U.S. OIL & GAS METHANE POLICY

An Investor Guide

Environmental Defense Fund

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EXECUTIVE SUMMARY

The world has taken note of the power of cutting methane emissions from the oil and gas industry. Methane is a major source of global warming, with over 80 times the potency of carbon dioxide over 20 years. According to the IPCC, human-related methane emissions have caused one-third of the observed global warming to date.

The oil and gas industry is a leading contributor of methane emissions, and reducing them within the sector has emerged as the quickest, simplest and most affordable way to slow warming now. According to the International Energy Agency (IEA), reducing methane emissions from fossil fuels by 75% by 2030 would require less than 5% of industry's 2023 income. Some solutions even lead to a net profit for producers and growth opportunities for the rapidly expanding methane mitigation service industry.

A host of stakeholders is responding to methane's risks and opportunities.

Many oil and gas companies, recognizing the threat unabated methane poses to their future, have made public pledges to reduce their methane emissions and are participating in voluntary initiatives that promote emission accounting and reporting, like the Oil and Gas Methane Partnership 2.0.

The financial industry, too, is engaging on methane. Methane management is increasingly being factored into the valuation of oil and gas assets, and coalitions of investors representing more than $6 trillion in combined assets have called on oil and gas companies to take deliberate and concrete action on methane emissions.

Despite this progress, only a small fraction of the industry has taken meaningful action on methane, and regulators are filling the void globally.

As countries around the world strengthen their regulations, access to key gas markets in Europe, Japan and South Korea will hinge on imports having low methane emissions intensity. Regulations designed to reduce emissions across the entire industry in a cost-effective way are essential to bolster the competitiveness and reputation of U.S. producers, facilitate market access, and mitigate investment risk.

This guide provides an overview of the methane regulatory landscape (Appendix A) and examines a suite of new and revised rules that address oil and gas methane emissions and waste in the United States:

- U.S. Environmental Protection Agency Methane Standards
- U.S. Environmental Protection Agency Methane Emissions Reduction Program (MERP) (Subpart W and Waste Emissions Charge)
- Bureau of Land Management Waste Prevention Rule
- Pipeline and Hazardous Material Safety Administration Leak Detection and Repair Rule

The world has taken note of the power of cutting methane emissions from the oil and gas industry.

As countries around the world strengthen their regulations, access to key gas markets in Europe, Japan and South Korea will hinge on imports having low methane emissions intensity.

Based on extensive feedback from industry and other stakeholders, these rules present a comprehensive, harmonized approach to reducing methane from this oil and gas sector. For each rule, our team outlines the dates (Appendix B), requirements and context investors need to know to better engage their portfolio companies on these critical rules:

- Which types of companies does the regulation apply to?
- What is the effective date and compliance timeline?
- What are the requirements for leak detection and repair (LDAR), routine flaring and pneumatic devices?
- How does the regulation address super-emitters?
- What are the costs and benefits?
- How does the regulation interact with other federal regulations?
- Other questions relevant to each rule.

Opportunity for Investor Engagement

Because these regulations will play a critical role in mitigating financial, reputational, and other climate-related risks, to ensure their success, investors should engage with their portfolio companies to better understand their exposure to these regulations and how they plan to comply. To maintain this momentum on methane and send a strong signal to policymakers and global markets that U.S. producers can remain competitive in the energy transition, investors should also publicly support these regulations and urge their portfolio companies to do the same.

Research shows that companies with lower emissions have better financial performance.

Investors can leverage their unique platform and influence with companies and policymakers to support strong climate policies that will help level the playing field and facilitate long-term planning. Research shows that companies with lower emissions have better financial performance. In the oil and gas industry, operational excellence, efficiency, and minimization of waste often go hand-in-hand with lower methane emissions and flaring.

At the same time, some studies have found links between environmental and financial performance. Because of this, advocating in favor of policies to reduce emissions is necessary for investors to fulfil their fiduciary duty and minimize risk.

EDF policy experts stand ready to help the investor community better understand the international climate regulation landscape and find their voice on climate issues. The goal of this guide is to give investors the tools they need to engage with their portfolio companies and urge them to publicly support and quickly implement these rules.

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EXAMINATION: KEY U.S. METHANE REGULATIONS

EPA METHANE STANDARDS

EPA published its highly anticipated oil and gas methane standards in March 2024 after a robust stakeholder process which resulted in historic support from oil and gas companies and investors.

These standards will reduce emissions from new and existing oil and gas facilities by increasing the scope and frequency of leak detection and repair (LDAR), giving companies flexibility to use low-cost advanced monitoring technologies, phasing out routine flaring and certain polluting equipment (process controllers and pumps), and establishing a Super-Emitter Program (SEP) that will use emissions data reported by third parties to find and fix large methane leaks.

