2018, updated September 2019).

[39]85 Fed. Reg. 57398, 57423, 57430 (Sept. 15, 2020).

2021, EPA has received one AMEL application under NSPS Subpart OOOOa, despite the process being in place since 2016.[40] Without greater flexibility in the process for approving alternative technologies, EPA may hinder the adoption of innovative approaches for detecting and reducing methane emissions by oil and gas operators.

## Selected States Are Taking Steps to Regulate Methane Emissions from Oil and Gas Development, Which Could Inform Federal Regulations

Seven selected states have enacted regulations to reduce methane emissions from oil and gas well sites, including to regulate existing sources of oil and gas, require operators to regularly monitor for leaks and conduct repairs, and require operators to replace or retrofit certain equipment that vents methane or VOCs with low or nonemitting equipment.[41] Certain states whose regulations we reviewed also require operators to submit gas capture plans prior to receiving an approved permit to drill, which BLM does not require. These state gas capture plan requirements, some of which include gas capture targets, could inform federal rulemaking.

### Selected States Are Working to Reduce Methane Emissions through Regulating Existing Oil and Gas Sources, Detecting Leaks, and Undertaking Equipment Maintenance

The seven states whose regulations we reviewed are taking a variety of regulatory actions to reduce methane emissions from well sites within their borders, including those necessary to meet EPA's ground-level ozone standards.[42] Some states do so by directly regulating methane emissions from oil and gas development or indirectly regulating it through regulation of VOCs.

One state—Texas—regulates VOC emissions but does not regulate methane directly, from well sites, according to state officials. According to a stakeholder we interviewed, regulating methane directly captures more sources across the entire oil and gas industry than regulating VOCs.[43] Five states—California, Colorado, North Dakota, Pennsylvania, and

[40]As of November 2021, EPA has not yet approved this AMEL application.

[41]For more information on how we selected states, see app. I.

[42]As previously mentioned, states are required to implement specific pollution control mechanisms in areas not meeting EPA's ground-level ozone standards. We reviewed regulations related to methane for seven states with high oil and gas production: California, Colorado, New Mexico, North Dakota, Pennsylvania, Texas, and Wyoming. For more information on our scope and methodology, see app. I.

[43]According to the stakeholder we interviewed, methane—not VOCs—comprises emissions in the transportation and storage segment (i.e., downstream operations).

Wyoming—regulate methane emissions directly, in addition to regulating VOC emissions from well sites. For example, officials in California told us that the purpose of the state's 2017 regulation was to address methane emissions that were not covered by the local air districts' VOC rules.[44] Similarly, a Colorado official told us that after the state passed a regulation in 2005 in response to nonattainment of EPA's ground-level ozone standards, the state revised its regulation to include oil and gas development statewide and later revised it again to include specific requirements on methane as well as VOCs.[45]

Six states—California, Colorado, New Mexico, North Dakota, Pennsylvania, and Wyoming—regulate existing sources of oil and gas development. Officials from California told us that the majority of the state's oil and gas infrastructure is preexisting and that there is not a lot of new infrastructure planned, which would be subject to NSPS Subpart OOOOa. According to these officials, introducing federal regulations that apply to existing sources, instead of only to new ones, would result in all states following the same baseline level of requirements. In addition, an official from Colorado told us that the state implemented rules for existing oil and gas locations in a phased approach, allowing operators to request permission to flare produced natural gas for up to 12 months following the effective date of the amended rules (January 15, 2021), after which operators must stop flaring by January 15, 2022. See table 1 for more information on state regulatory requirements to reduce methane emissions.

[44]According to California officials, the state directly regulates methane but not VOCs. Many of the local air districts in California have LDAR rules that directly regulate VOCs.

[45]According to a Colorado official, the state's first explicitly methane-directed regulation was adopted in 2014. Since then, the state has sought to evaluate both the VOC and methane emissions benefits of proposed oil and gas regulations.

