August 3, 2022

Benefits of measurement-based methane estimates and timely emissions reductions for reaching the long-term global goal on temperature:

Submission to the Global Stocktake by the Environmental Defense Fund

Key messages:

- Readily available methods to reduce methane can deliver **0.25°C of avoided temperature rise by 2050**, significantly contributing to achieving the long-term temperature goal of the Paris Agreement.
- All Nationally Determined Commitments (NDCs) should cover methane. **NDCs should include methane-specific targets as well as policies and strategies to achieve those targets**, such as those included in Annex I (Mohlin et al 2022).
- Striving to improve national emissions inventories by comparinging them with newly available measurement-based methane data would allow **Parties to better target methane emissions sources and take credit for progress both individually and collectively**. The Intergovernmental Panel on Climate Change (IPCC) should develop **guidance on such practices for Parties to use on a voluntary basis**. The International Methane Emissions Observatory (IMEO) can support interested Parties in these practices.
- **Resources exist[1] to build capacity for countries to reduce methane emissions** particularly from the oil and gas sectors, and also from the waste and agriculture sectors.

Background:

The Global Stocktake (GST) is intended to assess collective progress toward the long-term goals of the Paris Agreement and inform Parties in enhancing their actions in a nationally determined manner. It is **an opportunity catalyze action within and beyond the UNFCCC on a range of mitigation solutions, including methane.** And, if done well, it could help countries implement their existing climate commitments and provide the impetus and information necessary for them to raise the ambition of their next NDCs.

[1] Climate and Clean Air Coalition, Global Methane Initiative, Global Methane Hub

In response to the Chairs of the Subsidiary Bodies' guiding question 5[2] for the Technical Assessment component of the GST, this submission **points to potential solutions that can help Parties reduce methane emissions**, increase the ambition of their NDCs, and support achievement of the global temperature goal. It also provides information and options on **how to better track progress on those actions via national emissions inventories**.

Further action required:

Current NDCs are not consistent with global emission levels that would limit warming to the goals defined in Articles 2.1(a) and 4.1 of the Paris Agreement. The IPCC WGIII (2022) found a gap of 6-14 $GtCO_2e$[3] in 2030 between conditional NDCs announced prior to COP26 and the emissions reductions in modeled pathways projected to result in holding temperature rise to 2℃, and likewise a gap of 16-23 $GtCO_2e$ to limit warming to 1.5℃.

Methane is a shorter-lived and far more powerful greenhouse gas than carbon dioxide. While cumulative carbon dioxide emissions define global temperature rise in the long term, methane emissions strongly affect the rate of warming, the peak temperature level, and the risk of a temperature overshoot. The IPCC WGIII (2022) found that **reductions of methane emissions would lower peak warming and reduce the likelihood of overshooting warming limits**. Early methane mitigation is also critical for reducing the risk of catastrophic events such as the near-complete loss of summer Arctic sea ice (Sun et al., 2022).

Because of methane's warming power and its short atmospheric lifetime, **reducing methane emissions also is the fastest way to slow the rate of global warming in the near term** (Ocko et al., 2021; Sun et al., 2021; UNEP and CCAC, 2021). Thus, while methane emission reductions are not a substitute for rapid and deep reductions in carbon dioxide emissions, they are also **a critical step toward reaching the temperature goal of the Paris Agreement.**

Opportunities, good practices, lessons learned and success stories:

The emissions gap described above includes readily available low- or even negative-cost emissions reductions. Timely implementation of existing methane mitigation measures could contribute to reaching these goals by slowing the rate of near-term warming by 30% and **avoiding 0.25 ºC of additional warming by midcentury** (Ocko et al., 2021). Parties should abate these emissions as quickly as possible. However according to the UNFCCC's 2021 NDC

[2] In order achieve the goals defined in Articles 2.1(a) and 4.1 of the Paris Agreement: a) What further action is required? b) What are the barriers and challenges, and how can they be addressed at national, regional and international levels? c) What are the opportunities, good practices, lessons learned and success stories?
[3] Using Global Warming Potential 100 (GWP100)

Synthesis Report[4] not all NDCs include methane. **All updated NDCs should include methane and methane-specific targets.**

Anthropogenic methane emissions are primarily associated with the oil and gas, waste and agricultural sectors. The oil and gas sector offers the largest share of low-cost reduction opportunities (UNEP 2021; IEA 2022). The IPCC WGIII (2022) found that **50-80% of oil and gas sector methane globally could be abated at less than \$50/tonCO_2e using existing technology**. Annex I to this submission, "Policy instrument options for addressing methane emissions from the oil and gas sector" details policy options that can serve as a resource for Parties to reduce methane emissions in the oil and gas sector. These include direct regulatory strategies like mandating regular leak detection and repair surveys, restrictions on venting and flaring, and equipment technology standards as well as policy instruments based on methane emission quantification and Monitoring Reporting and Verification. The latter options cover policy instruments both for oil and gas producing countries and oil and gas importing countries. **We strongly encourage Parties to consider these policy instruments as opportunities, good practices, lessons learned and success stories, and to include them in NDC targets**.

For Parties that have demonstrated a desire and commitment to methane action including by joining the Global Methane Pledge to reduce global methane emissions by 30% by 2030**, the Global Methane Hub, the Climate and Clean Air Coalition (CCAC) and the Global Methane Initiative (GMI) stand ready to support in designing and implementing policies** such as those in the paper as well as others in the waste and agriculture sectors.

Barriers and challenges, and how they can be addressed:

Efficient abatement depends on accurate characterization of emission sources. For a number of reasons**, existing inventory methodologies do not fully capture methane emissions,** particularly from the oil and gas supply chain. In some cases, initial assumptions without measurement-based data would point to the wrong methane sources to target for abatement (Zavala-Araiza et al., 2021).

The accuracy of national emissions inventory data can be improved by implementing the following practices:

1. Interested countries may establish the infrastructure and processes to collect as many multi-scale measurement-based emissions data as possible (i.e., flux estimates at country and regional scale based on inverse modelling of atmospheric observations). Recent studies have demonstrated how satellite remote sensing can be used to generate this type

[4] https://unfccc.int/documents/307628

of data (Jacob et al. 2022; Shen et al. 2022; Zhang et al., 2020). Previous work has also illustrated data collection based on tower-based sensors (Henne et al. 2016; Lin et al. 2021; Palmer et al. 2018).

2. With appropriate support, inventory compilers can engage with the inverse modelling and atmospheric observation communities to establish a comparison between estimates produced in #1 and the source by source, bottom-up inventory (Shen et al., 2021; Zavala-Araiza et al., 2021). Where the two estimates differ, this could be reflected in the uncertainty estimate of the national inventory.
3. Lastly bottom-up inventories can strive to reconcile with the estimates using measurement-based flux data in #2 above (Rutherford et al., 2021). This process would resolve discrepancies and improve the bottom-up inventory by crucially shedding light on sources that require further characterization and abatement (Alvarez et al., 2018).

The IPCC's 2019 Refinement to its greenhouse gas Inventory Guidelines (IPCC, 2019) states broadly that the data described in Step 1 above can inform bottom-up inventories. However, the 2019 Refinement does not provide step-by-step instructions or methodology for inventory compilers to put these tools into practice. The IPCC's Task Force on Inventories should work towards **providing step-by-step guidance to national greenhouse gas inventory compilers on how to carry out Steps 1 and 2** above. The International Methane Emissions Observatory (IMEO) can also work with interested countries on Steps 1 and 2, and could support them in the reconciliation process described in Step 3.

Recognizing countries that make the effort to better characterize uncertainty in their national inventory (i.e. Step 2) by adding a moniker, such as "Tier IV" would reward them and build support for the practice. This would be along the lines of the Oil and Gas Methane Partnership (OGMP) 2.0's Level 5[5] methodology for companies. Given that the Conference of the Meeting of Parties to the Paris Agreement (CMA) has adopted the 2006 IPCC Guidelines as the guidelines for Parties to use in developing their national GHG inventories[6] and that Parties may use the 2019 Refinement to the 2006 IPCC Guidelines on a voluntary basis[7], **such practice would necessarily be purely voluntary**.

These approaches will be enabled by satellite capabilities that are growing at an extraordinary rate. EDF's MethaneSAT is a leading example. To be launched in October 2022, MethaneSAT will provide unprecedented high-resolution, global coverage of methane emissions from oil and gas facilities[8]. Other efforts such as GOSAT-GW, Sentinel 5, and GeoCarb can contribute in the future as well (Jacob et al. 2022).

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[5] Mineral Methane Initiative OGMP2.0 Framework (2020) http://ogmpartnership.com/sites/default/files/files/OGMP_20_Reporting_Framework.pdf
[6] Decision 18/CMA.1, annex, para. 20, https://unfccc.int/sites/default/files/resource/cma2018_3_add2_new_advance.pdf#page=23
[7] Decision 5/CMA.3, para. 28, https://unfccc.int/sites/default/files/resource/cma2021_10a2_adv.pdf#page=5
[8] https://www.methanesat.org/

With more accurate inventories, Parties could track their mitigation actions more closely and take credit for their progress. And with such improved information the GST process can, in a virtuous cycle, more accurately assess collective progress and identify opportunities for action.

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Annex I:

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Policy instrument options for addressing methane emissions from the oil and gas sector

Kristina Mohlin, Maureen Lackner, Huong Nguyen, and Aaron Wolfe

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Policy instrument options for addressing methane emissions from the oil and gas sector

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Abstract

Policy makers around the world are increasingly recognizing the need to drastically reduce methane emissions in parallel with carbon dioxide emissions. More than a hundred countries have signed the Global Methane Pledge and made a collective commitment to reduce global methane emissions by 30% by 2030 from 2020 levels.

Methane emissions in the oil and gas sector are considered particularly promising, not only because of low or even negative net abatement costs for many emission sources, but also because most of these solutions involve mature existing technologies and work practices. Still, methane-reduction efforts in this sector have not yet been realized extensively due to a combination of informational, structural, financial, and regulatory barriers. This paper therefore lays out regulatory and policy instrument options available to strengthen the incentives to address methane emissions in jurisdictions that produce oil and gas as well as in those that import oil and gas.

The objective of this paper is to give policy makers, regulators, and other stakeholders a description of the main policy and regulatory levers available to realize the significant methane mitigation opportunities in the oil and gas sector. It aims to provide an overview of the different policy instrument options and thereby help policy makers assess which option is most attractive given regional circumstances and the relevant regulatory and political constraints.

Keywords

Climate policy, methane emissions, oil and gas sector, environmental policy instruments, environmental policy design.

JEL Classification Numbers

Q01, Q35, Q38, Q58

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1. Introduction

In order to keep global temperature change to well below 2 ºC, policy makers around the world are increasingly recognizing the need to drastically reduce methane emissions in parallel with carbon dioxide emissions. In connection with COP26 in Glasgow, more than a hundred countries signed up to the Global Methane Pledge and made a collective commitment to reduce global methane emissions by 30% by 2030 from 2020 levels.[1]

Many targeted measures exist to cut methane emissions from human activities (United Nations Environment Programme [UNEP], 2021). Timely implementation of the appropriate mitigation measures could slow the rate of near-term warming by 30% and avoid 0.25 ºC of additional warming by midcentury (Ocko et al., 2021). Mitigation options exist across the fossil fuel, agricultural, and waste sectors, with the oil and gas sector frequently singled out as offering the largest share of low-cost reduction opportunities (see, e.g., Ocko et al, 2021; UNEP, 2021; International Energy Agency [IEA], 2022a).

Methane emissions mitigation in the oil and gas sector is considered particularly promising, not only because of low or even negative estimated net abatement costs for many sources, but also because most of these solutions involve mature existing technologies and work practices (IEA, 2021a). Still, methane-reduction efforts in this sector have not yet been realized extensively due to informational, structural, financial, and regulatory barriers (see, e.g., United Nations Economic Commission for Europe [UNECE], 2019; IEA, 2021b).

The historic focus on operational production performance of oil and gas operators, combined with challenges to methane detection and quantifitation, has previously resulted in a lack of awareness regarding the industry's methane emissions and explained a general lack of attention to the problem. This has started to change with the development of new and affordable methane detection and measurement technologies and with new scientific studies demonstrating the extent of the industry's methane emissions problem.

In addition, the design of joint venture contracts and production-sharing agreements typically provide limited incentives for investment in the capture of gas associated with oil production, where gas is typically viewed as a by-product (UNECE, 2019). Furthermore, even in instances where captured methane can be sold on the market, the extent to which the expected costs and

[1] For more information see https://www.globalmethanepledge.org

benefits of abatement investments balance out depends on gas prices, which can be volatile and depressed locally due to limited gas take-away capacity (i.e., lack of transportation infrastructure). Hence, the volatility of gas prices and, in some places, low local gas values hinder methane capture efforts, especially in the oil and gas sector, which tends to prioritize investment projects with high expected rates of return.

Regulations in place in most jurisdictions also remain insufficient to incentivize comprehensive methane management and the associated changes needed in operations and investment in the oil and gas sector (IEA, 2021a). This paper therefore lays out some of the main regulatory and policy instrument options available to strengthen incentives to address methane emissions.

The objective of this paper is to give policy makers, regulators, and other stakeholders a description of the main policy and regulatory levers available to realize the significant methane mitigation opportunities in the oil and gas sector. The paper aims to provide an overview from an economics perspective of the different policy instrument options and thereby help policy makers assess which option is most attractive given regional circumstances and regulatory and political constraints.[2] For a complementary step-by-step guide to practical methane policy implementation, we refer readers to the IEA's (2021b) methane regulatory roadmap, which in addition to regulatory design and development also covers the first phase of understanding the local setting and circumstances, and the final phases of implementation and policy evaluation.

In general, different policy options are available for addressing methane emissions from the different segments of the oil and gas supply chain:

(1) Upstream domestic emissions in the form of venting, incomplete flaring, as well as fugitive emissions (i.e., leaks from oil and gas infrastructure) in oil- and gas-producing countries;

(2) "Imported" footprint emissions for oil- and gas-importing countries, where policy instruments target the same emissions as 1) but the instrument's point of obligation is on the importer or buyer side;

(3) Midstream emissions, primarily in the form of gas leaks from liquefied natural gas (LNG) facilities, gas transmission pipelines, and storage;

(4) Downstream emissions, primarily in the form of gas leaks from gas distribution systems.

[2] For a general introduction to how economists approach instrument choice in environmental policy, see, e.g., Goulder and Parry (2008) and Sterner and Coria (2011).

Many of the regulations implemented so far for addressing methane emissions from the oil and gas sector are prescriptive direct regulations, such as work practice standards for mandatory regular leak detection and repair (LDAR), restrictions on venting and flaring practices, and standards for equipment technology with low methane emissions. We provide an overview of these tried and tested regulatory options in Section 2.