Which types of companies does the regulation apply to?

The EPA Methane Standards apply to owners and operators of new (New Source Performance Standards OOOOb) and existing (Emissions Guidelines OOOOc) onshore oil and gas facilities involved in production and processing (including equipment at well sites, centralized tank batteries, gathering and boosting stations, and gas processing plants) and natural gas transmission and storage (including transmission compressor stations and storage).

What is the effective date and compliance timeline?

The effective dates and compliance timelines are different for new and existing sources. For new sources (which EPA defines as those constructed, modified, or reconstructed after December 6, 2022), the effective date for most of the requirements is May 7, 2024. However, the regulation allows operators an additional year to transition to zero-emitting process controllers and pumps, and two years to phase out routine flaring.

For existing sources (constructed on or before December 6, 2022), requirements will begin after states have submitted and EPA has approved state plans. EPA will issue a federal implementation plan for states and Tribes that choose not to develop their own implementation plans.

This means that these standards will not apply to the more than 790,000 existing wells across the United States, and the emissions reductions and health benefits for the 9 million Americans that live in proximity to these sites are contingent on the adoption of these plans. Ongoing company and investor engagement in the implementation process will be essential to ensure the benefits of EPA's protections are fully realized.

What are the requirements for leak detection and repair (LDAR)?

Leaks and emissions from equipment failures are the largest source of methane pollution from oil and gas operations.EPA's standards ensure operators regularly inspect all sites and timely repair leaking equipment, deeply reducing methane while providing flexibility to use advanced monitoring approaches.

Operators may choose between a standard monitoring approach with handheld optical gas imaging (OGI or infrared) cameras and visual inspections, or an alternative based on advanced technologies like aerial flyovers, drones and continuous monitors. Any approach requires frequent and ongoing inspections at all sites, including low-producing and inactive wells, and all are projected to lead to significant cuts in pollution.

Under the standard monitoring approach, operators will have to inspect larger sites and those with failure-prone equipment four times per year using handheld gas-imaging cameras. Smaller sites less prone to leaks must be visually inspected four times per year. To help prevent orphan wells, wells must be monitored until they are properly closed and plugged.

Operators who choose to use advanced technologies will have to survey their sites between four and 12 times per year, depending on the sensitivity of the technology. Continuous monitors can be used, too, with follow up action required when elevated emissions are detected.

All technologies must be reviewed and approved by EPA before they can be deployed in the field — a process that stakeholders should continue to track. Incorporating operator feedback, EPA's Methane Standards also provide flexibility to use a suite of approaches at the greatest frequency associated with those various approaches.

What are the requirements for routine flaring?

Routine flaring is the burning of excess gas associated with oil production. Because flares often malfunction or are unlit, they can release methane and VOCs directly into the air.

EPA has significantly strengthened its standard for flaring, in line with, although not quite as strong as, leading states like New Mexico and Colorado, which have similar regulatory frameworks.

For new sources, EPA's Methane Standards phase out routine flaring of associated gas from newly constructed wells that are developed after the effective date of the rule. Options to avoid routine flaring include routing the gas to a sales line, using the gas as an onsite fuel source, using the gas for another purpose, or reinjecting the gas into a well. For existing wells producing more than 40 tons per year of methane, EPA requires operators to implement one of the same four options as required for new sources. If the operator demonstrates to EPA that such options are technically infeasible, the gas can be routed to a flare or other control device that achieves at least a 95 percent reduction in methane and VOC emissions. Demonstrating technical infeasibility includes conducting an evaluation of different technologies, an explanation of why each is not possible for the well, and certification by a professional engineer or other qualified person.

What are the requirements for pneumatic devices (i.e., process controllers and pumps)?

Process controllers and pumps are widely used to operate valves to control liquid level, pressure, and other variables. Collectively, they are the second largest source of emissions in the oil and gas supply chain.

EPA's final rule requires all new and existing process controllers and pumps to emit zero methane and VOC emissions. Zero-emission options include running controllers on electricity or solar-power or using compressed air.

In recent years, operators like EQT, the nation's largest gas producer, have successfully transitioned to zero-emitting controllers, noting that this is a cost-effective solution to reduce methane emissions.

How does the regulation address super-emitters?

Super-emitters play an oversized role in the total emissions from oil and gas sites. These harmful events are often related to abnormal processes — appearing when sites are not properly operated or designed – and are one of the reasons the sector's emissions have been significantly underestimated.