**Table 1: Selected State Regulatory Requirements to Reduce Methane Emissions**

| | Regulate methane or volatile organic compounds (VOCs) | State regulation of existing sources | State leak detection and repair (LDAR) program | Requirements for equipment |
|---|---|---|---|---|
| California | Methane and VOCs[a] | ☑ | ☑ | ☑ |
| Colorado | Methane and VOCs | ☑ | ☑ | ☑ |
| North Dakota | Methane and VOCs[b] | ☑[c] | ☑[d] | ☐ |
| New Mexico[e] | - | ☑ | ☐ | ☐ |
| Pennsylvania[f] | Methane and VOCs | ☑ | ☑ | ☑ |
| Texas | VOCs | ☐ | ☑[g] | ☐ |
| Wyoming | Methane and VOCs | ☑[h] | ☑ | ☑ |

Source: GAO analysis of state documents and information provided by state officials. | GAO-22-104759.

[a]California officials told us that statewide regulation directly regulates methane but not VOCs. According to these officials, many of the local air districts in California have LDAR rules that directly regulate VOCs.

[b]A North Dakota official told us that the state regulates VOCs and methane through provisions in N.D. Admin. Code 33.1-15-07, which apply to organic compounds gases and vapors. According to the state official, North Dakota has interpreted organic compounds gases and vapors as including all organic compounds, including methane and other organic compounds.

[c]A North Dakota official told us that all sources have been subject to control requirements since the 1980s, when the provisions currently codified at N.D. Admin. Code 33.1-15-07 became effective.

[d]A North Dakota official told us that the state has an LDAR program aside from referencing the Environmental Protection Agency's new source performance standards Subpart OOOO and OOOOa LDAR requirements.

[e]According to a state official, the New Mexico Environment Department is drafting proposed rules that would regulate VOCs and establish an LDAR program as well as requirements for equipment. A state official told us that they expected the rules to be final by June 2022 but that there was uncertainty regarding that time frame.

[f]According to a state official, Pennsylvania's Department of Environmental Protection is developing rules that would regulate VOCs and existing sources and have equipment requirements. Officials expect the rule to become final in mid-2022.

[g]Texas requires LDAR in areas that do not meet EPA's ground-level ozone standards.

[h]Wyoming regulates certain oil and gas well sites located in the Upper Green River Basin ozone nonattainment area that exist as of January 1, 2014.

Six states—California, Colorado, North Dakota, Pennsylvania, Texas, and Wyoming—require operators to conduct LDAR activities with EPA-approved methods or devices or, in the case of Colorado, a state-approved alternative. For example, Wyoming requires operators of certain oil and gas well sites to monitor for leaks of VOCs at least quarterly. Such monitoring may consist of Method 21 instruments, an OGI camera, other instrument-based technologies, or audiovisual olfactory inspections. In addition, Colorado officials told us that the state adopted LDAR requirements in 2014 for production facilities to periodically monitor components using Method 21 instruments, an OGI infrared camera, or a state-approved alternative method and to repair detected leaks and

maintain associated records.[46] Colorado regulations require operators of well production facilities in Colorado to conduct monthly audiovisual olfactory inspections unless a facility is subject to monthly LDAR.[47] According to the Colorado Department of Public Health & Environment's 2020 annual report, its LDAR program resulted in operators identifying 18,824 leaks in 2020 and repairing 18,665 (about 99 percent) of those leaks.

Four states—California, Colorado, Pennsylvania, and Wyoming—require operators to replace or retrofit certain equipment that vents methane or VOCs during normal operations with low- or nonemitting equipment to help reduce methane emissions. A Colorado official told us that changes to the state's regulation in February 2021 address pneumatic controllers, which are major sources of emissions from oil and gas development. Colorado regulations require operators to replace or retrofit high-bleed pneumatic controllers with nonemitting controllers.[48] Officials told us that both industry and environmental groups supported this change and that the Colorado Air Quality Control Commission unanimously approved it.

[46]According to a Colorado official, Colorado's regulation offers a pathway for operators to submit alternative monitoring technologies or programs for approval for LDAR. The official told us that the state developed criteria for approving alternatives and have approved two alternatives for LDAR to date, one of which is a continuous monitoring system using OGI infrared cameras. According to the official, in 2017, Colorado formally included criteria for approving alternative monitoring technologies or programs in its regulation. The official told us that this action was in response to EPA's request that Colorado integrate its alternative technology or program approval criteria into its state plan for meeting EPA's ground-level ozone standards. According to the official, using alternative monitoring technologies or programs in areas of the state that have not met EPA's ground-level ozone standards must now receive Colorado approval and be submitted to EPA for review. Use of alternative monitoring technologies or programs in areas of the state that are meeting EPA's ground-level ozone standards are not subject to EPA review, if approved by Colorado, according to the official.

