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Final report

Pricing supply chain emissions of natural gas

Options for their inclusion in the EU ETS 1 and Carbon Border Adjustment Mechanism (CBAM)

by:

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Abstract: Pricing supply chain emissions of natural gas

This report assesses the relevance of natural gas supply chain emissions as well as options for their regulation and pricing within the EU climate policy framework. Including direct supply chain emissions – both CO₂ and methane (CH₄) – can significantly increase the estimated total climate impact of natural gas, raising the overall climate footprint of natural gas by up to 35% compared to considering combustion emissions alone.

Unregulated supply chain emissions risk distorting the path towards climate neutrality by artificially distorting the competitiveness of natural gas, both in a direct comparison to low-carbon alternatives as well as in downstream markets like the one for hydrogen. In this context, grey and blue hydrogen could benefit from an unlevel playing field over the production of green hydrogen.

Currently, a large share of natural gas supply chain emissions emitted within the European Economic Area (EEA) is already subject to regulation. CO₂ emissions at stationary installations along the natural gas extraction, processing, pipeline transmission and potential liquefaction segments of the supply chain are priced under the European Emissions Trading System 1 (EU ETS 1). CO₂ emissions from LNG shipping are also (partially) included under the EU ETS 1. Methane emissions monitoring along all supply chain segments is advancing through the EU Methane Regulation, which will demand Oil and Gas Methane Partnership (OGMP) 2.0 Level 5 equivalent MRV for all assets in the EEA by the end of this decade.

However, emissions occurring outside the EEA, where a large share of natural gas consumed in the EU originates, remain largely unregulated, despite accounting for a major portion of total supply chain emissions. The EU Methane Regulation aims to partially address this regulatory gap, while the Low-Carbon Fuels Delegated Act provides some estimates to quantify these extra-EEA supply chain emissions.

Internationally, few gas-producing countries have implemented methane pricing or robust regulation of supply chain emissions. Norway and Australia focus on upstream emissions, with Norway combining CO₂ and CH₄ pricing and Australia applying a baseline-and-credit system. The U.S. had introduced a federal methane tax in 2024, which was repealed in early 2025. Canada has strengthened methane rules and proposed a sectoral cap-and-trade system, though its future is uncertain. In all cases, regulation is limited to production, lacks Oil and Gas Methane Partnership (OGMP) 2.0 Level 5 MRV standards, and faces political resistance.

This report outlines how an extension of the EU ETS 1 scope to natural gas supply chain emissions could look like, particularly with respect to methane emissions, and focuses on the associated opportunities and risks. However, in doing so, it does not aim to assess other potential alternative instruments and thus does not aim to provide conclusive policy advice or definitive proposals. The conclusions indicate that extending emissions pricing under the EU ETS 1 to the full supply chain of natural gas consumed in Europe would yield climate benefits but entails challenges. For CO₂, extension of the EU Carbon Border Adjustment Mechanism (CBAM) to reflect an analogous inclusion as under the EU ETS 1 appears feasible, although an MRV system for producers in third countries would need to be introduced. However, including methane emissions in the EU ETS 1 faces significant challenges, especially due to the risk of high MRV uncertainty in a system relying on precise emission estimates. A cautious approach would be to first build up experience with the implementation of the Methane Regulation before evaluating its suitability for providing the basis of an inclusion in the EU ETS 1. An inclusion of EEA methane supply chain emissions in the EU ETS 1 would be a prerequisite to any analogous extension of the CBAM.

Kurzbeschreibung: Bepreisung von Erdgas-Vorkettenemissionen

Dieser Bericht untersucht die Relevanz von Emissionen entlang der Erdgas-Wertschöpfungskette sowie Optionen für deren Regulierung und Bepreisung im Rahmen der europäischen Klimapolitik. Der Einbezug direkte Emissionen aus der Lieferkette – sowohl Kohlendioxid (CO₂) als auch Methan (CH₄) – kann die Abschätzung des gesamten Klimafußabdrucks von Erdgas erheblich größer ausfallen lassen - um bis zu 35 % mehr als bei reiner Berücksichtigung von direkten Verbrennungsemissionen .