The rest of this paper focuses on policy instrument options that are based on methane emissions quantification and thus methane monitoring, reporting, and verification (MRV).[3] These MRV-based policy options have so far been implemented in only a small number of cases that have relatively limited scope (see Section 4 for a detailed discussion). However, significant advances in methane measurement technologies and quantification methods have made robust MRV approaches possible, which in turn enable policy instruments based on emission quantification. We describe features of robust MRV systems and certification of low methane emissions in Section 3, before discussing policy instrument options based on MRV in Section 4.

In the context of the Global Methane Pledge, countries are considering both domestic methane emissions arising inside their own borders from the oil and gas supply chain, as well as their so-called footprint emissions — i.e., the methane emissions associated with their imports of oil and gas. Options for the regulation, monitoring and enforcement of footprint emissions for importing countries are more limited, whereas in the country where the emissions arise policy makers have a wider range of policy instrument options for addressing domestic emissions and the regulatory agency has better opportunities to monitor and enforcement them.[4] To recognize this distinction between domestic and footprint methane emissions in the upstream segment of the oil and gas supply chain, Section 4 discusses the policy instrument options available to oil- and gas-producing countries separately from the policy instrument options available to oil- and gas-importing countries.[5]

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[3] Here we are using methane MRV to refer to a methodology for quantification of methane emissions, not just detection of emissions. Sometimes the acronym MRV is used to abbreviate “measurement, reporting, and verification.” We are not making a distinction between those usages here and refer to the Oil and Gas Methane Partnership (OGMP) 2.0 framework for details on how to carry out robust measurement/monitoring and reporting of methane emissions (see UNEP, 2020).

[4] The regulatory capacity to monitor and enforce methane regulations will, however, vary across jurisdictions with the institutional capacity and amount of resources at the relevant agency’s disposal.

[5] These policy instrument options may also be available to an individual state, region, or province in a federal country. Henceforth, we use country to refer to jurisdiction throughout this paper, but the discussion and insights presented apply also at the subnational level for states or provinces, or to supranational regions with the relevant jurisdictional powers. A legal or regulatory discussion of which of the policy options are available in which jurisdictions is beyond the scope of this paper.

In Section 5, we discuss regulatory options for improving the incentives for gas transmission and distribution entities to manage methane leaks from mid- and downstream gas infrastructure.

In Section 6, we lay out outstanding questions for public policy researchers to analyze so that further guidance can be provided on the design and impacts of different policy instrument options for addressing methane emissions in the oil and gas sector. Section 7 concludes the paper.

2. Work practice and technology standards

To address methane emissions along the oil and gas supply chain, established work practice and technology standards have already been tried and tested in several jurisdictions, including at the U.S. federal level and the states of California, Colorado, and New Mexico, and in the Canadian provinces of Alberta and British Columbia. Economists often refer to direct regulatory approaches like these as "command and control" regulations because they mandate specific methodology or technology criteria that companies should use to reduce their emissions. These are in contrast to the policy instruments discussed in Section 4, which give companies more flexibility on how to comply with the associated regulation and reduce emissions.

In the methane emissions context, these regulatory options include mandated regular LDAR, restrictions on venting and flaring practices, and technology standards on oil and gas infrastructure equipment. These options are relevant to both the upstream oil and gas segments as well as the mid- and downstream segments of the gas supply chain.[6] To consider differing operational constraints, the details of work practice standards may need to be adjusted to the specific oil and gas segment targeted. For example, the upstream segment typically offers larger potential for emission reductions, motivating relatively more stringent requirements, while rapid repairs in the downstream segment may be more complicated in city gas grids, which are required to stay operational to provide a stable supply of gas to their end-use customers.

Because work practice and technology standards are not based on emission quantification, they have the advantage that they can be put in place before methane quantification methods have been established and implemented (see also IEA, 2021b). This feature also implies that these regulatory options do not entail direct tracking of emission levels, which would otherwise allow for assessment of progress made in reducing those levels over time. Compared to the policy instrument options based on methane MRV (discussed in Section 4), it is therefore more challenging to assess and evaluate whether these regulatory options lead to sufficiently large methane emissions reductions to meet stated policy targets. Nevertheless, compliance with these regulations can be monitored and estimation techniques used to chart progress over time. At present it is also not cost-effective or feasible to continuously monitor and quantify methane

[6] Methane emissions from the oil supply chain are mainly relevant in the upstream segment, where oil and gas are often coproduced. At the mid- and downstream stages of the oil supply chain, the commodity is in liquid form and separate from the gas supply chain, and methane emissions are therefore less relevant here.

emissions from all individual sources. Therefore, even in jurisdictions that implement MRV-based policy instruments, these prescriptive direct regulations are a necessary complement to such policies and provide a means to achieve a foundational level of emission reductions across all sources.

Another notable feature of these regulations is that, in addition to targeting methane, they often reduce local air pollution caused by oil and gas production. This includes health-harming pollutants such as volatile organic compounds (VOCs) and various hazardous air pollutants (HAPs) (Lattanzio, 2020). By limiting local exposure to these health hazards across all regulated sites, work practice standards can play a role in protecting communities living close to oil and gas production sites at the same time as they seek to address methane emissions.

To make work practice and technology standards effective in reducing emissions, it is essential for the relevant regulatory agency to have the resources and know-how to effectively monitor and enforce the regulations. Relevant considerations for effective enforcement include what data the operator is required to report to the regulatory agency, the capacity of the agency to verify those reports and the level of the fines issued for misreporting and non-compliance. This naturally also applies to the other policy instruments covered in this paper. Capacity-building and sufficient resources— particularly in developing countries but also in developed countries — that gives agency staff the necessary knowledge and tools to understand methane emissions and their sources is needed to make sure that once regulations are implemented they can also be effectively monitored and enforced. The IEA's (2021b) regulatory roadmap provides more details and a guide to the steps and resources necessary to move from methane policy implementation and enforcement to evaluation and review.

2.1 Leak detection and repair regulations

Leak detection and repair (LDAR) is the general term for finding and fixing sources of leaks across the oil and gas supply chain — in the upstream oil and gas segment and in the mid- and downstream gas segments. Leaks (or fugitive emissions) are the most significant source of methane emissions from the oil and gas sector.[7] By their nature, they are difficult to predict and

[7] The source of leaks includes improperly fitted connections, deteriorated seals and gaskets, pressure changes, mechanical stresses, and poor maintenance or operating practices.

are widespread, thus frequent monitoring is key to reducing this source of methane emissions.[8] LDAR regulations aim to systematically detect fugitive emissions from oil and gas equipment, and require operators to perform repairs on the equipment where leaks are identified.

The first key design choice that affects the effectiveness of LDAR programs is the suite of technologies used for monitoring. An LDAR program that enables operators to employ traditional techniques (i.e., optical gas imaging inspection), or a combination of traditional and advanced technologies, will allow each operator to detect methane emissions in the most cost-effective manner. Optical gas imaging (OGI) involves on-site inspections (sometimes also referred to as surveys) using infrared cameras. Advanced technologies include aircrafts, unmanned aerial vehicles, mobile ground labs, continuous monitoring, and satellites. As these advanced technologies become less expensive and more widely available over time, they can provide a pathway for scanning broad geographic areas to detect the largest leaks more quickly and cheaply.[9] Still, traditional technologies have a lower detection threshold than advanced technologies and are most appropriate for monitoring smaller leaks.[10] A layered approach to LDAR can leverage the complementary nature of these technologies. Under such rules, operators use advanced technologies to detect large leaks and traditional technologies such as OGI to detect smaller leaks. These technologies can also be utilized by the regulatory agency to conduct audits and impose fines if methane leaks are detected.

The second key design choice that affects the effectiveness of LDAR programs is the frequency and coverage of leak detection inspections. The more frequently monitoring occurs across a larger number of sites, the more effective the LDAR program will be in finding leaks. Based on calculations tailored to the U.S., quarterly OGI inspections at well sites and more frequent (i.e., monthly) inspections at high-emitting sites such as compressor stations were found to be within an acceptable cost-effectiveness range using methodologies employed by the Environmental Protection Agency and the state of Colorado.[11] More frequent inspections may be appropriate if

[8] As monitoring capacity improves with projects such as Project Astra and MethaneSAT, the ability to predict methane emission leaks may improve.
[9] Environmental Protection Agency (2021a).
[10] See note 9, presentations by David Lyon, Erin Tullos, Matt Johnson, Triple Crown, Jonah, Project Astra, Project Falcon, BPX, Conoco, and Exxon.
[11] Comments submitted by Environmental Defense Fund et al., February 2, 2022, Docket ID No. EPA-HQ-OAR-2021-0317-0844, see attachment E, https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-0844; comments submitted by Environmental Defense Fund et al., March 3, 2022, Docket ID No. EPA-HQ-OAR-2021-0317-1432, see figure 7, https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-1432

cost-effectiveness (measured as cost per tonne of methane mitigated) improves with more frequent monitoring.[12] Some sites, such as those with low production, are sometimes exempt from LDAR regulations based on assumed low emissions. However, recent studies measuring actual emissions show that these smaller sites have disproportionately large emissions relative to their production volumes (Omara et al., 2022). This result suggests that broad LDAR coverage that avoids exemptions for smaller sites is important to ensure the regulations are effective in reducing emissions overall.

The third key design choice that affects an LDAR program's effectiveness is the way and timing with which repairs are conducted after a leak is found. Left unchecked, even small leaks can account for a significant amount of methane emissions. As such, all components found to be leaking methane during a survey should be repaired or replaced as soon as possible. With certain large or recurrent leaks, design or operational changes may be required to prevent recurrance. In these cases, engineering assessments and root cause analysis may be an appropriate component of the repair standards.

In the European Union (EU), the European Commission (EC) in December 2021 proposed methane regulations for the energy sector that would require quarterly LDAR. In the U.S., the Environmental Protection Agency has proposed, and some U.S. states (including California, Colorado, and New Mexico) have adopted, strong, comprehensive LDAR regulations that require frequent inspections at upstream and midstream oil and gas facilities. The most salient details of these regulations are summarized in Table 1.

[12] See also Kemp and Ravikumar (2021) for a discussion of cost-effective approaches to LDAR and the role of new technologies.

TABLE 1

LDAR regulations by jurisdiction

Jurisdiction	Coverage, technologies, and frequency	Repair timeline
European Union (proposed 2021)[i]	Rule applies to upstream and downstream facilities. Operators are required to conduct quarterly LDAR using devices that can detect leaks of 500 parts per million. Any detection technology or method is acceptable if it is equivalent to approved technologies and methods.	Leaks must be repaired immediately (no more than five days) after detection.
United States (proposed 2021)[ii]	Rules apply to oil and gas well sites (upstream) and compressor stations (upstream and midstream). **OGI only:** Sites with potential to emit (PTE) more than 3 tons per year (tpy) require quarterly monitoring. Sites with potential to emit (PTE) of 0-3 tons per year (tpy) are required to conduct a one-time monitoring survey. **OR** **Advanced + OGI:** Regulated sites conduct bimonthly advanced technology screens and annual OGI inspections.	First repair attempt within 30 days of leak detection. Final repair within 30 days of first repair attempt.
California (2017)[iii]	Rules apply to upstream oil and gas operations and transmission natural gas operations. Exceptions are made for certain components. **EPA Method 21:**[iv] Quarterly monitoring is required for tanks, separators, wells, and pressure vessels	14 days for leak threshold 1,000–9,999 parts per million volume (ppmv), 5 days for leak threshold 10,000–49,999 ppmv, 2 days for leak threshold > 50,000 ppmv.
Colorado (2021)[v]	Rules apply to oil and gas operations of well production facilities (upstream) and natural gas compressors stations (upstream and midstream). **OGI for well sites:**[vi] • Fugitive emissions of 0–2 tpy require annual monitoring • 0-2 tpy and within 1,000 ft of occupied area or in 8 hr ozone control area and within a disproportionately impacted community (DIC) require semiannual monitoring • 2–50 tpy require quarterly monitoring • 2–12 tpy and within 1,000 ft of an occupied area or within a DIC require bi-monthly monitoring • > 12 tpy and within 1,000 ft of an occupied area or within a DIC require monthly monitoring • > 20 tpy and without tanks require monthly monitoring • > 50 tpy and with tanks require monthly monitoring. **OGI for compressor stations:** • Fugitive emissions of 0–50 tpy require quarterly monitoring • 0–50 tpy stations that are within 1,000 ft of an occupied area or within a DIC require bimonthly monitoring • > 50 tpy require monthly monitoring.	First attempt within 5 days after detection. Follow-up monitoring 15 days after repair.[vii]

New Mexico (2021)[viii]	Rules apply to oil and gas production and processing equipment (upstream) and compressor stations (upstream and midstream). Operators may use OGI, EPA Method 21, or alternative approved inspection methods. **Well sites and tank batteries:** • PTE of < 2 tpy require annual monitoring • 2–5 tpy require semiannual monitoring • > 5 tpy require quarterly monitoring • All sites within 1,000 ft of an occupied area require quarterly monitoring. **Gathering and boosting stations:** • PTE < 25 tpy require quarterly monitoring • 25 tpy require monthly monitoring **Compressor stations:** Require quarterly monitoring	Repair as soon as possible but no later than 30 days after detection. Follow-up monitoring within 15 days after repair.

Notes
- (i) European Commission (2021a);
- (ii) Environmental Protection Agency (2021).
- (iii) California Air Resources Board (2017).
- (iv) EPA Method 21 refers to a methodology created by the EPA for targeting the detection of fugitive VOC emissions (also capable of detecting methane emissions) at oil and gas equipment. The EPA does not require the use of a specific technology but provides performance guidelines that must be met by the monitoring instrument. For details see https://www.epa.gov/sites/default/files/2017-08/documents/method_21.pdf
- (v) Colorado Department of Public Health and Environment (2021).
- (vi) Colorado regulations are effective starting Jan 1, 2023. Regulations in effect prior to this date are less stringent. See Colorado regulations for additional details.
- (vii) Colorado Department of Public Health and Environment (2020). Based on Colorado's previous LDAR regulations from 2014, the state found that 99% of detected component leaks were repaired over the course of 2018–2020.
- (viii) New Mexico Environment Department (2022). The ranges of PTE refer to VOC emissions.