[47]According to a state official, in some cases audiovisual olfactory inspections are required weekly.

[48]According to Colorado's Regulation No. 7, high-bleed pneumatic controllers are designed to have a continuous bleed rate in excess of 6 standard cubic feet per hour of natural gas to the atmosphere. Low-bleed pneumatic controllers are designed to have a continuous bleed rate that emits less than or equal to 6 standard cubic feet of natural gas to the atmosphere. Nonemitting pneumatic controllers do not use hydrocarbon gas as the valve's actuating gas and, therefore, do not emit any natural gas.

Similarly, Wyoming requires low-bleed, no-bleed, or intermittent pneumatic controllers for new or modified facilities.[49]

## Certain States Require Operators to Capture Methane, but BLM Regulations Do Not

Colorado, New Mexico, and North Dakota are taking various actions to require operators in their states to capture gas. These actions include prohibiting venting or flaring produced natural gas, instituting enforceable gas capture targets, and requiring operators in their states to submit plans to capture gas when applying for a new drilling permit to avoid emissions from gas that operators would otherwise vent or flare.[50] For example, as part of Colorado's recent rule on venting and flaring for new wells, the state requires operators to (1) commit to connecting to a pipeline by the time production starts; (2) submit a gas capture plan to connect the facility to a natural gas gathering (pipeline) system; or (3) submit a plan to put the gas to beneficial use, such as to generate electrical power.[51] Colorado rules state that venting and flaring of natural gas represent a waste of an important energy resource and pose safety and environmental risks, and the state prohibits venting and flaring except under certain circumstances.[52] Operators in Colorado must also verify that their facility has been connected to a gathering line, or the state may require the operators to shut in their wells until they are connected or the gas is put to beneficial use.

Similarly, New Mexico's 2021 rule on venting and flaring requires operators to provide a natural gas management plan with each drilling permit for a new or recompleted well. Starting in April 2022, plans must include the existing gas gathering system that the operator has contracted or anticipates contracting with, or the operator's plans for

[49]According to Wyoming's Oil and Gas Production Facilities permitting guidance, intermittent vent pneumatic controllers are designed to vent noncontinuously. In addition, according to state officials, the guidance requires operators to replace or retrofit equipment for new or modified sources. It does not impose requirements on existing sources to replace or retrofit equipment.

[50]According to state officials, state gas capture plan requirements apply to operators on state, private, and federal lands and, in some cases, apply to operators on tribal lands.

[51]According to the Department of Transportation's PHMSA, gathering lines are pipelines that are used to transport crude oil or natural gas from the production site (wellhead) to a central collection point. They generally operate at relatively low pressures and flow and are smaller in diameter than transmission lines.

[52]According to a state official, the state provides limited duration exceptions for upset conditions, certain maintenance and repair activities, production evaluations or productivity tests, bradenhead testing, and certain well liquids unloading events. The state also sets reporting requirements for those listed venting or flaring events.

connecting the well to a gas gathering system. The state also requires operators to capture no less than 98 percent of the gas they produce by the end of calendar year 2026 by annually increasing the percentage of gas captured each year to reach 98 percent. New Mexico state officials told us that under the rule, the state can deny permits if the operators do not submit an adequate plan that shows that the operators are meeting their gas capture percentages. State officials told us that New Mexico's previous gas capture plan requirement did not have a mechanism for denying drilling permits.

North Dakota has taken various actions to require operators in its state to capture gas. These actions include (1) instituting enforceable gas capture targets and (2) requiring operators in its state to submit plans to capture gas when applying for a drilling permit to avoid emissions from gas that operators would otherwise vent or flare.[53] North Dakota's 2014 order establishes percentage goals for capturing gas that increase annually. If an operator is unable to attain the goals, the state can restrict the well's production and issue civil penalties. According to a North Dakota official, in 2018, the state amended the gas capture requirement to allow operators that are meeting targets to forgo a capture plan with their drilling permit applications. That official indicated that, effective November 1, 2020, the gas capture percentage increased to 91 percent. Any operator failing to meet gas capture goals must submit a gas capture plan for all applications for a permit until the operator meets the gas capture goal for 3 consecutive months, according to the official.