EPA has created and will oversee a new Super-Emitter Program, which will allow independent third parties to report large release events (super emitter events) using approved remote sensing technology such as aircraft or satellites. A super-emitter event is defined as any source of methane emissions exceeding 100kg/h at an individual well site, centralized production facility, natural gas processing plant, or compressor station.

EPA already regularly uses methane monitoring data from third parties, but this streamlined program will make that process more transparent and actionable for operators. EPA will review emission notifications and share them with operators who can investigate and quickly fix the underlying cause. To ensure the program is effective, third parties will need to receive a certification from EPA, and emission notifications will have to contain the time, location, emission rate and other information.

All notifications will be posted in real time after EPA review, providing transparency to the public and investors as well as accountability for the industry.

What are the costs and benefits?

According to EPA, industry-wide compliance costs are estimated to be $1.6 billion per year. Total capital costs are expected to represent just 1.6% of industry capital expenditures and 0.8% of industry revenue without revenues from product recovery or about 0.5 percent with revenues from product recovery.

EDF estimates that this would amount to $0.34 per BOE.

Once fully implemented, EPA's Methane Standards will eliminate 58 million tons of methane emission over the next 15 years – approximately the climate-equivalent of all the carbon dioxide emitted by the power sector in 2021. This is an 80 percent reduction of methane emissions expected without the rule.

EPA estimates that these standards will yield total monetized net benefits of nearly $100 billion over the next 15 years, or $7.3 to $7.6 billion a year, after taking into account the costs of compliance and savings from recovered natural gas. The rule will result in increased recovery of natural gas, valued at $7.4 to $13 billion from 2024-2038, or $820 to $980 million a year.iii

How does the regulation interact with other federal regulations?

EPA's Methane Standards work hand in hand with the Methane Emissions Reduction Program (MERP) (discussed below), and there will be no duplicative requirements on companies. Under MERP, a company will not pay the Waste Emissions Charge for pollution it eliminates, whether that reduction results from complying with voluntary efforts, state, local, or federal regulations, such as EPA's Methane Standards. In addition, facilities in compliance with EPA's Methane Standards once implementation plans are in effect in all states will not pay the charge. Lastly, facilities subject to EPA's Methane Rule will report those emissions through Subpart W of the Greenhouse Gas Reporting Program.

METHANE EMISSION REDUCTION PROGRAM

As directed by Congress in the Inflation Reduction Act, EPA officially published final updates to methane reporting requirements for the oil and gas sector under Subpart W of the Greenhouse Gas Reporting Program.

These updates will ensure that emissions reported to EPA more accurately reflect total emissions and are based on empirical data (i.e. data that are collected by observation and experiment), replacing outdated methods which have significantly underestimated the industry's emissions. They will also ensure that the upcoming Waste Emissions Charge is accurately and fairly assessed.

Paired with new satellite data, this rule will help investors benchmark companies more effectively and help them better understand their exposure to methane-related risk across the entire industry. It will improve the quality of emissions data reported from oil and natural gas operations, with provisions that improve the quantification of methane emissions, incorporate advances in methane emissions measurement technology, and work in tandem with EPA's Methane Standards.

Which types of companies does the regulation apply to?

Subpart W applies to owners or operators of onshore and offshore oil and natural gas facilities that emit at least 25,000 metric tons of CO2e (i.e. 1,000 tons of methane using a global warming potential of 25) annually involved in production and processing (including equipment at well sites, centralized tank batteries, gathering and boosting stations, and gas processing plants) and natural gas transmission and storage (including transmission compressor stations, underground storage, liquified natural gas (LNG) storage, LNG Import-Export Equipment, and Natural Gas Transmission Pipelines) and natural gas distribution systems.

What is the effective date and compliance timeline?

Most of the updates to Subpart W will become effective January 1, 2025, with submissions for the 2025 reporting year due March 31, 2026. An operator's Waste Emissions Charge for 2025 emissions will be assessed based on these updated reporting requirements.

However, facilities can start using these updated calculation methods to quantify their 2024 emissions if they so choose. This gives companies additional options to use empirical data to demonstrate the extent to which the Waste Emission Charge is owed for the first year. These optional calculation methods are effective July 15, 2024.

What are the requirements for leak detection and repair (LDAR), routine flaring, and pneumatic devices?

Unlike EPA's Methane Standards, Subpart W is a reporting rule, so it does not contain specific requirements for LDAR, flaring, or pneumatic devices. However, it does contain new calculation methodologies that allow for direct measurement of equipment leaks and pneumatic devices, where direct measurement options were not previously allowed, including equipment leaks and pneumatic devices. It also incorporates direct measurement approaches to help companies calculate flare efficiency.