LDAR regulations also exist in other jurisdictions. For example, in 2018 Mexico released the Guidelines for the Prevention and Comprehensive Control of Methane Emissions from the Hydrocarbons Sector to meet its target of 40–45% reduction in methane emissions from its oil and gas sector by 2025 (Mexico Agency for Safety, Energy and Environment, 2018). All facilities, new and existing, across the entire supply chain must develop a Program for Prevention and Integrated Control of Methane Emissions (PPCIEM). As part of each facility's PPCIEM, it must create and implement quarterly LDAR (IEA, 2022c). The regulation includes alternative compliance pathways and allows for the adoption of advanced technologies for emissions detection.

In addition, Colombia has become the first South American country to regulate methane emissions from oil and gas (Clean Air Task Force, 2022), with the adoption of the Ministry of Mines and Energy's Resolution MME 40066/2022 (Colombia Ministry of Mines and Energy, 2022). The regulation was finalized in February 2022 and aims to reduce fugitive emissions from upstream oil and gas activities at a national level. This new regulation includes instructions to carry out an LDAR to inspect oil and gas facilities. However, in its current form the regulation mandates only biannual LDAR.

2.2 Regulations on venting and flaring

While incidental leaks constitute a large portion of methane emissions from the oil and gas sector, another large portion of emissions stems from intentional operating practices where gas is disposed of as a waste product by:

(1) venting the gas to the atmosphere in its natural form (mostly methane); or

(2) flaring, i.e., combusting the gas and releasing carbon dioxide and other gases into the atmosphere, and where incomplete combustion of the gas means release of methane to the atmosphere.

The elimination of routine venting and flaring in all nonemergency situations could substantially reduce methane emissions from the oil and gas industry.[13] Ideally, the mitigated methane emissions would be captured and either sold, used on-site, or reinjected.

The first key design choice that affects the effectiveness of venting and flaring regulations is the extent of coverage with respect to when, where, and on which sources flaring and venting is allowed. Generally speaking, effective venting and flaring regulations eliminate the practice of routine venting and flaring, with a few limited exceptions. In upstream segments, effective regulations would restrict operators from venting except in emergency situations,[14] and when flaring would present a risk to safe operations or personnel safety. In addition, operators would be allowed to flare during upstream operations only in the following situations:

(1) emergency or unplanned situations with safety risks;

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[13] Venting and flaring is most common with the associated gas production at oil wells during the oil extraction process. Operators of these oil wells vent and flare the associated gas because they have not ensured adequate infrastructure to deliver the gas to market; according to the IEA (2022a), together with LDAR, zero non-emergency venting and flaring would achieve just under 40% points of the 70% total methane mitigation potential.

[14] Colorado Department of Natural Resources (2020). Colorado venting and flaring regulations define this as “a sudden unavoidable failure, breakdown, event, or malfunction, beyond the reasonable control of the Operator, of any equipment or process that results in abnormal operations and requires correction.”

(2) during completion operations if routing to a gas collection system would present a safety hazard; or

(3) during producing operations for narrowly defined planned repair and maintenance operations or other specified activities as defined by the regulatory body.[15]

In the mid- and downstream segments and in the absence of emergency and/or unplanned situations, operators should be allowed to vent or flare only during certain planned repair and maintenance operations or other specified activities as defined by the regulatory body. Furthermore, effective venting and flaring regulations should cover both new and existing sources. Finally, in the instances where flaring is permitted, a 98% flaring efficiency or higher should be required.[16]

The second key design choice that affects the effectiveness of venting and flaring regulations is the requirements for reporting of flaring and venting. Operators should report flaring and venting events whenever they occur. Ideally, this means operators will notify agencies no later than 24 hours before a scheduled event or within 12 hours after an emergency or unplanned event. Strong venting and flaring regulations would also require operators to report flaring and venting volumes regularly (e.g., monthly) and install the necessary measurement technologies to do so.[17] For flaring, an alternative to this system is a flare permitting system, where operators are granted a flare permit for a specific annual volume for each asset and are required to track their flaring against these permitted levels and engage the regulator early to negotiate any potential exceedances. This type of permit system is adopted in the U.K., Kazakhstan and Nigeria (Debbie Walker, pers.comm., 2022).

The proposed rules of the EC and the EPA regarding venting and flaring are summarized in Table 2, along with regulations implemented in Colombia, Mexico, Kazakhstan, and the U.S. states of Colorado and New Mexico.

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[15] Other production activities where flaring could occur include production evaluations, productivity tests, Bradenhead pressure tests, or only unloading.
[16] A study by Rystad Energy found that effective regulations banning routine flaring should be able to achieve a share of flared gas in total gas production volumes of 0.2% or below during the production phase (Rystad Energy, 2022).
[17] See Section 3 for more information on measurement, reporting, and verification of emissions.

TABLE 2

Regulations restricting venting and flaring by jurisdiction

Jurisdiction	Coverage	Reporting	Other elements
Colombia (2022)[i]	*Upstream* Flaring is allowed during exploration for testing purposes. Venting is prohibited in both exploration and production, although exceptions are granted for safety and maintenance.	Venting events and volumes, along with the underlying reason, must be reported, whether or not the event is planned.	
European Union (proposed 2021)[ii]	*Upstream, midstream, downstream*	Notification of nonroutine events. Quarterly reports of all flaring and venting events.	Installation only of combustion devices with an auto-igniter or continuous Pilot, and a complete destruction removal efficiency for hydrocarbons in newly built or refurbished facilities.
Kazakhstan (2017)[iii]	*Upstream and downstream* Flaring is allowed only during emergencies, well testing, trial operations, or in technically unavoidable circumstances.	Flaring events and volumes: Planned — any non-emergency flare requires a permit from the Ministry of Energy; Emergencies — within 10 days of event.	
Mexico (2018)[iv]	*Upstream and downstream* New and existing sources.	Authorization to flare associated gas must be included in the operator's approved exploration and development plans. Flaring events during well tests must be reported within 48 hours. Emergency venting and flaring: volume must be reported.	Requires facilities to replace or install zero-emitting venting equipment and prioritize capture technologies over flaring to reduce emissions from tanks and other equipment.
United States (proposed 2021)[v]	*Upstream* Existing sources.	No reporting required on individual flaring and venting instances.	Required 95% flare efficacy. Venting prohibited.
Colorado (2020)[vi]	*Upstream* New and existing sources	Events and volumes: Planned — 2 hours before; Emergencies — 12 hours after.	

New Mexico (2021)[vii]	*Upstream* New and existing sources.	Events and volumes Planned — monthly; Emergencies — 24 hours after.	Requires operators to install measurement technologies on certain equipment. Goal of 98% state capture rate by 2026 Ability to deny an Application for Permit to Drill if operator-specific capture rates not met, subject to outcome of hearing.

Notes

- (i) World Bank (2022a); Colombia Ministry of Mines and Energy (2022).
- (ii) European Commission (2021a).
- (iii) World Bank (2022b).
- (iv) Mexico's Agency for Safety, Energy and Environment (2018); World Bank (2022c).
- (v) Environmental Protection Agency (2021).
- (vi) Colorado Department of Natural Resources (2020).
- (vii) New Mexico Oil Conservation Commission (2021). The new rules added parts 19.15.27 and 19.15.28 to the administrative code. Part 27 regulates the venting and flaring from wells and production equipment and facilities. Part 28 regulates the venting and flaring from natural gas gathering systems.

Although more analysis is needed to assess how effective these regulations have been in reducing methane — and carbon dioxide emissions — in different jurisdictions, there is evidence that these rules can limit flared and vented volumes. For example, Colombia's new regulation to address methane emissions from oil and gas facilities — MME Resolution 40066/2022 (referred to in Table 2) — is only the latest among successive regulations dating back to the 1960s that prohibit gas from being wasted in Colombia. Between 2012 and 2021, the country reduced flaring from 1 billion cubic meters (bcm) to 0.3 bcm while steadily reducing its flaring intensity year after year (World Bank, 2022a). Meanwhile, thanks not only to its domestic gas market development, but also the strong enforcement of its regulations, Kazakhstan cut flaring from 4 bcm in 2012 to 1.5 bcm in 2021 — the largest flare reduction (by absolute volume) achieved by any country over the last decade (World Bank, 2022b).

In contrast, Mexico increased its flared gas volume by one-third and more than doubled its flaring intensity between 2012 and 2021, despite decreasing its domestic oil production by one-third (World Bank, 2022c). Although Mexico's 2018 Guidelines for the Prevention and Comprehensive Control of Methane Emissions from the Hydrocarbons Sector require facilities to prioritize capture technologies over flaring to reduce emissions from tanks and other equipment, the regulation does not establish a requirement limiting flaring of gas (Mexico's Agency for Safety, Energy and Environment, 2018).

Regulations to restrict venting and flaring also exist in other countries. Nigeria, which has consistently been among the world's top seven largest flaring countries by volume,[18] has set a policy target of zero flaring by 2030 as a conditional contribution in its national climate plan, updated in 2021. The 2018 Flare Gas (Prevention of Waste and Pollution) Regulations forbid routine flaring and venting for greenfield projects (Nigeria Department of Petroleum and Natural Resources, 2018). Furthermore, Nigeria's Petroleum Industry Act from 2021 allows flaring or venting for a specific period if either is required to start up a facility or for strategic operational reasons, including testing (Federal Government of Nigeria, 2021). However, no regulations have yet been issued to support this provision (World Bank, 2022d). All gas flared in Nigeria — whether routine or nonroutine, and whether the producer has the right to commercialize the gas or not — is also subject to a fee of US$0.5 per thousand cubic feet where daily oil production is less than 10,000 barrels or more, and US$2 otherwise.[19] These fees are calculated based on the gas flaring data submitted to the regulators. Nigeria's Guidelines for Flare Gas Measurement, Data Management and Reporting Obligations require producers to measure — based on metering[20] — all flaring and venting volumes on a daily basis (Department of Petroleum Resources, 2018). Producers are also subject to annual reporting on the composition of different gas streams, gas-to-oil ratios, associated gas utilization ratios, and routine and non-routine flaring quantities. According to the World Bank's Global Gas Flaring Reduction Partnership (GGFR) report (World Bank, 2022e), however, these statistics are not updated regularly on any public domain. As of December 2021, the last year for which data were available was 2018.

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[18] See the World Bank's Global Gas Flaring Data: https://www.worldbank.org/en/programs/gasflaringreduction/global-flaring-data

[19] Up until the latest Petroleum Industry Act, these fees were however cost recoverable and tax deductible making them less impactful (Debbie Walker, pers. comm., 2022).

[20] Section 3.9 of the Guidelines for Flare Gas Measurement, Data Management and Reporting Obligations provides for computation procedures during the transition period before the required meters are fully installed (Department of Petroleum Resources, 2018).

2.3 Equipment technology standards

While LDAR programs and regulation of venting and flaring practices can bring operators to upgrade their equipment, additional regulation can directly target high-emitting oil and gas equipment and infrastructure.[21] Such regulations require installing new devices or retrofitting existing devices to meet methane emission standards, typically on compressors, pneumatic devices, storage tanks, and liquids-unloading equipment.

The key design choice that affects the effectiveness of technology standards is how the equipment standard is specified. Technology standards will typically be more cost-effective if they mandate a certain emissions performance of the upgraded equipment rather than specify a certain technology to be used. This allows the operator the flexibility to use new and different types of technologies to achieve the required emission reductions cost-effectively.

Many technologies in upstream and midstream segments can achieve significant reductions in emissions of greenhouse gases (GHGs) and VOCs relative to traditional equipment.[22] For example, technology solutions already exist for a number of high-emitting sources. Emissions from these sources can be captured and routed to a process such as a vapor recovery unit to ready the gas for sale and achieve a 95% emissions reduction. Storage vessels can also achieve these reductions through the design of new tankless facilities. In addition, some technologies are capable of achieving zero emissions. Pneumatic devices driven by natural gas can be replaced with instrument air devices or electric devices (powered by the grid or solar) to achieve zero emissions, and numerous techniques and technologies used to perform liquids unloading can also achieve zero emissions.[23] The most salient details of specific U.S. and Canadian regulations are summarized in Table 3.

[21] These equipment and infrastructure sources include storage vessels, pneumatic controllers, compressors, and pneumatic pumps, and related work practices.
[22] These include wet-seal centrifugal compressors; existing pneumatic pumps in the processing segment; new and existing pneumatic pumps at production, transmission, and storage segments; and storage tanks.
[23] These technologies include manual unloading, velocity tubing or velocity strings, beam or rod pumps, electric submergence pumps, intermittent unloading, gas lift (e.g., use of a plunger lift), foam agents, wellhead compression, and routing the gas to a sales line or back to a process.

TABLE 3

Equipment technology regulations by jurisdiction

Jurisdiction	Emissions reduction requirement
United States (proposed 2021)[i]	**100% reduction of methane and VOC emissions:** Pneumatic controllers, pneumatic pumps (at processing plants), liquids unloading. **95% reduction of methane and VOC emissions:** Storage vessels, pneumatic pumps (except at processing plants), centrifugal compressors. **Replace rod packing or route to process at leak rate of less than 2 standard cubic feet per minute (scfm):** Reciprocating compressors.
Colorado (2021)[ii]	**100% reduction of VOC emissions:** New pneumatic controllers, all pneumatic controllers at processing plants. **95% reduction of VOC emissions:** Storage tanks, centrifugal compressors. **Phased replacement with non-emitting devices:** Existing pneumatic controllers (except at processing plants). **Replace rod packing every 26,000 hours of operation or every 36 months:** Reciprocating compressors. **Best management practice to reduce venting:**[iv] Liquids unloading.
New Mexico (2021)[iii]	**100% reduction of VOC emissions:** New pneumatic controllers. **95% reduction of VOC emissions:** Centrifugal compressors, storage vessels. **Phased replacement with non-emitting devices:** Existing pneumatic controllers **Replace rod packing every 26,000 hours of operation or every 36 months:** Reciprocating compressors. **Best management practice to reduce venting:**[iv] Liquids unloading.
Alberta (2021)[v]	**100% reduction of methane emissions:** Pneumatic pumps installed after January 1, 2022 that operate >750 hours per calendar year. **“Prevent or control vent gas” (control defined as 95% vent gas conservation, 90% of the time):** Pneumatic controllers and instruments.
British Columbia (amended 2021)[vi]	**100% reduction of methane emissions:** Certain compressor stations, pneumatic devices, pneumatic pumps installed after January 1, 2022 that operate >750 hours per calendar year. **95% reduction of methane emissions:**

	Hydrocarbon gas conservation equipment.