In contrast, BLM does not require operators on federal lands to submit gas capture plans. Under BLM's 2016 Waste Prevention Rule, operators were required to submit waste minimization plans when applying for a permit to drill a new well. The rule required operators to plan for how they would capture produced gas before drilling, including, in some cases, identifying gas pipelines to transport the gas. However, as described earlier, the rule was revised by a 2018 rule, then largely vacated in 2020, and BLM never implemented the gas capture requirement, due to legal challenges. BLM officials told us in September 2021 that the agency has initiated a rulemaking and is considering requiring operators to submit waste minimization plans for all drilling permits. BLM officials told us in

[53]According to a state official, any operator failing to meet gas capture goals must submit a gas capture plan when applying for a drilling permit. Also, a sworn affidavit must be filed that the operator has provided a gas production forecast to the midstream gas gathering company and developed a gas capture plan for increased density, temporary spacing, and proper spacing hearings.

October 2021 that the waste minimization plans would not include gas capture percentage targets because that goes beyond the purpose of the plans, which is to specify circumstances when gas can be lost royalty free.

BLM regulations address the waste of mineral resources on federal lands. Specifically, BLM's mineral leasing and development process was established under the Mineral Leasing Act of 1920, as amended, which requires lessees to use all reasonable precautions to prevent waste of oil or gas developed on the lands. The Mineral Leasing Act also states that each lease shall contain provisions for insuring the exercise of reasonable diligence, skill, and care in the operation of said property, and that the prevention of undue waste shall be observed. Venting and flaring gas constitutes a lost resource that contributes to methane emissions. Similarly, according to a state regulation, venting and flaring represents a waste of an important energy resource, which an industry representative said operators could sell. Without taking steps to prevent lost gas, such as considering whether to require gas capture plans from operators of leases on federal lands during production, BLM is potentially forgoing revenue from wasted gas, which contributes to pollution and greenhouse gases.

The gas capture plans required by certain states could serve to inform BLM's rulemaking. For example, one state official we spoke with told us that the federal government could require commitments from operators to connect to pipelines before it approves any permits to drill on federal lands. Similarly, a stakeholder told us that the federal government could require operators to connect to a pipeline before they began drilling, which would reduce emissions as well as wasted gas, a potential source of royalties for BLM. In addition, another stakeholder told us that currently, operators are pumping oil and bringing it to market, but they must flare associated gas because they do not have a way to transport it. According to the stakeholder, federal regulations could help mitigate this practice, for example, by banning flaring and not allowing drilling on federal lands if there is insufficient infrastructure to capture gas.

## Conclusions

Methane is a substantial contributor to global greenhouse gas emissions, results in air pollution, and constitutes a lost source of revenue for the federal government when emitted from sources on federal lands. While EPA and BLM have taken steps in an array of rules to reduce methane emissions, administrative and legal challenges have hindered their implementation. In the midst of federal uncertainty, the oil and gas industry is voluntarily taking actions to reduce methane emissions, but

federal regulations can impede adoption of alternative technologies for detecting methane emissions. Without greater flexibility in its process for approving alternative technologies, EPA may hinder the adoption of innovative approaches by operators for detecting and reducing methane emissions. Large oil- and gas-producing states are taking steps to regulate methane that go beyond what BLM demands, such as requiring operators to submit gas capture plans prior to drilling and to establish and meet goals for gas capture. Without BLM taking steps to institute similar requirements for operators on federal lands, operators will continue to vent or flare methane that contributes to pollution and greenhouse gas emissions, and the federal government will continue to lose revenues from the production of oil and gas.