For sake of comparison, Subpart W's updated reporting requirements align well with OGMP 2.0 guidelines. Through Subpart W's direct measurement requirements are generally more stringent than OGMP 2.0 guidelines, each OGMP 2.0 emission source category has at least one corresponding Subpart W emission source category. Therefore, a Subpart W-compliant measurement program will not only improve EPA's emissions inventories, but it will also provide an excellent starting point to a robust OGMP 2.0 implementation strategy.

How does the regulation address super-emitters?

The final Subpart W rule includes a new category for "other large release events," which captures abnormal emission events that were not accurately accounted for in the previous version of Subpart W. The regulation streamlines this source category by finalizing a single threshold of 100 kg/hr methane and specifying that the only third-party information required to be considered under other large release events are the notifications sent by the EPA through the Super-Emitter Program. With the addition of the other large release events category, for the first time in the Greenhouse Gas Reporting Program, EPA is giving operators the option to use advanced technologies (e.g., aircraft or satellite measurement) to help identify, quantify and report large release events.

What are the costs and benefits?

According to EPA, industry-wide compliance costs are estimated to be $183.6 million per year. The estimated cost per reporter is $55,100 per year.

EDF estimates that industry-wide compliance costs would amount to 0.12% of industry capital expenditures, 0.051% of industry revenue, and $0.041 per BOE. The costs* per reporter are miniscule.

Because this is a reporting rule that does not include any new emission control requirements, the EPA did not quantify estimated emission reductions or monetize the benefits from any reductions that could be associated with Subpart W. However, the benefits of this regulation are based on their relevance to policymaking, transparency, and market efficiency.

These updates will benefit policymakers, investors, and the public by increasing the completeness and accuracy of facility emissions data. They are also critical to the effectiveness of the Waste Emissions Charge. Crucially, these updates will also give companies a better understanding of where their emissions are coming from, which will enable them to better mitigate emissions.

*EDF estimates based on data from IEA, US Census Bureau and S&P Capital IQ

How does the regulation interact with other federal regulations?

The final Subpart W rule allows facilities to use a consistent method to demonstrate compliance with EPA's Final Methane Standards. It will ensure that the upcoming Waste Emissions Charge is accurately and fairly assessed.

WASTE EMISSIONS CHARGE

As directed by Congress in the Inflation Reduction Act, EPA published a proposal to impose and collect an annual charge on methane emissions that exceed specified waste emissions thresholds from applicable oil and gas facilities. The Waste Emissions Charge starts at $900 per metric ton for 2024 reported methane emissions, increasing to $1,200 per metric ton for 2025 emissions, and $1,500 per metric ton for emissions years 2026 and later. EPA's proposal would implement calculation procedures, flexibilities, and exemptions related to the Waste Emissions Charge. The public comment period closed in March 2024, and EPA is working to finalize the regulation later this year.

Which types of companies does the regulation apply to?

The Waste Emissions Charge applies to owners or operators of onshore and offshore oil and natural gas facilities that emit at least 25,000 tons of CO_2e annually and that are involved in production and processing (including equipment at well sites, centralized tank batteries, gathering and boosting stations, and gas processing plants) and natural gas transmission and storage (including transmission compressor stations, underground storage, liquified natural gas (LNG) storage, LNG Import-Export Equipment, and Natural Gas Transmission Pipelines.)

Because of the 25,000 ton threshold, the Waste Emissions Charge only impacts large polluting facilities. It likewise will only be assessed on companies with excessive emissions, meaning emissions above industry-aligned intensity thresholds.

What is the effective date and compliance timeline?

The Waste Emissions Charge will become effective on January 1, 2025.

What are the requirements for leak detection and repair (LDAR), routine flaring, pneumatic devices, and super-emitters?

Unlike EPA's Methane Standards, this rule outlines calculation methodologies, so it does not contain specific requirements for LDAR, flaring, pneumatic devices, or super-emitters. However, emissions from these equipment or processes would count toward a facility's total emissions for purposes of calculating its Waste Emissions Charge.

What are the costs and benefits?

Between 2024-2035, EPA estimates the Waste Emissions Charge will result in:

- $2.5 billion in payments to the U.S. Department of Treasury's general fund (with the largest payments occurring in years 2024-2026, prior to the availability of regulatory compliance exemption discussed below)
- a maximum 0.05% increase in the price of gas; and
- a maximum 0.04% increase in the price of oil.

EDF estimates that these payments would account for just 0.02% of industry revenue and 0.1% of industry CapEx.

EPA estimates this regulation will result in cumulative emissions reductions of 960,000 metric tons of methane and $1.6 billion in net benefits from 2024-2035 (in addition to the $2.5 billion in waste emissions charge payments).

How will the Waste Emissions Charge be calculated and assessed?