Notes
- (i) EPA (2021: table 2, pp. 63119–63120).
- (ii) Colorado Department of Public Health and Environment (2021).
- (iii) New Mexico Environment Department (2022).
- (iv) See notes (ii) and (iii). New Mexico and Colorado require the use of a best management practice to control venting associated with liquids unloading, which can include a plunger lift, artificial lift, control device, automated control system, or other approved control.
- (v) Alberta Energy Regulator (2021).
- (vi) B.C. Reg 282/2010, Oil and Gas Activities Act, Drilling and Production Regulation (amended March 4, 2021), p. 52, https://www.bclaws.gov.bc.ca/civix/document/id/crbc/crbc/282_2010

3. Methane monitoring, reporting, and verification

For any policy instrument such as a methane emission fee or a methane emission performance standard that, in contrast to the work practice and technology standards discussed in Section 2, is based on quantities of methane emissions, a methodology for the quantification of these emissions needs to be adopted. To enable the implementation of such policy instruments, this methodology also needs to be codified as a regulation for mandatory methane monitoring, reporting, and verification (MRV) that specifies how entities responsible for methane emissions should measure and report their emissions to the authorities. Such a supporting MRV regulation is a necessary prerequisite for any of the policy instruments discussed in Section 4.

To be able to track sector-wide methane emissions, a measurement-based MRV regulation would ideally obligate all entities along the oil and gas supply chain to report their methane emissions to the relevant regulatory agency. A robust measurement-based methane MRV regulation would thereby not only enable new policy instrument options, but also provide the opportunity to improve national GHG inventory data, which for methane are currently largely based on calculations using static emission factors (which in turn are multiplied by activity or component data to arrive at emission estimates). Static emissions factors are known to be both inaccurate and imprecise (Lackner et al., 2021) and typically result in underestimated emission estimates. Several empirical studies of U.S. methane emissions, for instance, indicate that the EPA Greenhouse Gas Reporting Program (GHGRP), which requires firms to estimate and report methane emissions from individual components (EPA, 1996), underestimates production emissions by as much as half of the actual total — and are extremely imprecise (Allen, 2014; Brandt et al., 2014; Zavala-Araiza et al., 2015; Alvarez et al., 2018).

3.1 A robust methane MRV methodology

Important features of a robust monitoring and reporting scheme for methane emissions include:

(1) a methodology based on direct measurement across varying spatial and temporal scales and statistically representative samples;

(2) a methodology that integrates top-down and bottom-up measurement data to validate emissions estimates; and

(3) emissions estimates reported with associated uncertainty.

The United Nation's Environment Program (UNEP) has developed a best-practice framework for methane emissions measurement and reporting called the Oil and Gas Methane Partnership (OGMP) 2.0 (see UNEP, 2020). Over 70 companies covering more than 50% of global oil and gas production have committed to reporting their methane emissions in accordance with the OGMP 2.0 framework for both their directly operated and nonoperated joint ventures.[24] In the OGMP 2.0 framework there are five levels of reporting, each of which becomes increasingly granular and scientifically robust, as described in Table 4.

TABLE 4

The five OGMP 2.0 reporting levels

Level	Description	Notes
Level 1	Emissions reported for a venture at asset or country level.	In other words, one methane emissions figure for all operations in an asset or all assets within a region or country.
Level 2	Emissions reported in consolidated, simplified sources categories.	Using a variety of quantification methodologies, progressively up to the asset level, when available.
Level 3	Emissions reported by detailed source type and using generic emission factors (EFs).	
Level 4	Emissions reported by detailed source type and using specific EFs and activity factors (AFs).	Source-level measurement and sampling may be used as the basis for establishing these specific EFs and AFs, though other source-specific quantification methodologies such as simulation tools and detailed engineering calculations may be used where appropriate.

[24] See the OGMP website for more information and a list of OGMP company members: https://www.ogmpartnership.com

Level 5	Emissions reported similarly to Level 4, but with the addition of site-level measurements.	Measurements that characterize site-level emissions distribution for a statistically representative population. Requires the use of site-level measurement to reconcile source- and site-level emission estimates.

Source: UNEP (2020)

The gold-standard Level 5 reporting requires the use of methane measurements that create a site-level emissions distribution for a statistically representative population of sites and also requires reconciliation of bottom-up (e.g., source-level) and top-down (e.g., site- or regional-level) emission estimates.[25] OGMP member companies commit themselves to reach Level 5 reporting within a period of three years for operated ventures and five years for nonoperated joint ventures.

Participation in OGMP 2.0 is voluntary, but the gold-standard Level 5 has served as a best-practice example in regulatory discussions around how to design MRV regulations for methane emissions for both upstream, midstream, and downstream assets. The EC's proposal for a methane MRV regulation in the EU is largely aligned with the OGMP 2.0 reporting framework. As a voluntary framework, OGMP 2.0 lays out a methodology for monitoring and reporting of methane emissions. In addition, the EC proposal lays out what a verification approach could look like.

The EC proposal describes the role and procedures for verifiers of the reported emissions data. Verifiers must be "third-party organizations" with no link to the owners or operators of the asset, the owners of the commodity, or the competent authorities. Independent accredited verifiers should review the data in the emissions reports prepared by operators to assess their accuracy and credibility against publicly available European or international methane emissions quantification standards. Operators are required to provide the verifiers access to the premises for site checks and the presentation of documentation or records (European Commission, 2021a).

Verifiers must also be accredited by a national accreditation body (NAB — one single not-for-profit accreditation body per EU member state) in accordance with European Commission Regulation No 765/2008 (see European Parliament and European Council, 2008), which sets out common rules for accrediting bodies that ensure nonfood products in the EU conform to

[25] Top-down estimates may rely on aerial, satellite, or tower networks to aggregate emissions estimates across large geographies. Bottom-up estimates extrapolate and aggregate measurements taken at a piece of equipment or directly downwind of a facility. See Alvarez et al. (2018) for details.

certain requirements. These NABs are entitled to determine whether verifiers are competent to conduct their work, to monitor their performance, and to restrict, suspend, or withdraw accreditation certificates for those that become unable to carry out their duties. Furthermore, the NABs are required to collaborate with one another, under the management of the European co-operation for Accreditation, through peer evalution and to regularly make public information on their work (European Commission, 2021a).

The EU approach with accredited third-party verifiers is one option for a verification design. Another option is having the relevant regulatory agency (e.g., the country's environmental protection agency) do the verification and auditing itself. Regardless of which approach is chosen, the entities responsible for verification need to have the necessary competence and knowledge of methane emissions to carry out robust verification. The required verification competence goes beyond a simple auditing of reported numbers, and involves an understanding of appropriate sampling techniques and different types of methane measurement technologies and the nature and quality of data they generate.

Aerial and remote sensing data such as from methane-detecting aircrafts, drones and satellites will be particularly valuable from a verification standpoint as these technologies can provide independent third-party measurements that can be used to corroborate emission estimates reported by companies. In particular, remote sensing data can be used for verification at the regional level and in some cases for high emitters at the site level. In fact, UNEP's International Methane Emissions Observatory (IMEO) will be using remote sensing data to corroborate the data voluntarily submitted to it by OGMP member companies. While IMEO is not taking on the role of verifier, the remote sensing data it provides could be used by third-party verifiers and regulators for verification of emission reports submitted under an MRV regulation. Furthermore, remote sensing data can allow regulators to more effectively target auditing of submitted MRV reports (see Werner & Qui, 2020) — in particular for prioritizing auditing across regions and, in the case of high-emission events detected with remote sensing, across individual sites.

3.2 Mitigation incentives under MRV regulations

An MRV regulation like the one included in the EC proposal could, even if not used as a basis for implementing any of the policy instruments discussed in Section 4, potentially provide some methane emission reduction benefits on its own, by:

(1) increasing transparency within the companies subject to the MRV regulation and helping them identify previously unknown opportunities for low-cost gas capture and methane mitigation; and

(2) including public information disclosure. This could be considered a policy instrument in itself and be used to put public pressure on companies to address methane as well as show what can be achieved using methane-control practices adopted by companies that operate according to industry best practice.

The OGMP 2.0 initiative includes relatively stringent confidentialty requirements, whereby reporting is conducted by a "reporting unit," with public disclosure only on a consolidated corporate basis. Some of its provisions therefore prevent transparency around emissions from individual assets in a supply chain (Stern, 2022). This limits the potential benefits of data from OGMP 2.0 being used as an information-based policy instrument, which requires transparency to be fully effective. To make their MRV regulations more effective as a policy instrument, policy makers have the option to go beyond the consolidated corporate reporting in OGMP 2.0 and include more granular data reported under the MRV regulation available to the public.[26] This would enable more detailed media reporting on companies and assets responsible for large emissions, as well as facilitiate new research studies.

Rather than encouraging additional mitigation, an MRV methodology can lead to adverse mitigation incentives when its based on emission factors rather than direct measurement. This is particularly relevant when the MRV reports are in turn used as a basis for a policy instrument that puts an emissions price on each unit of emission (see the policy instrument examples in Section 4 and the discussion in Lackner et al., 2021). For example, if an emission price is levied based on component-specific emission factors, it would incentivize firms to change system components that affect their reported emissions (and thereby their methane payment liability),

[26] Industry concerns about confidentiality and disclosure of data that they consider sensitive from a competitiveness standpoint could, for example, be addressed by disclosing data after some time lag.

as opposed to targeting their actual emissions. Firms may, for example, install components with low emissions factors that result in lower *reported* emissions, but they would not be incentivized to improve operational and maintenance practices that could lower their *actual* emissions further. Some of these component upgrades may, in fact, fail to reduce emissions at all. For instance, a firm with poor operations and maintenance procedures may not emit less, even after installing component upgrades. This could occur either through improper use of the new equipment, or because the firm has leaks in its system that are not addressed by the upgrades and that continue to worsen. In the end, firms may bear the costs of investment without actually achieving any reduction in methane emissions. This example illustrates why methane MRV should, as far as possible, be based on direct measurement of methane emissions and on the type of granular reporting specified in the gold-standard OGMP 2.0 Level 5.

Key to effective MRV approaches that can provide the right mitigation incentives is representative sampling, with data collected at more than one scale and where regional-level satellite or aerial top-down data from aircraft or drones can be used for verification of bottom-up emission estimates (which can also be combined with verification using more traditional on-site inspections using OGI). For example, research indicates that 8–12% (~8 million metric tonnes of methane per year) of global oil and gas methane emissions come from extreme high-emission events — so-called super-emitters — from the world's largest oil and gas basins (Lauvaux et al., 2022). These low-probability, high-emitting events can be found across regions and in different segments of the supply chain — upstream, midstream, and downstream — and at various points in time. In this regard, methane-sensing satellites with the capacity to map any area regardless of its location and ground accessibility have proven to be a powerful tool. Scientific studies have demonstrated that satellites offering global mapping capacity on a near-daily basis can detect and quantify super-emitters (UNEP, 2021).

There are different options for how to regulate these stochastic high-emission events, which also depend on where the event is detected. In countries that have already implemented a methane MRV regulation, the emitting entity could be required to include the emissions from the detected event in their annual MRV report to the regulator. If the country has also adopted a policy instrument that puts an emissions price on each unit of emissions reported under the MRV regulation, this price could then also be levied on the emissions from these stochastic events. Another option is implementing dedicated penalties for these types of events, which should be set proportional to the amount of the emission and be sufficiently high to incentivize frequent monitoring and regular LDAR in order to prevent them in the first place.[27] In general, the lower the probability of detection, the higher the fee or penalty required to incentivize work practices and investments that will reduce their probability of happening.

For addressing high-emission events in countries that have still not implemented stringent methane regulations, the approach would instead need to be based on public information disclosure of these events through media and other impactful channels. This would incentivize the individual operator to address the source of the emissions and put pressure on the relevant country's policy makers and regulators to strengthen their methane regulations and enforcement.[28]

3.3 Certification programs for low methane emissions

MRV regulations are typically implemented to cover domestic emissions. There are instances, such as the EU's MRV regulation for the shipping sector, that also cover extraterritorial emissions.[29] However, extending monitoring and enforcement of an MRV regulation to non-domestic emissions, such as footprint emissions related to oil and gas imports, is typically more challenging.

In addition to an MRV requirement for domestic sources, the EC's proposal for regulating methane emissions from the energy sector includes a requirement for importers of fossil fuels to provide information on the measurement and reporting of emissions by the exporter and on any regulatory or voluntary measures to control emissions. The objective is to use this information to create a methane transparency database and a so-called methane supply index (MSI). The MSI is intended to empower buyers of fossil fuels to make informed purchasing decisions on the basis of the methane emissions of the purchased fuel (European Commission, 2021a). In other words, the MSI can be considered an information-based policy instrument.

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[27] Potential issues to consider when choosing between these options is that, for a methane pricing system based on emission trading, right-tailed super-emitting events could blow through the emissions cap, which may be a reason to regulate super-emitting events separately or opt for a methane fee rather than an emission trading system.
[28] See Lavaux et al. (2022) for examples of satellite detecting super-emitter events around the world.
[29] In this instance, these are international emissions from shipping that fall outside national GHG inventories of domestic territorial emissions submitted under the United Nations Framework Convention on Climate Change (UNFCCC).

How this requirement to report information on oil and gas imports will work in practice is still an open question. A particular challenge for tracking non-domestic emissions is that the oil and gas commodity often changes owners soon after it has been extracted and transactions can be especially complex when it is exported. Increased global LNG trade is also drawing attention to the need for transparent accounting of supply chain methane emissions.[30]

In this context, programs that certify natural gas or petroleum as having been produced with low methane emissions are a potential lever for tracking and addressing footprint emissions. Low methane certificates could, for example, be required to comply with a policy instrument such as a methane portfolio standard for natural gas (see Section 4.2.2) or be used to meet market-driven demand for fossil fuels with low methane footprints. A certificate system also makes it possible to unbundle the emissions characteristic of the oil and gas from the physical oil and gas commodity so that the emission characteristics of an oil and gas portfolio can be traded separately from the commodities themselves.

In contrast to an MRV regulation, however, certification systems are typically voluntary and opt-in, meaning that companies can choose whether to participate and which facilities to certify. In theory, producers are incentivized to certify only if the cost of doing so is lower than the value to the company of the higher price it can get for certified gas. This selection effect is a major weakness of voluntary certification programs, since companies are more likely to certify gas from facilities with already good emission performance rather than carry out additional mitigation.

To credibly argue that their certificates that guarantee the gas (or petroleum) products have been produced with low methane emissions, voluntary programs must adhere to strict design guidelines:

(1) certification standards should match the OGMP 2.0 Level 5 reporting requirements discussed in Section 3.1; and

(2) as these programs are not overseen by a regulatory body, verification of emissions estimates should be carried out by a truly independent and accredited third party.

[30] See Stern (2022) for a discussion of the EC's proposal for methane reporting and on emerging initiatives to track GHG emissions from global LNG trade.