## Recommendations for Executive Action

We are making the following two recommendations:

The EPA Administrator should provide greater flexibility to operators for using alternative technologies to detect methane emissions. (Recommendation 1)

The Director of BLM should consider whether to require gas capture plans that are similar to what states require, including gas capture percentage targets, from operators on federal lands. (Recommendation 2)

## Agency Comments and Our Evaluation

We provided a draft of this report to EPA and Interior for review and comment. In its comments, reproduced in appendix III, EPA concurred with our recommendation and provided technical comments, which we incorporated as appropriate. Interior provided verbal concurrence with our recommendation, but did not provide a formal comment letter in time for inclusion in this report.

As agreed with your offices, unless you publicly announce the contents of this report earlier, we plan no further distribution until 30 days from the report date. At that time, we will send copies to the appropriate congressional committees, the Administrator of the Environmental Protection Agency, the Secretary of the Interior, and other interested parties. In addition, the report will be available at no charge on the GAO website at https://www.gao.gov.

If you or your staff have any questions about this report, please contact me at 202-512-3841 or ruscof@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. GAO staff who made key contributions to this report are listed in appendix IV.

Frank Rusco
Director, Natural Resources and Environment

# Appendix I: Objectives, Scope, and Methodology

This report (1) describes the steps that federal agencies have taken to reduce methane emissions from oil and gas development, and the implementation challenges that agencies have faced; (2) examines actions that selected industry entities are taking to reduce methane emissions from oil and gas development and the extent to which federal regulations affect industry response; and (3) examines how selected states regulate methane emissions from oil and gas development and the extent to which those efforts could inform federal actions.

To describe the steps that federal agencies have taken to reduce methane emissions and the challenges they faced, we reviewed prior federal regulations and other documentation on actions taken by the Department of the Interior and the Environmental Protection Agency (EPA).[1] These include proposed and final rules, regulations, guidance documents and fact sheets on methane emissions from oil and gas development, and technology requirements for oil and gas operators to reduce emissions. We also reviewed the regulatory and legal history of efforts to reduce methane emissions starting in 2012 for both agencies. We interviewed federal officials from Interior and EPA on regulations related to methane emissions, what changes occurred since 2012, and anticipated proposed rulemaking. We also interviewed these officials to obtain information about the requirements for leak detection and repair, and any technologies the agencies require operators to use to detect leaks at oil and gas sites.

To examine the actions that selected industry entities are taking to reduce methane emissions from oil and gas development and the extent to which federal regulations affect industry response, we analyzed documentation on the industry efforts of a nongeneralizable sample of 11 industry entities.[2] Industry entities included oil and gas operators, industry groups, and technology companies. Specifically, we analyzed operators' annual

[1]The Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) regulates pipeline safety, including releases from certain oil and gas pipelines. Given that the focus of this review is on upstream oil and gas activities rather than transportation facilities, we did not include PHMSA in the scope of this review. PHMSA officials report that, in response to the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act (PIPES Act) of 2020, PHMSA is developing regulations to reduce emissions but that PHMSA does not currently have any express methane emissions regulations in effect. PHMSA officials also stated that other rulemaking efforts could affect methane emissions by reducing the frequency or severity of gas pipeline incidents.

[2]Of the 13 industry entities we selected, we were unable to contact two to interview. We therefore interviewed 11 of the remaining selected industry entities.

reports and reports from EPA- or industry-led initiatives. Industry entities included oil and gas operators that use methane reduction technologies in their operations, industry groups that represent the interests of oil and gas operators, and technology companies that develop methane reduction technologies.

We identified these entities through interviews with federal agencies, academics, and industry as those familiar with and conducting activities to reduce methane emissions from oil and gas development. From the list of industry entities we identified, we selected 11 to interview that provided a range of methane reduction technologies, operator size, and interests. We conducted semistructured interviews with representatives from selected industry entities to clarify and confirm information from the documentation we obtained. When referring to the number of entities we spoke with in the report, we used the term "some" to refer to two entities, and "several" to refer to three or more entities. We also reviewed methane detection technology requirements in EPA's regulations and the agency's pollution reduction approaches laid out in its most recent strategic plan.[3] Because this was a nongeneralizable sample, our findings are not generalizable to other industry entities we did not include in our review but provide information on what efforts are underway within major sectors of the oil and gas industry to reduce methane emissions.