The Waste Emissions Charge would be assessed on methane emissions reported to EPA by the largest oil and gas polluters (approximately 15% of companies, according to EPA). It would apply to each excess ton of methane an operator emits above threshold levels that are based on industry supported targets for controlling pollution (i.e. methane intensities of 0.2% for production, 0.05% for gathering, boosting, processing, and storage, and 0.11% for transmission.) Facilities that meet or beat these thresholds would not pay the charge. See Appendix C - MERP Waste Emissions Charge Thresholds by Industry Segment.

As noted by the CEO-led Oil and Gas Climate Initiative (OGCI), collective methane intensity from member companies, such as bp, Chevron, and ExxonMobil, are supposedly already well below these thresholds. Similarly, non OGCI member companies, including but not limited to Devon Energy, EQT and PureWest Energy, have signalled their emissions already fall below these thresholds.

Operators subject to Subpart W of the Greenhouse Gas Reporting Program will be required to submit a Waste Emissions Charge filing and payment on March 31 of each year for the prior calendar year's emissions. The first payments will be collected March 31, 2025 for operators' 2024 emissions.

What is "netting" and how does it work?

As required by Congress in the IRA, EPA has proposed an approach for allowing the netting of emissions across different facilities owned by the same owner or operator. In other words, an operator can offset emissions from a lower performing facility if it has higher performing facilities below the thresholds. Positive net emissions are would be multiplied by the annual $/metric-ton value to calculate the total charge owed. If net emissions are zero or negative, no charge would be owed.

What are the exemptions to the Waste Emissions Charge?

There are several exemptions available to allow companies to avoid paying the charge:

Regulatory Compliance – Facilities would not pay a charge if they are in compliance with EPA's Methane Standards once implementation plans that meet or exceed EPA's standards are in effect in all states. Because this will be dictated by the implementation of individual state plans, states should move quickly to adopt and submit plans to EPA.

Permitting Delays – An operator would be able to seek an exemption from the charge if there is an unreasonable delay in permitting (32-40 months from when the permit was first submitted) which the operator is not responsible for.

Plugged Wells – EPA proposes to exempt emissions from plugged wells from an operator's overall charge obligation only when the relevant wells have been sealed to prevent any future leakage and when the operator has submitted documentation showing the well was plugged in accordance with all federal, state, and local requirements.

How does the regulation interact with other federal regulations?

Congress designed the Waste Emissions Charge to work in tandem with several related EPA programs. Operators will pay the Waste Emissions Charge based on their methane emissions reported to EPA under Subpart W of the Greenhouse Gas Reporting Program. The Waste Emissions Charge provides an incentive for the early adoption of methane emission reduction practices and technologies such as those required in EPA's Methane Standards.

Companies would be exempt from having to pay the Waste Emissions Charge if they are in compliance with EPA's Methane Standards once implementation plans are in effect in all states. The sooner facilities adopt the practices and technologies required in EPA's Methane Standards, the lower their assessed Waste Emissions Charge will be. As a result, the Waste Emissions Charge complements and reinforces EPA's Methane Standards and there will be no duplicative requirements on companies.

BLM WASTE PREVENTION RULE

BLM published its long-awaited rule to curb oil and gas waste on federal and Tribal lands in April 2024. According to BLM, the volume of natural gas vented and flared on public land has doubled since the 1980s. Between 2010 and 2020, an average of 44.2 billion cubic feet of natural gas was lost per year on federal and Native American leases, enough to support more than 675,000 homes. BLM's final rule includes new, phased-in requirements for oil and gas producers to take commonsense and cost-effective measures to reduce natural gas waste, develop LDAR plans, and pay royalties on certain natural gas losses. BLM officials will be able to delay or deny drilling permits if operators are not complying with these standards.

Which types of companies does the regulation apply to?

This rule applies to new and existing oil and gas facilities on federal and Tribal leases.

What is the effective date and compliance timeline?

BLM's rule becomes effective on June 10, 2024; some provisions will be phased in to give operators time to adjust. Flare measurements will be required either six, 12 or 18 months after the effective date of the rule, depending on their flow rate. Companies will have 18 months to submit leak detection and repair plans to BLM state offices.

What are the requirements for LDAR?

Operators must maintain an LDAR program designed to prevent wasted gas. The LDAR program must include regular inspections of all oil and gas production, processing, treatment, storage, and measurement equipment on the lease site and the final rule includes requirements for repairs when leaks are detected.

EPA's and BLM's LDAR frequencies for different wellsite types are largely overlapping. Both agencies allow the use of advanced technologies for detection.

What are the requirements for routine flaring?