At present, no such verifiers nor such an accreditation body with the necessary methane expertise exist, but potentially the approach to verification proposed by the EU (see Section 3.1) may offer a model for what this could look like also outside the EU. In addition to these MRV criteria, there must be clear and transparent guidelines around the emissions threshold that constitutes “low-methane” gas — for example, by using the established methane emission intensity definition and threshold from the Oil and Gas Climate Initiative (OGCI).[31] The establishment of a global standard for certification and associated verification and accreditation could help overcome some of the complexity and transparency issues related to certification of low methane emissions.

To address the concern around companies choosing to certify gas from already low-emitting sites within their portfolio, certification programs should also require participating companies to report on which assets they are certifying and provide clarity regarding how these assets compare with their entire portfolio. Note that due to this selection effect, even a high-integrity certification program that fulfills the criteria outlined here might still provide limited incentives for additional abatement. For addressing domestic emissions, MRV and direct regulatory and policy interventions are therefore strictly preferred to voluntary certification programs.

Certification programs in an international context are also likely to suffer from emission leakage and limited additional incentives for abatement due to this selection effect. Gas produced from, say, a low-emitting field in Australia could be certified to meet the methane emission requirements of a particular gas-importing market, but gas from another field in the same country with higher emissions could be shipped to another market without similar methane requirements on their gas imports.

In cases where producers are locked in to certain markets for some of their gas assets due to existing pipeline infrastructure, this leakage risk could be somewhat mitigated. However, with the growing global market for LNG, producers will increasingly have the option to offload their gas in markets without methane emission requirements — unless such requirements cover a very large share of the global gas market (see also the discussion in Section 4.2.5).

[31] Oil and Gas Climate Initiative Reporting Framework 3.3, October 2020, p. 15, https://www.ogci.com/wp-content/uploads/2020/10/OGCI-Reporting-Framework-3.3-October-2020.pdf.

4. Addressing upstream emissions: policy options based on methane emission quantification and MRV

Research suggests that the largest and most cost-effective reduction opportunities in the oil and gas sector lie upstream in the production and processing segments. Based on findings from the U.S., mid- and downstream emissions from gas transmission and distribution infrastructure are likely to be a relatively smaller share of total oil and gas supply chain emissions (see, e.g., Alvarez et al., 2018; Weller et al., 2020).[32] The mid- and downstream segments also present additional regulatory considerations because these segments are typically operated by revenue-regulated system operators. These operators need approval from their energy market regulator to incur costs and recover them from their customers, which also affects their incentives to address methane emissions from their facilities. We therefore discuss mid- and downstream emissions separately in Section 5, and in this section focus on upstream emissions from the production and processing segments.

Policy instrument options for addressing upstream emissions will differ for oil- and gas-producing countries for which these emissions are domestic and arise within their own territory, compared to countries that primarily rely on imports for their oil and gas needs. Environmental policy instruments are most likely to be effective in reducing emissions when their point of obligation (i.e., the entities obliged to comply with the policy instrument) are the entities directly responsible for the emissions. Making the polluter the point of obligation for upstream emissions is an option in oil- and gas-producing countries but typically not in oil- and gas-importing countries. The point of obligation in the latter will instead typically need to be entities on the importing/buyer side that are based inside the jurisdiction's own territory. In addition, the policy instrument options available for oil- and gas-importing countries are also guided by the limitations to enforcement of an MRV regulation for upstream non-domestic emissions, as discussed in Section 3.3.

Figure 1 illustrates the methane emissions along the oil and gas supply chain, the responsible polluter (and ideal point of obligation) in the different segments, and how the policy levers vary

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[32] The actual distribution of methane emission across segments in different international and national gas supply chains is ultimately an empirical question. Exceptions where mid- and downstream emissions represent a larger share may, for example, exist in regions with particularly old and leaky gas pipelines and distribution grids.

for different segments depending on whether the emissions arise in the oil- and gas-producing or oil- and gas-consuming country.

We start by outlining policy instrument options for addressing upstream emissions in oil- and gas-producing countries in Section 4.1, and then discuss options for oil- and gas-importing countries in Section 4.2.

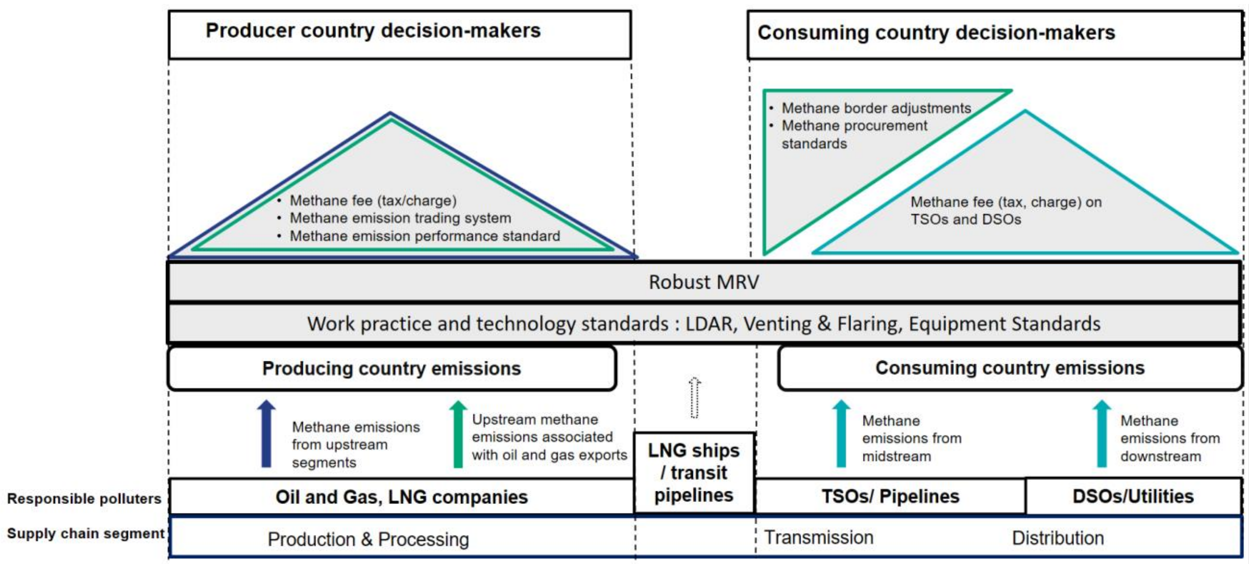

FIGURE 1

Policy and regulatory levers for addressing methane emissions across the oil and gas supply chain. When the oil or gas comes from domestic production, the consuming country is the same as the producer country and the country's decision-makers can regulate the whole supply chain. However, in a federal country the different segments may still be regulated by different legislative and regulatory bodies at the federal and state levels.

4.1 Policy instrument options for oil- and gas-producing countries

The policy instrument options for addressing domestic emissions in oil- and gas-producing countries discussed in this section all include a price per unit of emissions, be it implemented as a methane fee, an emission trading system, or a methane performance standard. An advantage of these policy instruments compared to the prescriptive regulatory options discussed in Section 3 is that they give firms more flexibility in terms of which mitigation options to use in order to comply with the regulation. This is because a price per unit of emissions encourages all firms to find and exploit variation in mitigation costs and options across their portfolios. Available data suggest this variability does exist (ICF International, 2014, 2016; Munnings and

Krupnick, 2017; Marks, 2022). Because the emission price signal encourages firms to reduce emissions cost-effectively on their own, the regulator does not need to know which abatement options are cheapest or which firms can implement which abatement approaches. This flexibility reduces overall mitigation costs and may thereby also make the achievement of more ambitious emission targets possible (see also Lackner et al., 2021). Policy instruments that are based on methane emission quantification and MRV also have the advantage of directly providing data to track the country's domestic emission levels over time, and even the option to design the policy instrument itself to ensure stated methane-reduction targets are met.

In this section, we discuss methane pricing in the form of methane fees and emission trading systems (ETSs), as well as methane performance standards (tradable and nontradable). These instruments have many features in common, which we discuss before going on to outline the main distinguishing features between these options.

4.1.1 Shared features of policy instrument options for domestic emissions

There are a few key design choices common to all the policy instrument options targeting domestic upstream methane emission from the oil and gas sector. The first, and perhaps most consequential, is the design of the MRV approach. As discussed in Section 3, MRV regulations are a prerequisite for implementation of policies that rely on emission quantification. To be most effective in targeting emissions, the MRV would ideally be based on actual and continuous emission measurements. Until such measurement technologies are available for all sources, the design should still be based on methane measurements and representative sampling and aligned with the features of OGMP 2.0 Level 5 reporting (see Section 3.1).

In cases where MRV in line with OGMP 2.0 Level 5 is not considered feasible to implement — at least in the short term — policy makers also have the option to leverage remote sensing data from aircraft or satellite measurements to estimate regional (i.e., field, production area or basin) emissions. Using measurements sampled to estimate annual total methane emission estimates for a production area, producers active in that area could then be attributed a share of the area's total emissions — based, for example, on their share of the area's total oil and gas production — and be liable to pay the methane emissions price on the share of total emissions assigned to them. Firms that actually emit less than the emissions assigned to them would, however, be unfairly penalized under this approach and could therefore be provided the option to submit an MRV report that has been verified using scientifically robust methods in line with OGMP 2.0

Level 5 or equivalent.[33] A similar design to address negative externalities from production with known aggregate emissions and unobserved individual firm contributions is discussed in Cicala et al. (2021). Using data from oil and gas production in the Permian Basin of New Mexico and Texas, the authors analyze a methane fee that is levied on each barrel of oil equivalent using the average per unit share of total emissions for the production area. This fee is then combined with the option to certify emissions (using a robust MRV method). According to the authors, this methane fee design can replicate the same emissions outcome and social welfare gains as a methane fee with full information on individual firms' emission contributions. This policy design which leverages remote sensing data to assign emissions to the compliance entities could also be used for methane included in an ETS or an emission performance standard.

The second choice is whether to combine the instrument with prescriptive regulations, such as work practice standards. In theory, it is possible to design a policy instrument that can, on its own, achieve at least the same amount of mitigation as a work practice or technology standards. However, given that continuous methane emission quantification is not yet technically possible and monitoring therefore needs to rely on representative sampling, methane emissions data reported under an MRV regulation will still have some degree of related uncertainty. Work practice standards such as LDAR and restrictions on venting and flaring (described in Section 2) can, in that context, provide a backstop by ensuring all operators take actions to prevent methane emissions. Furthermore, as noted in Section 2, oil and gas production also emit local air pollutants such as VOCs and HAPs. Ensuring that all sites are reducing emissions will protect nearby communities from experiencing exposure to such local air pollution. It may therefore be attractive to combine the chosen policy instrument with work practice standards. The objective of the policy instrument would then be to provide additional incentives for mitigation beyond that achieved with those standards.[34]

A third key design choice is the scope of the policy — i.e., its coverage. Ideally, the chosen policy instrument would cover all entities responsible for any upstream emissions, including smaller

[33] As cleaner firms opt out and reduce their emission liability, liability for remaining firms should increase to correspond to total basin-level emissions. Over time, this policy design would continuously strengthen the incentives to mitigate emissions and report them in accordance with best available MRV standards.

[34] This uncertainty in reported methane emissions may also be an argument for using fees over a tradable policy instrument. With an ETS or a tradable performance standard, underreporting of actual methane emissions in effect frees up allowances for others, allowing more emissions and undermining the emissions price (Carolyn Fischer, pers. comm., 2022).

operators. As noted in Section 2.1, smaller operators are sometimes subject to exemptions, which may leave large gaps in policy coverage. A methane fee or an ETS can also be extended to cover domestic mid- and downstream entities. We discuss this option separately in Section 5.

4.1.2 Methane emission pricing through an emissions fee

We start by discussing the environmental policy instrument that is conceptually simplest and perhaps most commonly used: an emissions fee (or charge/tax).[35] As discussed in the introduction to this section, a price per unit of methane emitted increases companies' private incentives to capture methane above the market value of the gas. Furthermore, it incentivizes them to seek out mitigation options that provide abatement at lower cost than the combined value of the emission price and the market value of any captured natural gas.

An important design choice that determines the effectiveness of a methane fee is naturally the level of the monetary penalty per tonne of methane emitted. A relevant reference point for the choice of emission price level is the so-called social cost of methane (SCM), which is an estimate of the social damages associated with one additional unit of methane emitted to the atmosphere. The Biden administration's Interagency Working Group on the Social Cost of Greenhouse Gases (IWGSCGG) provides an estimate of the SCM of US$1,500 per tonne of methane, using 2020 as a baseline and a 3% average discount rate (IWGSCGG, 2021).[36]

Another relevant reference point for choosing the level of the methane price is the cost of mitigating methane. A lower emissions price than the SCM – which is particularly relevant to consider in developing countries - would still provide an abatement incentive as long as it is higher than the per unit abatement cost (net of the market value of any captured natural gas). One recent study demonstrates the importance of choosing an emissions price that is high enough. In this, Prest (2021) uses an economic model to estimate the effects if the proposed U.S. Congress methane fee were implemented at different levels.[37] In particular, the author simulates

[35] The distinction between an emissions fee, charge, or tax can be important from a legal and regulatory perspective depending on the jurisdiction where it is implemented. However, from an economics standpoint — which is the focus of this paper — the abatement incentive effects of a penalty per unit of emissions are the same regardless of the legal or regulatory framework used to implement it.

[36] Additional academic studies present alternative approaches to calculating the SCM, sometimes resulting in higher estimates. A paper by Errickson et al. (2021) estimates equity-weighted SCMs, which account for the relative dollar value of consumption lost for regions of differing income levels. The study estimates that the US SCM increases from US$933 per ton to US$8,290 per ton when using equity weights.

[37] For further details, see https://www.congress.gov/bill/117th-congress/house-bill/5376/text

how much producers might reduce their methane emission intensity and how much the marginal cost of producing a unit of gas might increase under different methane fees ($ per tonne of methane). The study finds that low methane fees of US$500 per tonne of methane would have low emission reduction effects (33–45% below baseline), while methane fees of US$1,000–1,500 per tonne of methane may generate significant reductions in methane emissions (44–75% below baseline).[38] While higher fees lead to more emission reductions, they do so with diminishing returns, because smaller emission sources are more difficult to identify and address.

Regardless of the initial emission price chosen, the fee could be adjusted upwards over time to incentivize additional abatement and emission reductions in line with stated methane-reduction and climate targets. This possibility of adjusting the fee level is important in case the emissions data reported under the MRV regulation indicate that the fee is too low to incentivize sufficient mitigation to reach these targets.