We also analyzed documentation and interviewed a nongeneralizable sample of five stakeholders to provide additional perspectives on industry actions to reduce methane emissions and the extent to which federal regulations affect industry response.[4] Stakeholders included two academics that research how to reduce methane emissions, two environmental groups that research efforts to reduce methane emissions and provide input on proposed federal and state regulations, and one national coalition that advises state environmental regulatory agencies about federal and state methane regulations.

We analyzed documentation from stakeholders, including academic studies identified in a literature search. We identified these stakeholders through the literature search and interviews with federal agencies,

[3]40 C.F.R. §§ 60.5397a, 60.5398a (2019). Environmental Protection Agency, "Working Together, FY 2018-2022 U.S. EPA Strategic Plan" (February 2018, updated September 2019).

[4]Of the six stakeholders we selected, one indicated that it did not have recent work on methane emissions and declined to be interviewed. We therefore interviewed five of the remaining selected stakeholders.

academics, and industry as conducting research on efforts to reduce methane emissions and being knowledgeable about federal and state regulations. To identify existing studies from sources including peer-reviewed journals, conference papers, and dissertations, we conducted searches of ProQuest and Scopus databases. We performed these searches and identified 169 publications from January 2016 to April 2021. We further limited our review to studies that informed various subject areas, including (1) quantification of methane emissions; (2) methane detection technology keywords such as aerial, satellites, and lasers; and (3) industry initiative discussions.

In addition, we performed an initial in-depth review of the findings and methods, and then a GAO senior general engineer with experience in the petroleum industry performed an independent review of the studies we identified, using the same criteria described above. Based on these criteria, we selected nine peer-reviewed studies, seven of which we could locate, that were relevant and applicable to our report. In order to ensure that the methodologies of these studies were sound, we reviewed the authors' approach in detecting and measuring methane emissions and the various factors they considered, such as the types of detection technologies used, the limits of their detection and measurement techniques, and their cost-effectiveness. We determined that their methodologies were sufficiently sound for assisting the team in identifying academics to interview.

From the list of stakeholders we identified, we selected five to interview that studied a range of methane reduction technologies and published reports on methane emissions reduction efforts. We conducted semistructured interviews with selected stakeholders to clarify and confirm information from the documentation we obtained. In interviews with representatives from selected industry entities and stakeholders, we used standard sets of questions but also discussed specific industry and stakeholder perspectives, as appropriate. Because we selected a sample of industry entities and stakeholders, our findings are not generalizable to other industry entities and stakeholders not included in our review but provide some information on industry efforts to reduce methane emissions and any challenges in doing so.

To examine how selected states regulate methane emissions from oil and gas development and the extent to which those efforts could inform federal actions, we analyzed current and proposed regulations of a nongeneralizable sample of seven states—California, Colorado, New Mexico, North Dakota, Pennsylvania, Texas, and Wyoming—on methane

emissions from oil and gas development. We identified states by independently researching which states directly regulated methane or indirectly regulated methane by regulating volatile organic compounds (VOCs). As part of our background work, we also reviewed publicly available regulations on state websites and asked a group of federal and state agency officials, academics, and other stakeholders who are knowledgeable about methane regulation for recommendations of states we should include in our selection. We also reviewed total oil and gas production by state for 2019 (the latest available at the time of selection) from the Energy Information Administration to confirm that the recommendations we received and the states we identified have high oil and gas production. From the list of high oil- and gas-producing states we identified, we selected seven states because they proposed or issued final regulations on methane or VOCs, or experienced a large amount of flaring. We conducted semistructured interviews with officials from relevant state agencies in the selected states to clarify and confirm information from the documentation we obtained.[5] In interviews with officials in selected states, we used a standard set of questions but also discussed specific state perspectives, as appropriate. Because this is a nongeneralizable sample, our findings are not generalizable to other states not included in our review but provide some information on state efforts to regulate methane from oil and gas development. We also reviewed gas capture plan requirements in the Bureau of Land Management's (BLM) prior and current regulations, the agency's regulations and guidance that address waste of mineral resources on federal lands, and the Mineral Leasing Act of 1920.[6]

We conducted this performance audit from January 2021 to April 2022 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that

[5]In some cases, responsibility for regulating methane in a state is shared between the state environmental department and the oil and gas commission or conservation office. Through our research, we identified the relevant state agencies to be those that regulated air emissions, which were most often the state environment departments. In some cases, we also interviewed a state's oil and gas commission when we determined from our independent research and from speaking with state environment officials that the oil and gas commission also had a role in regulating methane.