IIn addition to climate and air quality impacts, states, Tribes, and federal taxpayers lose royalty revenues when gas is flared from oil and gas operations.

To ensure mineral owners and taxpayers are compensated, operators must take reasonable measures to prevent waste. This requires operators to either self-certify their commitment to capture (for sale or other productive use) 100% of gas produced or develop waste minimization plans before drilling. In either case, operators will pay royalties for gas that is wasted.

What are the requirements for process controllers and pumps?

The agency's final rule does not include any requirements for this equipment and instead defers to the zero-emission standard in EPA's Methane Standards.

What are the costs and benefits?

BLM estimates that the industry-wide cost of implementing requirements under the Waste Prevention Rule will be $19.3 million per year, and individual, small business operators may only see profit margins reduced, on average, by less than .2%.

EDF estimates this would amount to 0.01% of industry capital expenditures, 0.005% of industry revenue, and $0.041 per BOE.

BLM estimates that Waste Prevention Rule implementation will result in $1.8 million per year in benefits to industry in recovered gas and additional royalty revenues of $51 million per year to the American public and Tribal mineral owners. BLM estimates that 9,500 tons of methane emissions will be avoided per year as an ancillary benefit of reducing waste, corresponding to $18 million per year in avoided climate costs.

How does the regulation interact with other federal regulations?

Operators on federal or Tribal lands will need to comply with both BLM and EPA rules. EPA's Methane Rule is distinct from the BLM's Waste Prevention Rule. Whereas EPA's rule fulfils its mandate under the Clean Air Act to regulate harmful air pollution by requiring operators to achieve certain emissions reductions limits and use updated technologies, BLM's rule fulfils its mandate under the Mineral Leasing Act, which requires operators to take reasonable precautions to prevent waste and pay royalties on certain releases. BLM's rule does not distinguish between new and existing sources, and its effective date is earlier than EPA's.

PHMSA PIPELINE SAFETY, LEAK DETECTION AND REPAIR RULE

A part of the U.S. Department of Transportation, the Pipeline & Hazardous Materials Safety Administration (PHMSA) published a proposal to modernize its decades-old pipeline safety, leak detection and repair rules in May 2023. As directed by the bipartisan PIPES Act of 2020, the rule would enhance public safety and reduce methane emissions from covered facilities by as much as 55% by increasing the scope and frequency of leak surveys and requiring fast repair times. It would also require operators to develop Advanced Leak Detection Programs and consider using various commercially available, advanced leak detection technologies, which leading companies like Williams, Pacific Gas & Electric, National Grid, and Con Edison are already using.

Which types of companies does the regulation apply to?

This proposed rule applies to owners and operators of natural gas transmission and distribution pipeline systems, natural gas storage facilities, and a subset of upstream gas gathering pipelines. The proposed rule also applies to owners and operators of hydrogen pipelines and other gas pipelines.

What is the effective date and compliance timeline?

PHMSA has proposed that this rule would become effective six months after it is officially published in the Federal Register.

What are the requirements for leak detection and repair (LDAR)?

For distribution pipeline systems, all pipelines would need to be surveyed at least once every three years and pipelines in business districts or that may be at risk of corrosion or leakage due to their material type must be surveyed annually. All transmission and some gathering pipelines would need to be surveyed one to four times per year, depending on their classification and proximity to populated areas.

Under existing standards, there is no clear timeline for leak repair, allowing operators to leave most leaks persisting on their system for years. The proposed standards would require operators to repair almost all leaks within two years and repair many leaks faster than that. Additionally, because advanced leak detection technologies like aerial or vehicle surveys are more effective than conventional methods at finding and measuring pipeline leaks, PHMSA's proposal requires operators to develop Advanced Leak Detection Programs.

What are the requirements for routine flaring?

The proposed rule does not contain specific requirements for flaring. The proposed rule would require operators to mitigate operational gas releases from pipelines, like venting and blowdowns, using a number of mitigation methods. One such approved method would allow operators to route gas from the pipeline to a flare or to other equipment as fuel gas.

How does the regulation address super-emitters?

The proposed rule would establish national standards for leak grading, which is how operators prioritize pipeline leaks for repair. Grade 1, which present an urgent or immediate emergency, must be repaired immediately. Grade 2 would include leaks posing "a significant hazard to the environment," with a leak rate of 10 cubic feet per hour or greater.

Under the proposal, operators would need to promptly report to PHMSA large volume releases exceeding 1 million cubic feet of natural gas.

What are the costs and benefits?

PHMSA estimates that the overall compliance costs to industry would be $740 million to $900 million per year, compared with $341 million to $1.4 billion in benefits per year (with additional unquantified benefits to public safety and the environment.)