Finally, the monitoring and enforcement of any policy based on financial penalties will be particularly important given the uncertainty in emissions and that a small number of sources tend to be responsible for a large share of total emissions (see e.g., Alvarez et al., 2018, and Duren et al., 2019). In the absence of continuous emissions monitoring, the effectiveness of a methane fee in terms of its abatement incentives and ultimate impact on emissions will depend on the likelihood for firms of getting caught misreporting their emissions, the penalties for doing so and the fee charged per unit of detected emissions. The lower the probability of detection the higher the penalties and fees required (Carolyn Fischer, pers.comm., 2022).

Some countries have already implemented taxes or charges on methane emissions from the oil and gas sector. Norway's 1991 carbon tax also covers methane emissions (as releases of natural gas to air) from offshore oil and gas production. The tax rate in 2021 was NOK 8.76 per standard cubic meter of emissions of natural gas (Norwegian Petroleum, 2021), which is equivalent to approximately US$1,600 or € 1,500 per tonne of methane.[39] As for Norway's associated MRV approach, methane emission reporting regulations introduced in 2001 and amended in 2012 require the installation of metering systems to obtain methane measurements for tax purposes for certain emissions sources, while other sources are still calculated based on emission factors

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[38] Baseline emissions intensities and resulting reductions reflect the full supply chain emissions intensity range reported in Alvarez et al. (2018). The methane fee scenario includes a 0.25% leakage allowance.
[39] Assuming 90% methane content of natural gas and currency conversion rates of EUR 1 = US$1.06 = NOK 9.81.

(IEA, 2022b). Around two-thirds of emissions are accounted for by direct measurements such as flow meters on vent heads. For the other one-third, non-metered emissions, operators must follow recognized quantification models and methods to compute emissions (IEA, 2020). Recent methane measurement studies suggest that Norway's approach to methane accounting from its offshore facilities has indeed been successful for understanding the key emission sources at the facility level and managing the emissions accordingly (Foulds et al., 2022).

Russia introduced environmental charges in the 1990s that cover methane emissions under a three-level fine system. The base charges for methane are ₽ 50 (US$1.57) per tonne for emissions within the emission limit value, ₽ 250 (US$7.85) for emissions within the temporary limits (which are five times higher than the emission limit values), and ₽ 1,250 (US$39.25) for emissions above the temporary limits.[40] In 2005, the methane fines increased tenfold. Companies can submit their own emission estimate methodologies under this regulation. Not all methodologies are publicly available, but the dominant gas producer, Gazprom, published a 2010 methodology that relies on average emissions factors (Evans and Roshchanka, 2014). Gazprom also publishes methane emissions by supply chain segment in its environmental reports, which state very low emissions intensity (Stern, 2022). There are open questions around how effectively Russian authorities are monitoring and enforcing this policy (e.g., Mufson et al., 2021).

Kazakhstan's Environmental Code (2007, 2011) imposes emissions taxes using base levies for various emissions, including those from flaring, provided in Article 576 of the 2017 Tax Code of Kazakhstan (Kazakhstan Ministry of Justice, 2017). The base tax rates for methane emissions from incomplete flaring are 80 times greater than methane emissions from other stationary sources. The tax code enables local authorities to raise the rates by more than twice for emissions from flaring (Paragraph 8, Article 576). For 2021, the payment for emissions of methane from flaring within a permitted limit constituted KZT 2,333 (US$5.51) per tonne of methane.[41] These taxes are calculated based on the gas flaring volume submitted to the regulators. Operators are required to measure emissions using acceptable metering

[40] Dollar conversions were directly extracted from Evans and Roshchanka (2014), reflecting currency values before 2014 with a non-specified base year that hinders conversion to real values in 2022 currency.
[41] Based on the fee of 0.8*monthly calculation index per tonne of methane. A monthly calculation index of KZT 2,917 was set by the government for 2021 (Ernst & Young, 2021). The monthly calculation index is used by the tax authorities when estimating taxes, fees, and other payments in Kazakhstan. Currency exchange rate: US$1 = KZT 423.7.

methodologies or, in cases when metering is not feasible, allowed calculation methodologies established in the Environmental Code. According to Article 418 of the code, facilities operating before July 1, 2021 must install automated systems for monitoring emissions before the end of 2022. In contrast to emissions from flaring, there is no explicit mention of methane emissions from venting or leakage sources in Kazakhstan's Environmental Code.

4.1.3 Methane emission pricing through an emission trading system

Methane pricing can also take the form of inclusion in an emission trading system (ETS or cap-and-trade program). The main difference between this and a methane fee is that the emission price level under an ETS is not the direct choice of the policy maker but is instead determined by the size of the emissions cap and the demand for emissions allowances, as well as any price management mechanism included in the ETS design.[42] The design of the supporting MRV regulation for methane, the uncertainty in reported emissions and the associated enforcement approach will also influence the emission price.

Methane pricing through an ETS can be established by either introducing an ETS specifically dedicated to methane emissions or by having methane emission sources covered by a broader ETS that includes several GHGs. Having an ETS specifically dedicated to methane would make it possible for the policy maker to set a methane-specific emission cap and thereby choose the total amount of methane emissions allowed. This would be particularly valuable if the policy maker wanted to ensure that a previously defined methane-reduction policy target was met.

In contrast, when including methane in an ETS that also covers other GHGs, the policy maker chooses the cap for the total amount of GHGs. The amount of methane abatement and remaining amount of methane emissions induced by the policy will thereby be determined by the market price of emission allowances relative to the cost of abating methane emissions and the conversion rate used for methane relative to other GHGs. When considering including methane emissions in an ETS for other GHGs, policy makers also need to keep in mind that any issues with respect to MRV and uncertainty in emissions – and any market concentration among a small number of methane emitters responsible for a large share of emissions - may spill

[42] Such a price management mechanism could, for example, be a compliance reserve or a price ceiling or floor. All mature ETSs have some form of price management mechanism included in their design. In addition, demand for emission allowances is a function of several factors, including the abatement costs across the covered sectors, macroeconomic developments, and other features of the ETS design itself (e.g., allowance banking). For further discussion, see, e.g., World Bank (2021).

over and affect the mitigation incentives for other GHG sources covered by the ETS (Carolyn Fischer, pers.comm., 2022).

An important design choice when including methane in an ETS that also covers other GHGs is the rate used to convert tonnes of methane into tonnes of carbon dioxide equivalent (CO_2e, the emissions unit typically used for GHG emissions allowances in an ETS). Similarly, the choice of conversion rate is also relevant when deciding on the level for a methane fee given the emission prices already imposed on other GHGs. Existing ETS programs commonly use global warming potentials (GWPs) with a 100-year time horizon (GWP100), in which a tonne of methane is considered equivalent to 25–30 tonnes of carbon dioxide (depending on which Intergovernmental Panel on Climate Change assessment report is being used as reference for the GWPs). As an illustration, using instead a GWP with a 20-year time horizon (GWP20) for methane of 83 (from the latest assessment in Intergovernmental Panel on Climate Change [IPCC], 2021) would strengthen the incentives for methane abatement relative to carbon dioxide because the price of methane relative to carbon dioxide would be close to three times higher than when using a GWP100 for methane.

To date, no ETS has been designed to solely cap methane emissions. New Zealand includes fugitive methane emissions from coal mining and gas production in its ETS (Rontard and Leining, 2021). Allowance obligations are based on default emission factors, but underground coal-mining sources can apply for a unique emissions factor. Such emissions factors have not yet been used and this is a very small sector with few sources in New Zealand.

Another option available to policy makers in a country with an ETS for GHGs is including methane emissions from the oil and gas sector in an emission credit market. Adding an emission credit market that allows for trade in credits for emission reductions by entities not covered by the ETS cap can be attractive. This is because it can allow a GHG emission reduction target to be achieved at lower economic cost, or enable a more ambitious GHG reduction target by allowing credits for emission reductions in sectors outside the cap that have comparatively lower mitigation costs.

However, emission credit markets come with their own set of policy design challenges. First, issuing emission reduction credits for an intervention or project requires an estimation of business-as-usual (BAU) emissions — i.e., an assessment of what the emission level would have been without the project. This is generally difficult to ascertain, but given the limited direct measurements of methane emissions available at the source level, it would be particularly difficult to establish a credible methane emission BAU at a project level and thereby determine the number of emission credits to issue. Companies have better information about their intentions and capability to reduce methane, so it is difficult for a regulator to negotiate an unbiased baseline BAU with industy.

Second, because participation in a credit market is voluntary, it would most likely attract those entities that would already want to reduce their methane emissions because there are private benefits for them to do so. This selection effect, combined with the first challenge of establishing an unbiased BAU estimate, would mean that there might be only limited *additional* emission reduction generated by allowing for emission credits based on estimated methane reductions.

Additionality is especially difficult for carbon dioxide and methane emissions from the oil and gas sector because there is almost always an economic benefit for companies in addressing such emissions, even without the existence of a GHG credit market. For example, companies can capture associated gas and use it to produce electricity, and through reducing flaring or by plugging leaks to address fugitive emissions and bring the gas to market, they can increase efficiency of their operations or generate additional revenue. The use of the recovered gas (particularly how it will replace other sources of energy on the margin) and the related impacts on GHG emissions will also affect the additionality of the project (Pedro Barata, pers. comm., 2022). Credits for all three types of measures have taken place under the Clean Development Mechanism[43] and the joint implementation mechanisms of the Kyoto Protocol.

A third challenge with emission credit markets is that establishing a baseline as well as monitoring and verifying emission reductions for each project implies significant transaction costs, which would be burdensome for smaller actors and in countries where government institutional capacity is limited.[44]

[43] Clean Development Mechanism methodology AM0009 and AM0037, United Nations Framework Convention on Climate Change.

[44] The choice of conversion rate for methane credits has the reverse effects in a credit market compared to when methane emissions are included under the ETS cap. Using our previous example of a GWP20 of 83, only 0.012 tonnes of methane would need to be reduced to offset 1 tonne of carbon dioxide, as compared with 0.034 tonnes of methane to offset 1 tonne of carbon dioxide under the GWP100 using GWPs from IPCC's Sixth Assessment Report, AR6 (IPCC, 2021). Thus, using GWP20 in offset systems would reduce rather than strengthen abatement incentives for methane.

The Canadian province of Alberta has opted to add an emission credit market to its GHG pricing regulation for large facilities (the Technology Innovation and Emission Reduction, TIER, regulation, further described in Section 4.1.4), called the Alberta Emission Offset System. Offsets may range in scope but must be quantified using Alberta-approved quantification protocols[45] for each type of project and verified by a third-party assurance provider in accordance with TIER's rules for validation, verification and audit, and offset projects (Alberta Ministry of Environment and Parks, 2019, 2020a). Offsets must be registered and publicly listed on the Alberta Emissions Offset Registry. Facilities already covered by TIER cannot generate Alberta emissions offsets. However, conventional oil and gas facilities designated as aggregate facilities[46] can generate offsets from their methane reduction through pneumatic devices and vent-gas reduction as vented gas is excluded from the calculation of an aggregate facility's total regulated emissions under TIER (Alberta Ministry of Environment and Parks, 2020b, 2021a). These offsets are converted into CO_2e using a GWP100 value of 25 (from IPCC, 2007).

4.1.4 Methane emission performance standards

Another policy instrument option available to policy makers is an emission performance standard. At its core, such a standard defines an emission intensity benchmark (i.e., the allowed average amount of emissions per unit of oil or gas produced) and allows producers freedom in terms of how they reach that benchmark or to pay penalties for any emissions above the benchmark.

Policy makers may choose this option to allow firms a certain level of emission intensity in their operations and to give them the flexibility around specific abatement decisions. In addition to the design choices outlined in Section 4.1.1, there are a few distinct elements of an emission performance standard that must be specified.

First, policy makers need to define the underlying emission intensity metric. While all methane emission intensity metrics define an amount of methane emitted per unit of production, there is no standard approach for which emissions or units to include in the numerator and which definition of production volume to include in the denominator. In general, policy makers should include all sources of methane emissions — including from venting and incomplete flaring, and fugitive emissions — in the numerator. This means methane emissions from both oil and gas

[45] See further the list of approved, flagged, and withdrawn quantification protocols, https://www.alberta.ca/alberta-emission-offset-system.aspx#jumplinks-2
[46] Small facilities with the same owner can come together as an "aggregate facility" and opt into the TIER.

production should be included and there should be no exceptions for specific emission sources. In contrast, there are several different options available for the choice of unit for the volume of production in the denominator (where the energy contents of production are also an alternative to volume). Marketed production volume is preferable to gross production volume because it is easier to verify. One option is to include both marketed oil and gas volumes in the denominator, while another is to include only marketed gas volumes (see, e.g., the OGCI definition discussed below). As long as the definition is clearly stated, the resulting emission intensity can be translated and compared with other intensity definitions.

Second, policy makers need to choose an emission intensity benchmark. In order to ensure emission reductions, this decision should account for the estimated baseline emission levels and any emission reductions that may result from other policies. It may be difficult initially to establish a sufficiently ambitious emission intensity benchmark, because absolute emission levels — the quantity of ultimate policy interest — will fluctuate with changes in overall production volumes. In effect, the benchmark - which provides firms a certain level of emissions for which they do not need to pay an emission price - is an implicit production subsidy and thereby encourages more oil and gas production (than if the benchmark were zero).[47] Policy makers should therefore design the intensity benchmark to ratchet down over time. This will help ensure continued emission reductions as policy makers' understanding of what constitutes a binding benchmark improves.

A common intensity benchmark and definition comes from the OGCI. This is a 0.2% intensity benchmark with intensity defined as total methane emissions volume divided by marketed volume of natural gas.[48] Based on available baseline emission intensity estimates (e.g., more than 2% in the U.S.; Alvarez et al., 2018), a 0.2% benchmark would likely be binding for the industry as a whole. This intensity definition is attractive for its transparency, its comprehensive coverage of methane emission sources, and its reliance on marketed gas volumes.

Third, regulators need to choose a penalty for regulated entities whose emissions are above the intensity target. This penalty should ideally be charged per tonne of methane emitted above the

[47] See also Fischer (2001) for a comparison of the abatement incentives and production subsidy effects with output-based rebating of environmental tax revenues or permit rents through tradable performance standards, an emission fee with rebates based on market share and an ETS with output-based permit allocation.
[48] Oil and Gas Climate Initiative Reporting Framework 3.3, October 2020, p. 15, https://www.ogci.com/wp-content/uploads/2020/10/OGCI-Reporting-Framework-3.3-October-2020.pdf

emissions intensity threshold (per unit of production) — i.e., essentially an emissions price. Considerations around the specific penalty level are the same as discussed for a methane emissions fee in Section 4.1.2.[49]

Fourth, policy makers may choose to make the performance standard tradable. In contrast to a traditional emission performance standard, which requires each company to either pay penalties or achieve the predefined emission intensity benchmark through its own mitigation activities, a tradable performance standard gives companies the option to comply by buying emission credits from other companies that have emissions below the benchmark. With a nontradable performance standard, the policy maker chooses the penalty level but does not control the resulting emission intensity achieved across the whole portfolio of regulated entities. In contrast, with a tradable performance standard the policy maker can choose the average emission intensity level that the whole portfolio of regulated entities must achieve. However, as with an ETS the policy maker does not control the emission price, which is instead determined through credit trade between the regulated entities. With a tradable performance standard, the emission price is often not observable – unless the regulator provides a trading platform for credits where that data is made available to the regulator (and ideally also researchers).