[6]81 Fed. Reg. 83008 (Nov. 18, 2016); 83 Fed. Reg. 49184 (Sept. 28, 2018); and 44 Fed. Reg. 76600 (Dec. 27, 1979). Mineral Leasing Act of 1920, Pub. L. No. 66-146, 41 Stat. 437 (1920) (codified as amended 30 U.S.C. §§ 181 et seq.).

the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

# Appendix II: Measurement of Methane Emissions

Broadly, there are two approaches used to measure emissions. One, the bottom-up approach, estimates overall methane emissions by combining counts of individual components (or activities) with emissions per component or activity (the emission factor). The second, or top-down approach, determines total emissions from multiple sites via measurements from aircraft, satellites, or weather stations. The primary federal source of information on methane emissions in the United States is the Environmental Protection Agency's (EPA) annual Inventory of U.S. Greenhouse Gas Emissions and Sinks, generally referred to as EPA's Inventory. The Inventory, most recently issued in April 2021, uses a bottom-up approach of emissions factors for specific parts and activities associated with oil and gas operations to calculate total average emissions nationwide.[1]

Over the years, several studies have produced estimates of methane emissions, but there is significant uncertainty regarding the various estimates in these studies. According to a Congressional Research Service report, differences in data acquisition and analysis have resulted in competing, and often conflicting, methane emission estimates.[2] A 2018 report by the National Academies analyzed both bottom-up and top-down estimates of methane from fossil fuels and found that methane estimates ranged from 8 to 20 teragrams (trillions of grams) per year.[3] The report noted that progress had been made in understanding methane emissions by using bottom-up and top-down approaches together, but that information gaps exist.

Similarly, another study published the same year found that EPA's Inventory likely underestimates methane emissions by roughly 60 percent because the Inventory's methods do not include emissions caused by super-emitters, or equipment malfunctions that occur at a small subset of

[1]Environmental Protection Agency, "Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2019" (April 2021). EPA has published the Inventory each year since the 1990s.

[2]Congressional Research Service, *Methane: An Introduction to Emission Sources and Reduction Strategies* (Washington, D.C.: Aug. 15, 2016).

[3]National Academies of Sciences, Engineering, and Medicine, *Improving Characterization of Anthropogenic Methane Emissions in the United States* (Washington, D.C.: The National Academies Press, 2018), https://doi.org/10.17226/24987. According to the National Academies report, several studies found that top-down methane emissions estimates exceeded bottom-up inventories.

sites.[4] This study estimated that 7.6 teragrams per year of methane were emitted from the production segment of the oil and gas industry, while EPA's Inventory estimated that 3.5 teragrams per year came from that segment. In addition, a 2021 study found that a gap exists between bottom-up and top-down approaches to measuring methane and concludes that a recurrent theme in the literature is that EPA's Inventory underestimates methane emissions.[5] Specifically, the study found that recent estimates were 1.5 to 2 times higher than EPA's estimates.

According to EPA officials, it is possible that the EPA's estimates do not include all methane emissions from abnormal events because of differences in the practices and technologies across oil and gas systems and the occurrence of episodic events. Officials told us that, for many equipment types and activities, EPA's emission estimates include the full range of conditions, including super-emitters. For other situations, where data are available, EPA calculates emissions estimates for abnormal events separately and includes them in its Inventory. According to EPA officials, the agency continues to work through its stakeholder process to review new data from the EPA's Greenhouse Gas Reporting Program and research studies to assess how emissions estimates can be improved.

[4]R.A. Alvarez et al., "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain," *Science*, vol. 361, no. 6398 (June 21, 2018): 186-188. https://doi.org/10.1126/science.aar7204.

[5]J.S. Rutherford et al., "Closing the Methane Gap in US Oil and Natural Gas Production Emissions Inventories," *Nature Communications* (2021). https://doi.org/10.1038/s41467-021-25017-4.