EDF's estimates this would amount to 0.49% to 0.59% of industry capital expenditures, 0.05% to 0.06% of industry revenue, and $0.07 to 0.09 per BOE.

In addition to significant public safety and environmental benefits, PHMSA's proposal will reduce product loss, lead to cost savings for the industry and consumers, and improve the efficiency and reliability of U.S. energy infrastructure.

Cleaner pipeline infrastructure will reduce emissions across the value chain, which will help ensure that U.S. companies remain competitive in global markets and are more resilient in the energy transition.

How does the regulation interact with other federal regulations?

PHMSA's proposed standards for improving pipeline safety and methane pollution primarily apply at facilities that are not subject to EPA's Methane Standards, including local gas distribution pipeline systems, transmission and gathering pipelines, and certain components of LNG and underground gas storage facilities.

Where PHMSA standards have the potential to apply at facilities that would also be regulated under EPA's Methane Standards, PHMSA has largely proposed to streamline compliance. For example, PHMSA has proposed an exemption from its LDAR requirements for any transmission or gathering compressor station that is subject to the LDAR requirements in EPA's Methane Standards, or an EPA-approved state implementation plan which includes relevant standards at least as protective as EPA's Methane Standards. If EPA's Methane Standards are not in effect, then PHMSA's LDAR standards would apply to those compressor stations as a backstop.

APPENDIX A: US METHANE REGULATORY LANDSCAPE AND GLOBAL CONTEXT

Federal, state, Tribal, and local governments each regulate various aspects of oil and gas operations. Who regulates what depends on land ownership and whether federal regulations or state laws apply.

U.S. Environmental Protection Agency (EPA)

EPA oversees a range of regulations designed to protect public health and the environment, including emissions performance standards and greenhouse gas reporting for certain oil and gas infrastructure, primarily through the Clean Air Act. EPA regulates new sources of pollution directly through New Source Performance Standards and works collaboratively with states to regulate existing sources through Emissions Guidelines.

EPA has established New Source Performance Standards for the oil and gas sector, which set emission limits for various sources to reduce methane emissions during the production, processing, transmission, and storage of oil and natural gas. New Source Performance Standards are prescriptive and set specific emission limits or standards that new or modified sources must meet. These standards are technology-based and often require the use of specific pollution control technologies or work practices.

EPA has established Emission Guidelines to provide guidance to states for developing state plans to control emissions from existing sources. Emissions Guidelines establish emission reduction goals and recommend control measures that states should adopt to achieve those goals and provide states flexibility in developing their own regulations to control emissions from existing sources.

Though state plans must be reviewed and approved by EPA, states have the authority to choose the regulatory mechanisms and control measures that best suit their circumstances, as long as they achieve the emission reduction goals outlined in EPA's Emissions Guidelines. If a state declines to submit an approvable state plan, EPA will develop and implement a federal plan applying to existing sources in that state.

U.S. Bureau of Land Management

Within the U.S. Department of Interior, the Bureau of Land Management (BLM) has jurisdiction over leasing, exploration, development, and production of oil and gas on federal and Tribal lands, primarily through the Mineral Leasing Act and the Federal Land Policy and Management Act.

BLM has the express authority and responsibility to regulate for the prevention of waste and the protection of the environment for operations on Federal and Tribal lands. This responsibility includes promulgating regulations to reduce the waste of oil and gas from leases administered by the BLM. BLM rules and standards for drilling and production require all operations on federal land to comply with EPA, state and local regulations and protect life, property, and environmental quality.

Pipeline and Hazardous Materials Safety Administration

The U.S. Department of Transportation (DOT) manages the U.S. transportation system. Within DOT, the Pipeline & Hazardous Materials Safety Administration (PHMSA) is responsible for regulating and ensuring the safe and secure transport of energy and other hazardous materials to industry and consumers by all modes of transportation, including pipelines.

Natural gas is transported around the country in a network of approximately three million miles of pipelines, and leakage from this infrastructure is a major source of methane emissions. Research has found that these emissions are significantly underestimated and disproportionately impact disadvantaged communities.

PHMSA oversight of natural gas infrastructure has long focused on human safety, but the agency is directed by law to set minimum pipeline safety standards that protect both safety and the environment. Under the Biden Administration, PHMSA is working to fulfill this mandate. The "Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020" (PIPES Act of 2020), specifically addresses the minimization of releases of natural gas from pipeline facilities and requires PHMSA to establish standards for pipeline leak detection and repair.

State, Tribal, and Local Government

State, Tribal, and local governments play crucial roles in regulating oil and gas activities within their borders. Exploration and production on state, Tribal and private lands are regulated by each of the 33 oil- and gas-producing states and 12 Tribes.