There are a few existing examples of emission performance standards covering methane emissions that have been implemented in practice. However, these policies do not specifically target methane emissions but rather multiple GHGs. Similar to the situation where methane is included in an ETS that also covers other GHGs (see Section 4.1.3), this design means that the GWP used to convert methane into CO_2e will be a determinant of the size of the methane mitigation incentive, as will the relative abatement cost compared to the other GHG sources covered by the policy.

The Canadian provinces of Alberta and Saskatchewan have implemented GHG emission pricing in the form of tradable performance standards.[50] Alberta's so-called TIER regulation covers

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[49] Penalties for not complying with the emission standard and exceeding the target could also be flat and not vary with emission levels, but those that are proportional to emissions provide much better incentives for abatement.
[50] Canadian provinces have been required to implement GHG emissions pricing and can enact their own carbon pricing legislation as long as this legislation meets the federal stringency benchmarks, established through either: (i) the federal fuel charge — a direct charge that reflects Canada's prevailing carbon price on 21 fossil fuels, including gasoline and natural gas; or (ii) the federal Output-Based Pricing System (OBPS), a performance-based trading system for large industrial emitters. Aimed at mitigating the competitiveness and carbon leakage risks associated with the federal fuel charge, the federal OBPS covers facilities that emit more than 50 kilotonnes CO_2e per year from industries, including oil and gas. However, methane emissions from venting and leakage from upstream, midstream, and downstream oil and gas facilities are not covered by the federal regulation.

large industrial emitters (above 100 kilotonnes of CO_2e per year). In Saskatchewan, the regulation instead covers facilities emitting above 20 kilotonnes of CO_2e. In both provinces, conventional oil and gas facilities emitting at least 10 kilotonnes of CO_2e per year can voluntarily opt in to their respective provincial trading systems. The incentive for doing so is that they are otherwise subject to federal regulation.

In both Alberta and Saskatchewan, the tradable performance standards cover not only methane but also other GHGs. Saskatchewan's tradable performance standard covers methane emissions only from venting and incomplete flaring (not fugitive emissions) from oil and gas production and processing facilities (Government of Canada, 2019). Meanwhile, under Alberta's TIER[51], facilities across the entire oil and gas supply chain are covered, and in their GHG MRV report they are required to include estimated methane emissions from venting and flaring, and fugitive emissions. These methane emissions are quantified using emission factors established by the authorities (Alberta Ministry of Environment and Parks, 2021b). To calculate a GHG emission intensity, methane emissions are converted into CO_2e using a GWP100 value of 25 (from IPCC, 2007).

Under Alberta's TIER, the GHG intensity benchmark for each facility can be either: (i) the average emissions of the 10% most emissions-efficient facilities producing the same product; or (ii) 10% reduction relative to the facility's historical emissions intensity. Facilities can choose the less stringent of these two approaches (Alberta Ministry of Environment and Parks, 2021c). In Saskatchewan, a benchmark for each facility is based on its three-year average emissions intensity performance (Environment and Climate Change Canada, 2021).

Facilities with estimated emission intensities lower than their benchmarks can earn surplus credits that they can sell or save for later use. Those that exceed their benchmarks must provide compensation for excess emissions by: (i) buying surplus credits from other facilities covered by the regulation; (ii) buying offset credits from the Alberta Emission Offset System (see Section 4.1.3);[52] or (iii) paying into the respective provincial technology funds — equal to the prevailing federal carbon price. The Canadian federal government adopted a carbon price of C$20

[51] The TIER Regulation replaced the Carbon Competitiveness Incentive Regulation (CCIR) in January 2020. The CCIR, effective in 2018 and 2019, replaced the Specified Gas Emitters Regulation which had been in place for ten years.

[52] This option is not yet available in Saskatchewan. In 2021, the Saskatchewan Ministry of Environment started to develop a provincial offset system.

(approximately US$15) per tonne of CO_2e as of April 1, 2019, rising by C$10 per tonne annually to C$50 (approximately US$39) as of April 1, 2022, and thereafter rising by C$15 per tonne annually to reach C$170 (approximately equivalent to US$130) in 2030.

Another example of an emission performance standard is Colorado's Greenhouse Gas Reporting and Emission Reduction Requirements (Regulation Number 22), adopted in 2021.[53] This establishes methane and other GHG emissions intensity targets for oil and gas well sites that will ratchet down over time. The intensity metric is defined as emissions (expressed in metric tonnes of CO_2e) divided by the annual production of hydrocarbon liquids and natural gas (expressed in energy content). The new regulation does not currently specify how emissions verification will be carried out.

Although still just a proposal, the methane fee included in the Build Back Better Act (also discussed in Section 4.1.2) is also structured as a (nontradable) emission performance standard.[54] In this proposal, onshore and offshore production facilities would pay a fee for every metric tonne of methane emitted over a 0.2% intensity benchmark (intensity is defined here using marketed gas only). Transmission and other non-production facilities sites would be held to lower emission intensity benchmarks of 0.11% and 0.05%, respectively.

4.2 Policy instrument options for oil- and gas-importing countries

For oil- and gas-importing regions, a large share of the methane emissions footprint related to their oil and gas consumption comes from upstream methane emissions in the oil- and gas-producing countries from which the commodities are imported. Addressing these upstream footprint emissions is challenging because the importing country typically does not have direct jurisdiction over the oil and gas producers that are responsible for the emissions and for exporting the commodities to their markets. The point of obligation for any policy instrument to address footprint emissions will typically therefore need to be entities on the importing (or buyer side) that are subject to the importing country's jurisdiction. In addition, the policy instrument also needs to be designed to account for the challenges in ensuring robust MRV for the emissions associated with imports and arising outside the country's borders, as discussed in

[53] https://cdphe.colorado.gov/aqcc-regulations
[54] See https://www.congress.gov/bill/117th-congress/house-bill/5376/text

Section 3.3. In this section, we outline the main policy instrument options available to oil- and gas-importing countries for addressing upstream footprint emissions.

4.2.1 Regulatory equivalence for imports

A region that relies heavily on imports for a large share of its oil and gas will in some cases have its own small oil- and gas-producing sector. This is the case, for example, in the EU, where some oil and gas production exists in member countries such as Denmark, the Netherlands, and Romania. As EU policy makers are now considering introducing work practice standards such as LDAR and restrictions on venting and flaring for all oil and gas supply chain segments located inside EU member countries (see Section 2), they also have the option to cover footprint emissions by requiring that imported oil and gas be produced with equivalent work practice standards.[55] In theory, the most straightforward way to ensure this is the case is by requiring that oil and gas are imported only from regions that have the same or more stringent regulations in place. Strictly speaking, this is not a policy instrument based on methane MRV but is included here for completeness.

4.2.2 Methane procurement (or portfolio) standards

A buyer-side version of the methane performance standard discussed in Section 4.1.4 is a methane procurement (or portfolio) standard.[56] Such a procurement standard for oil and gas could take the form of a requirement that all (or a certain share of) the oil and gas sold on the domestic market needs to meet a specific methane emission intensity benchmark. For natural gas this benchmark could, for example, be the established methane emission intensity definition and threshold of 0.2% from the OGCI.[57]

The point of obligation for such a procurement standard could be major oil- and gas-buying entities, including wholesalers, large industrial buyers, and gas distribution companies. These would be required to hold certificates for oil and gas verifying that they have been produced with

[55] There are potential constraints related to World Trade Organization agreements that limit the ability of importing countries to put restrictions on production practices for imports. A discussion of these legal considerations with respect to international trade law is beyond the scope of this paper.
[56] This type of instrument may also be referred to as a methane performance standard or a methane emission standard (see, e.g., Mohlin et al., 2021). Here, we use the term “procurement standard” to describe an instrument with the point of obligation on the buyer’s side and to distinguish it from the methane performance standard described in Section 4.1.4. For the latter, the point of obligation is the emitting entities on the producer side.
[57] Oil and Gas Climate Initiative Reporting Framework 3.3, October 2020, p. 15, https://www.ogci.com/wp-content/uploads/2020/10/OGCI-Reporting-Framework-3.3-October-2020.pdf

methane emissions below the specified emission intensity benchmark and covering a certain share of their oil and/or gas purchase volumes (or even 100% of their purchase volumes).

A prerequisite for this approach is an established system for robust low methane gas certification, as discussed in Section 3.3. An advantage of relying on a certificate system from the perspective of an oil- and gas-importing country is that certificates could be issued for oil and gas produced domestically as well as in other countries, thereby addressing some of the MRV challenges for footprint emissions discussed in Section 3.3.

The environmental effectiveness of this instrument would rely both on the extent of coverage of the portfolio standard (i.e., the size of the oil and gas portfolio share that is required to be covered by certified oil and gas), the robustness of the certification system, and the selection effect associated with certification (see Section 3.3), as well as the leakage effects propagated through the global oil and gas markets (see Section 4.2.4).

A related real-world example is the California Low Carbon Fuel Standard (LCFS). While the LCFS does not specifically target methane emissions, this instrument is designed to reduce the GHG footprint of transportation fuels in the California market. It does so by defining a declining GHG emission intensity benchmark that needs to be met on average across the whole portfolio of domestically produced and imported transportation fuels. The LCFS then allows entities trading fuels with lower GHG intensity than the benchmark (e.g., biofuels) to sell credits to entities trading fuels with higher GHG intensity than the benchmark (e.g., petroleum fuel oils).

This emission credit design in the LCFS is similar to the tradable emission performance standard described in Section 4.1.4, with the important difference being that here the point of obligation is not the emitting upstream entities themselves. Instead, the point of obligation for the LCFS is entities on the buyer's side: petroleum importers, refiners, and wholesalers. When transportation fuels are imported, refined, or sold in California, the entities regulated under the LCFS enter information for each transaction into a central data system. This LCFS central reporting tool tracks the corresponding emission credit or deficit position relative to the target emission intensity for each transaction of fuel and sums the position for each regulated entity. Credits are then retired when they are used to cover deficits in the annual compliance period (Boutwell, 2017).

Instead of relying on a certification system, the LCFS uses a tool called the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) to assess the GHG footprint of imported petroleum fuels (El-Houjeiri, 2018). OPGEE provides GHG footprint estimates that vary depending on the production area from which the fuel is imported. This GHG footprint estimate for petroleum fuels is then used to calculate the difference between the fuel's emission intensity and the LCFS emission intensity benchmark. This then creates an obligation on the importer or refiner of the fuel to pay for emission credits to cover the difference for the whole volume of traded fuel. In effect, the use of the OPGEE tool means that the LCFS does not rely on an MRV system. So while this approach increases the price of fuels with high footprint emissions, it does not provide an abatement incentive to oil and gas producers because there is no direct way for them to reduce the OPGEE footprint estimate assigned to their fuel. To improve the abatement incentives, one possibility would be to allow for the option to certify fuels with a lower emissions intensity than the one estimated with OPGEE. This incentive would, however, also be muted by the option for producers to sell their fuels to other markets with no such instrument in place, as discussed further in Section 4.2.4.

4.2.3 Methane border adjustments

Countries that choose to cover their domestic methane emissions from the oil and gas sector through a methane emissions fee or inclusion in an ETS (see Section 4.1) also have the option to extend this emission pricing to their oil and gas imports by introducing an emission border adjustment. For the great majority of countries that are members of the World Trade Organization (WTO), the border adjustment would need to mirror the methane price imposed on domestic entities in order to comply with WTO agreements (see, e.g, Cosbey et al., 2020, for further discussion).

The border adjustment for a methane fee could be a charge applied to imported oil and gas, to be paid by the importer when the commodity enters the country. The charge should reflect the price of methane already applied domestically in the country. With an ETS, oil and gas importers could instead be required to purchase emission allowances to cover the estimated methane footprint associated with their purchased oil and gas volumes.

The methane footprint per unit of purchased oil or gas could be determined using a default emission estimate methodology. To provide an abatement incentive, there should ideally also be an option to certify a methane intensity lower than the default estimate using a scientifically robust MRV methodology aligned with OGMP 2.0 Level 5. If the imported gas (or oil) is certified to have been produced with a lower emission intensity than the default emission intensity, the number of allowances per unit of gas (or petroleum product) that the importer would be required to hold (or the amount of methane charges levied) would be proportionally reduced.

Border adjustments for GHG emissions have not yet been implemented anywhere in the world and are the subject of ongoing political and academic discussions concerning international trade law and global equity considerations. The EC has proposed a Carbon Border Adjustment Mechanism (CBAM), which would cover carbon dioxide, nitrous oxide, and perfluorocarbon emissions from selected emission-intensive sectors already regulated under the EU ETS (European Commission, 2021b). Under the proposal, importers would have to buy a sufficient number of certificates to cover the embodied emissions in the goods they import. The price of the certificates will be based on the weekly average auction price of EU ETS allowances. The EU CBAM proposal has been designed to be compliant with WTO agreements and rules. However, its actual implementation will determine this compatibility, particularly regarding the double nondiscrimination test: nondiscrimination between domestic and foreign suppliers, and nondiscrimination between foreign suppliers (Sapir, 2021). Because the EU ETS does not cover energy sector methane emissions, it has not been an option to include methane in the current CBAM proposal.

In June 2022, a proposal on a carbon border adjustment, the Clean Competition Act, was proposed in the US Senate. The import tariff is to be levied on carbon-intensive goods including fossil fuels from 2024. The levy would be calculated based on the ratio of: (i) either the country of origin's economy-wide carbon intensity to the U.S. economy-wide carbon intensity; (ii) or the relevant industry-specific average carbon intensity to the comparable U.S. industry-specific average carbon intensity. Foreign manufacturers would also be able to petition to use their own firm-level carbon intensities. Importers would only pay the levy based on the fraction of emissions that exceeds the comparable U.S. carbon intensity. Similarly, American domestic providers whose carbon intensity is above the applicable industry-specific carbon intensity baseline would pay the levy on the fraction of emissions that exceeds the industry average carbon intensity. The applicable U.S. carbon intensity baselines would be reduced by 2.5 percentage points annually from 2025-2028 and then starting in 2029 decline by 5 percentage points annually until reaching net zero in 2046. The levy would begin at $55 per tonne of CO_2e and increase at 5 percent real per year. Notably in this bill, the quantity of methane is converted to CO_2e using the 20-year GWP, while the conversion of other GHGs uses the 100-year GWP. In calculating the levies for domestic providers the US Treasury will use the GHG reporting program (GHGRP) which suggests that methane emissions that are reported in the GHGRP will be covered by the levy (US Congress, 2022). For the oil and gas sector, research has however shown that the US GHG inventory significantly underestimates US methane emissions – particularly from high emissions events caused by abnormal operating conditions (see Alvarez et al, 2018).