# Appendix III: Comments from the Environmental Protection Agency

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
WASHINGTON, D.C. 20460

March 22, 2022

OFFICE OF
AIR AND RADIATION

Mr. Alfredo Gomez
Director
Natural Resources and Environment
U.S. Government Accountability Office
Washington, D.C. 20548

Dear Mr. Gomez

Thank you for the opportunity to review and comment on the U.S. Government Accountability Office (GAO)'s draft report, "Federal Actions Needed to Address Methane Emissions from Oil and Gas Development" (GAO-22-104759). The purpose of this letter is to provide the U.S. Environmental Protection Agency's (EPA) response to the draft report's findings, conclusions, and recommendations. GAO has recommended that EPA provide greater flexibility to operators to use alternative technologies to detect methane emissions. EPA generally agrees with GAO's recommendations.

GAO reviewed federal regulations and interviewed agency officials, industry representatives, and stakeholders including environmental groups and academics to obtain a broad perspective of the science and policy of methane detection standards and technologies. Analyzing documentation on industry efforts and academic studies, state regulatory standards, and extensive interviews, GAO concluded that EPA has made efforts to work with stakeholders to incorporate new and emerging technologies in methane detection into the regulatory framework for the oil and natural gas industry. GAO also noted the willingness and the movement of producers in oil and gas to use new technology to enhance efficiency and reduce emissions of methane.

**GAO Recommendation**

The EPA Administrator should provide greater flexibility to operators for using alternative technologies to detect methane emissions.

**EPA Response**

EPA generally agrees with the recommendation to provide greater flexibility to operators to incorporate new technology into methane detection programs. As GAO summarizes in its report, EPA's November 15, 2021, proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" would provide increased flexibility for the use of alternative technologies to detect methane emissions (86 FR 63110). EPA proposed an alternative screening approach that would allow operators to use advanced methane detection technologies to more frequently screen

sites for large emissions, followed by targeted ground-based optical gas imaging (OGI) surveys at those sites. See Section XI.A.5 of EPA's proposed rule preamble, section titled "Alternative Screening Using Advanced Measurement Technologies" (86 FR 63175). In that section, EPA further proposed that any advanced methane detection technology that has a minimum detection limit of 10 kg/hr could be used for screening on a bimonthly basis, in addition to an annual OGI survey. While the proposal was aimed at periodic screening technologies, EPA also solicited comment on how to incorporate the use of continuous monitoring systems. EPA also asked for 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.

EPA is planning a supplemental notice of proposed rulemaking for the Oil and Natural Gas source category that may further address requests for additional flexibility to the performance criteria and screening frequencies required when operators utilize the proposed alternative screening program. EPA is actively working, within the parameters of the Clean Air Act, to increase flexibilities for the use of alternative technologies to detect methane emissions via rulemaking, as opposed to augmenting our current process for alternative means of emission limitation requests.

In summary, EPA generally agrees with the recommendation to provide flexibility to oil and natural gas operators to incorporate new technology into methane detection programs. EPA is working to incorporate appropriate flexibilities into regulations for the Oil and Natural Gas source category through ongoing rulemaking.

I appreciate the opportunity to be of service and trust the information provided is helpful. If you have further questions, please contact Steve Fruh at (919) 541-2837 or *fruh.steve@epa.gov*.

Sincerely,

Joseph Goffman
Principal Deputy Assistant Administrator

cc: EPA GAO Liaison Team
Peter Tsirigotis
Christopher Grundler
Mike Koerber
Betsy Shaw
Eunjee Koh
Marc Vincent
Tiffany Purifoy
Daniel Hopkins
Sue Perkins
Amir Ingram

# Appendix IV: GAO Contact and Staff Acknowledgments

## GAO Contact

Frank Rusco, (202) 512-3841 or ruscof@gao.gov

## Staff Acknowledgments

In addition to the contact named above, Christine Kehr (Assistant Director), Marie Bancroft (Analyst-in-Charge), Matt Barranca, Nirmal Chaudhary, Maggie Childs, William Gerard, Cindy Gilbert, Yvonne Jones, Gwen Kirby, Danielle Novak, Archie Scoville, Dan Royer, Sara Vermillion, and Lauren Wice made key contributions to this report.