Though the federal government sets overarching regulations, state, Tribal, and local agencies often have more specific and localized regulations to address environmental and public health concerns. With respect to methane emissions, while EPA sets national standards, states and Tribes often work in partnership with EPA to develop and enforce state and Tribal plans, which outline how they will achieve and maintain compliance with federal air quality standards. While all state and Tribal plans are required to be at least as protective as EPA standards, some states and Tribes may implement more stringent requirements.

Global Methane Regulatory Landscape

Outside of the United States, the global policy landscape is also zeroing in on methane emissions. Because these are key markets for energy produced in the United States, these requirements will have positive impacts on domestic uptake of domestic regulations.

E.U. Methane Regulation

On May 27, 2024, the European Council approved landmark methane regulation that covers emissions from domestic production and addresses emissions associated with imported oil, gas and coal. The regulation will enter into force 20 days after it is adopted by the European Council and published in the E.U. Official Journal.

Under the regulation, oil and gas operators must measure, monitor, report and verify their methane emissions and reduce them. They must detect and repair methane leaks, stop routine venting and flaring of methane, and reduce flaring and venting to situations such as emergencies, technical malfunctions, or where it is necessary for safety reasons. They also must establish mitigation plans for inactive or abandoned wells.

Because the E.U. imports more than 80% of its oil and gas, the regulation targets imports to drive global climate impacts. Specifically, it requires importers to match E.U. domestic measurement and reporting standards by 2027, and for imports to comply with certain methane intensity standards by 2030. Japan is considering similar import standards.

These stricter import standards underscore the critical need for strong regulations in the U.S. Without strong regulations to ensure a competitive baseline from a methane perspective, U.S. producers will find it more difficult to access global markets that are increasingly demanding better methane performance.

Similar to EPA's Super Emitter Program, the European Commission will also set up a rapid alert mechanism for super-emitting events so operators can take action to stop or prevent these events.

Canada Methane Regulation

Environment and Climate Change Canada (ECCC) proposed draft regulations in December 2023. This proposal is designed to reduce methane emissions from upstream, midstream, and transmission facilities in the onshore oil and gas sector by more than 75% by 2030 by eliminating routine venting and flaring, enhancing leak detection and repair, and addressing problems such as large release events. It is anticipated that ECCC will finalize these regulations by the end of 2024.

To support Canada's ambitious methane reduction plan, the Government of Canada announced a $30 million investment to establish a Methane Centre of Excellence in the near term that will improve understanding and reporting of methane emissions, with a focus on collaborative measurement and mitigation initiatives.

APPENDIX B: U.S. METHANE REGULATORY TIMELINE

	2021	2022	2023	2024	2025	2026	2027	2028	2029
EPA METHANE STANDARDS	**NOV. 15** Proposed	**NOV. 5** Suppl. Proposal	**MARCH 8** Finalized	**MAY 7** Effective Date State Impl. Plans Begin	**MAY 7** Zero-emitting Controllers and Pumps Required	**MAY 7** Phase Out Routine Flaring State Impl. Plans Due	EPA Acts on State Impl. Plans	**MID 2028** Federal Impl. Plans	Source Compliance Deadline
SUBPART W			**JULY 31** Proposed	**MAY 14** Finalized **JULY 15** Optional Effective Date	**JAN 2** Effective Date	**MARCH 31** Annual Reports Due			
WASTE CHARGE				**JAN. 28** Proposed **FALL-WINTER** Finalized	**JAN. 1** Effective Date **MARCH 31** First Charge Collection: $900/ton	**NEW CHARGE:** $1200/ton	**NEW CHARGE:** $1500/ton Eligibility for Reg. Compliance Exemption		
BLM WASTE RULE		**NOV. 30** Proposed		**APRIL 10** Finalized **JUNE 10** Effective Date	**DECEMBER** LDAR Plans Due				
PHMSA RULE			**MAY 5** Proposed	**SUMMER 2024-EARLY 2025** Finalized		Effective within 6 months			

APPENDIX C: WASTE EMISSION CHARGE THRESHOLD BY INDUSTRY SEGMENT

INDUSTRY SEGMENT	WASTE EMISSIONS CHARGE INTENSITY THRESHHOLD
Offshore Petroleum and Natural Gas Production Onshore Petroleum and Natural Gas Production	.2%
Natural Gas Processing Underground Natural Gas Storage Liquefied Natural Gas Storage Liquefied Natural Gas Import and Export Equipment Onshore Petroleum and Natural Gas Gathering and Boosting	.05%
Onshore Natural Gas Transmission Compression Onshore Natural Gas Transmission Pipeline	.11%

Environmental Defense Fund

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