4.2.4 Pass-through of emission penalties and emission leakage in the global oil and gas markets

For all of the importer (or buyer-side) policy instrument options discussed in this section, there are two aspects that are particularly relevant for assessing their potential mitigation impacts. The first of these is the extent to which the buyer-side entities that are subject to the emission penalties under these instruments can pass through those penalties to their oil and gas suppliers. A condition for the policy instrument to provide abatement incentives for the upstream oil and gas producers is that the buyer-side entity in its contractual agreement(s) is able to pass through any penalties, fees, or payments associated with the policy instrument to the upstream companies. The extent to which a methane penalty or fee can be passed through further upstream (rather than being incurred by the buyer-side entity itself or passed through further downstream to end users) depends on the relative bargaining power of the buyers versus the suppliers (and their respective counterparties further upstream and downstream). If, for example, a gas buyer cannot threaten to switch to another upstream supplier when negotiating contracts because the market is concentrated with just a few large suppliers, then the buyer's ability to pass through the cost of any emission penalties further upstream may be more limited. In turn, this will mute the abatement price signal for the upstream gas producers.

The second, and closely related, aspect is the global nature of the oil and gas markets. If one country on its own implements a buyer-side policy that puts restrictions on the methane emissions footprint of its oil and gas imports, oil and gas suppliers have the option to start shipping these commodities to other markets that lack such restrictions. A buyer-side approach is therefore more likely to be effective when more countries put in place similar restrictions. A large club of countries demanding oil and gas imports with low methane emissions would be able to apply more pressure on oil and gas producers, as well as on oil- and gas-producing countries to put in place policies to address their methane emissions (for example, by implementing any of the policy instruments for addressing domestic emissions outlined in Section 4.1).

In an ongoing research project, we are using the Global Gas Model developed at the Norwegian University of Science and Technology and the German Institute for Economic Research (DIW Berlin) to look at the impacts on the global gas market of different coalitions of countries putting in place methane emission restrictions on their gas imports.

5. Addressing mid- and downstream emissions: regulatory options for gas transmission and distribution

Methane leaks from the gas transmission and distribution segments are the responsibility of pipeline companies and gas utilities — also known as gas transmission and distribution system operators, respectively. These entities are regulated companies that need approval from their energy market regulator to incur costs and recover them from their customers. This arrangement also affects these operators' incentives to address methane emissions from their facilities, and means that regulator can change the operators' incentives to address methane leaks by changing both the regulatory requirements on their operations as well as the rules for their cost recovery.

In terms of regulatory requirements, regulators can address methane emissions from these segments by requiring more frequent and advanced LDAR,[58] restricting venting and flaring practices (as appropriate for safe operations in the specific segment), and requiring upgrading to low- or zero-emitting equipment for relevant infrastructure components as also discussed in Section 2.

For example, in the U.S., existing regulations require transmission and distribution operators to conduct LDAR inspections (Strange et al., 2022). These inspections have traditionally been carried out via such methods as internal installations referred to as mass balance systems, which monitor and check for disparities between gas flows at different points within the pipeline. Visual or, in the case of the distribution system where gas is odorized, olfactory inspections are also common detection approaches in these sectors. However, recent evidence indicates that such traditional approaches may miss a significant portion of pipeline leaks (Weller et al., 2018). Just as is the case for upstream segments, advanced leak detection technologies and data analytics (referred to as ALD+) methods are increasingly available and offer less labor-intensive tools that directly seek out methane leaks. For example, unmanned aerial vehicles, fiber-optic cables, and even satellites can augment existing detection methods by pinpointing smaller departures from local background methane concentrations. Coupling these data with analytics to pinpoint issues such as leak flow rates and locations makes it easier to prioritize abatement

[58] System operators are typically already required to perform LDAR, but with a focus on preventing leaks that are sufficiently large to be considered a safety hazard.

efforts (Weller et al., 2019). However, as pipeline networks are vast and many leaks are quite small relative to even advanced technology detection limits, operators often need to rely on multiple, sometimes overlapping, methods to ensure the greatest chances of detection. Regulators can therefore leverage these technological advancements and require that system operators conduct ALD+ programs. Examples of such programs are growing and include transmission companies, e.g., Enbridge's reliance on multiple redundant detection systems (Enbridge, 2020); and utility companies, e.g., the use of mobile ground labs by California's PG&E (PG&E, 2021) and Alberta's ATCO's (ATCO, 2021) to detect both small and large emissions events.

Furthermore, going back to the incentives for these revenue-regulated companies, a common regulatory practice is to allow gas transmission and distribution companies to pass the cost of gas that is lost and unaccounted for onto their customers. This practice limits these companies' incentives to address non-hazardous methane leaks because the cost of any gas lost to the atmosphere can often be fully covered from their customers.[59]

Mass balance systems, or similar approaches to estimate the amount of gas lost from the system, may not necessarily provide an accurate read of methane emissions (e.g., due to low metering frequency, meter quality, and gas being used as fuel for compressor stations). However, this estimated difference between gas received and delivered provides a reference data point that can be used in assessing the amount of methane leaked from the relevant system.[60] The regulator can then use this to improve the operator's incentive to address leaks.

Specifically, regulators can improve system operators' incentives for methane management by stipulating a benchmark for unavoidable gas losses (e.g., 0.1% of gas volume delivered) and allowing cost recovery only up to that level. Although the specific loss benchmark will still allow for some losses and associated emissions, the key element of this approach is the restriction on cost recovery. By limiting how much of their losses operators can pass through to customers, such regulations incentivize them to improve their methane management practices and reduce gas losses on their system down to the stipulated loss benchmark such that they avoid incurring

[59] For further discussion on this, see Hausman and Muehlenbachs (2019).
[60] For this metric to be of sufficiently good quality and with uncertainty ranges that are not too large, better or additional meters may need to be installed at the entry and exit points of the system.

the cost of excessive gas losses themselves.[61] In this case, the size of the incentive to avoid gas losses above the benchmark is given by the price of natural gas facing the operator. This incentive can be further strengthened if the operator is also required to pay a methane emission fee (or buy emission allowances) for any gas lost on its system and is allowed to pass through only the portion of those compliance costs that corresponds to the stipulated benchmark.

Another option for reducing emissions in the gas distribution and transmission segments is to invest in infrastructure replacement, such as pipeline replacement programs. However, regulators need to be careful in approving such costly capital investments without in-depth analysis. Pipeline replacement programs are not necessarily good long-term investments, given that decarbonization of the energy system requires large-scale electrification of residential and commercial heating. Approval of such investments should therefore be given only if the company can show that pipeline replacement is a reasonable investment motivated by safety and environmental benefits that outweigh any stranded asset risk from decarbonization and potential decommissioning.

As with addressing footprint emissions related to production and processing, addressing methane leakage from gas transmission systems outside a country's own borders is more complicated because the country's own regulatory agency does not have authority to monitor or regulate methane leakage from those gas transit systems. If the required metering is in place and contracts for gas deliveries to the border are (or can be) specified such that the downstream gas-buying entity pays only for the quantity of gas delivered to their border, and not for controllable gas losses that occur in transit, there would be some incentive for gas transit and gas production countries to limit the gas lost on their part of the transmission system before it reaches their border. However, the size of that incentive would be determined by the market value of the gas being shipped. To address methane emissions in gas transit countries with leaky pipelines, it will be important to leverage whatever external pressure new satellite monitoring data and buyer-side actors can create to incentivize these countries and their operators to address leaks from their pipeline systems. Similar issues also arise with emissions from LNG shipping, where contract terms for gas losses during transportation may influence the shipping entities' incentives to address them.

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[61] See, e.g., Council of European Energy Regulators (2020) for further discussion on the metering/measurement issues and current regulatory approaches for the gas "delta in-out" in European countries for the distribution segment.

6. Outstanding research questions

In this paper, we explore different policy instrument options to address methane emissions across the oil and gas supply chain. Recent advances in measurement technologies and practices have improved our understanding of the scale and sources of these emissions, and new and more detailed data are continously being generated. New data at more granular levels will enable researchers to carry out more empirical analysis of the potential impacts of these different policy instrument options, in terms of impacts both on methane emissions and on the oil and gas markets, as well as on end users and the related distributional impacts in different countries and regions.

Many outstanding questions remain for further research and analysis. These include:

(1) What are the barriers to adoption of methane abatement technologies and approaches in the oil and gas industry? How do these barriers differ across the oil versus gas segments and upstream versus midstream and downstream segments? Related to this, what do marginal abatement cost curves look like when estimated using methane measurement data and real-world observations on company decisions?

(2) What have been the methane emission impacts of regulations such as LDAR and restrictions on venting and flaring in different jurisdictions where these regulations have already been implemented? Having methane measurement data before and after implementation and from comparable jurisdictions with and without these types of regulations will enable researchers to enhance previous findings on the effectiveness of these types of regulations.

(3) How effectively have existing policies and regulations for addressing methane emissions been implemented, monitored, and enforced in different jurisdictions? How can capacity-building efforts target any identified gaps in existing monitoring and enforcement approaches?

(4) What are potential opportunties for firms to misreport under MRV regulations? Under policies that price methane emissions, firms will have an incentive to look for loopholes. What are potential gaps in MRV systems or perverse incentives in the design of MRV regulations, and what are approaches for addressing them? How could policy be designed to handle MRV-related disputes? For example, how could parties resolve a situation where remote sensing at the regional level does not match the bottom-up measurements from MRV, or where an exporting

country asserts MRV of emissions that the importing country refuses to accept as sufficiently robust?

(5) Are there trade-offs in allocating effort to avoid super-emitting events versus managing everyday leaks? Could mechanisms such as escalating penalties for large emitting events or repeated super-emitting detections be designed to find a balance in incentives for addressing these different categories?

(6) What is the estimated methane emission impact of MRV-based policy instruments such as methane emission pricing or emission performance standards in different oil- and gas-producing countries? How do these emission impacts compare to those achieved with direct regulations that do not rely on emissions quantification?

(7) What is the impact on methane emissions of a methane procurement standard implemented in different oil- and gas-importing countries?

(8) How does the choice of GWP for methane influence the mitigation incentives to address methane relative to other GHGs under an ETS compared to tradable and nontradable performance standards or an emissions fee when the instruments also cover GHGs other than methane? How could the choice of conversion rate be corrected to adjust for the uncertainty in reported methane emissions and the associated probability of non-detected methane emissions?

(9) What is the incidence of different policy instrument options? How are the compliance costs of these regulations distributed across different market actors? What is the ultimate impact on end users' energy bills of different policy instrument options?

(10) What are the environmental justice implications in terms of local air pollution and employment impacts of different policy instrument options in different local, regional and national jurisdictions?

(11) How do joint-venture contracts and production-sharing agreements affect incentives to address methane emissions and how would these interact with, or be influenced by, different policy instrument options? Which instruments are more likely to be effective for addressing methane emissions from assets with coproduction of oil and gas?

(12) How do long-term contract terms in the LNG market impact the possibilities to pass through any methane emission penalties applied to the buyer's side to upstream suppliers and producers?

(13) What are the potential impacts on global methane emissions of the emerging market for natural gas certified to have low methane emissions? How robust are the certification programs used and how large are the leakage effects propagated through the global market for natural gas?

7. Conclusions

Policy makers looking to address methane emissions from the oil and gas sectors have a range of regulatory and policy instrument options at their disposal. In this paper we first describe the tried and tested regulatory approaches that have already been implemented in several jurisdictions to address methane emissions. These include work practice standards such as frequent LDAR and restrictions on venting and flaring, as well as technology standards requiring the installation of equipment with low emissions. These regulatory approaches can be implemented in the upstream oil and gas segment, as well as the mid- and downstream gas segments. Such work practice and technology standards can provide an important backstop by ensuring mitigation efforts occur at every site and that local air pollution affecting nearby communities is reduced — even if additional, quantification-based policy instruments are also implemented.

We also describe the key features of methane MRV regulations. Such regulations require the collection of emissions data that improve industry actors' knowledge of their own emissions and mitigation opportunities, and would also improve aggregate data on a country's methane emission levels. Furthermore, MRV regulations lay the groundwork for the implementation of policy instruments based on methane emissions quantification. A robust MRV regulation is based on methane measurements and requires representative sampling at different scales, from on-the-ground bottom-up measurements, all the way up to site-level measurements in line with the OGMP 2.0 framework. Importantly, verification of reported emissions should leverage aerial and remote sensing data, including from satellites, to corroborate company-reported emissions data using observations at the regional scale and from high-emission events.

Lastly, we cover the main policy instrument options that could be implemented to ensure policy makers reach their stated methane and GHG emission targets. In oil- and gas-producing countries, policy makers have a range of options for addressing methane emissions from the upstream segment of the oil and gas supply chain. These are all different approaches for pricing methane emissions and include a methane emissions fee (or tax/charge), inclusion in an ETS, or a methane emission performance standard.

In oil- and gas-importing countries, the options for addressing imported footprint emissions from the upstream segment include regulatory equivalence (i.e., requiring that imports meet the same work practice standards as oil and gas produced domestically), a methane procurement standard imposed on oil and gas buyers, and methane border adjustments. These options all need to take into account international trade law considerations and will typically require that, as a minimum, the same or more stringent regulations have already been implemented on any domestic oil and gas production. While oil- and gas-importing countries are more limited in their ability to monitor and enforce regulations for footprint emissions, implementing any of these options would put pressure on oil- and gas-producing companies, as well as oil- and gas-producing countries, to address their methane emissions.

This paper has focused on the design features of different policy and regulatory options. Regardless of which option(s) is ultimately chosen, effective monitoring and enforcement are essential to ensure the chosen option's methane-reduction potential is realized. Capacity-building — particularly in developing countries — is required to make sure the relevant regulatory agencies have the resources and know-how of methane emissions and their sources to be able to effectively monitor and enforce the regulations once they have been adopted.

Finally, the IEA's (2021b) methane regulatory roadmap provides a step-by-step guide for regulators detailing how to gather the information they need to design, draft, and implement effective policy instruments and regulations to address methane emissions in their jurisdiction.

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