Unregulierte Emissionen entlang der Lieferkette bergen das Risiko, die Entwicklung zur Klimaneutralität zu verzerren, indem sie die Wettbewerbsfähigkeit von Erdgas gegenüber emissionsarmen Alternativen künstlich verbessern – sowohl im direkten Vergleich als auch in nachgelagerten Märkten wie dem Wasserstoffsektor. Insbesondere könnten grauer und blauer Wasserstoff dadurch einen strukturellen Vorteil gegenüber der Herstellung von grünem Wasserstoff erlangen.

Innerhalb des Europäischen Wirtschaftsraums (EWR) unterliegt bereits ein erheblicher Teil der Emissionen entlang der Erdgas-Lieferkette einer Regulierung. CO₂-Emissionen aus stationären Anlagen in den Segmenten Förderung, Aufbereitung, Pipeline-Transport sowie potenzieller Verflüssigung werden im Rahmen des Europäischen Emissionshandels 1 (EU-ETS 1) bepreist. Auch CO₂-Emissionen aus dem LNG-Seeverkehr sind (zum Teil) in das EU-ETS 1 einbezogen. Das Monitoring von Methanemissionen entlang sämtlicher Lieferkettensegmente wird über die EU-Methanverordnung vorangetrieben. Diese schreibt bis Ende des Jahrzehnts ein MRV-System nach OGMP 2.0 Level 5 für alle Anlagen im EWR vor.

Emissionen außerhalb des EWR, woher ein großer Teil des in der EU genutzten Erdgases stammt, bleiben dagegen weitgehend unreguliert, obwohl sie einen erheblichen Anteil an den Gesamtemissionen der Lieferkette ausmachen. Die EU-Methanverordnung adressiert diese Regelungslücke teilweise, während die Delegierte Verordnung zu erneuerbaren und CO₂-armen Brennstoffen erste Ansätze zur Quantifizierung solcher extra-EWR-Emissionen bereitstellt.

International verfügen bislang nur wenige erdgasfördernde Staaten über eine Bepreisung oder strenge Regulierung von Lieferkettenemissionen. Norwegen und Australien konzentrieren sich auf Upstream-Emissionen, wobei Norwegen CO₂- und CH₄-Bepreisung kombiniert und Australien ein Baseline-und-Credit-System anwendet. In den USA wurde 2024 eine bundesweite Methanabgabe eingeführt, die jedoch Anfang 2025 wieder aufgehoben wurde. Kanada hat seine Methanregeln verschärft und ein sektorspezifisches Emissionshandelssystem vorgeschlagen, dessen Zukunft jedoch ungewiss ist. In allen Fällen beschränkt sich die Regulierung auf die Produktion, erfüllt nicht die Oil and Gas Methane Partnership (OGMP) 2.0 Level 5 MRV-Standards und stößt auf politische Widerstände.

Der vorliegende Bericht skizziert, wie eine Ausweitung des Geltungsbereichs des EU-ETS 1 auf Emissionen aus der Erdgasversorgungskette aussehen könnte, insbesondere im Hinblick auf Methanemissionen, und welche Chancen und Risiken damit verknüpft wären. Alternative Instrumente werden im Rahmen der Studie nicht untersucht, welche daher auch keine abschließenden politischen Empfehlungen oder Vorschläge formuliert. Der Bericht kommt zu dem Schluss, dass eine Ausweitung der Emissionsbepreisung auf die gesamte Erdgas-Lieferkette für in Europa verbrauchtes Erdgas mithilfe des EU-ETS 1 zwar erhebliche Klimavorteile bieten würde, jedoch auch Herausforderungen mit sich bringt. Für CO₂ erscheint eine parallele Erweiterung des EU CO₂-Grenzausgleichsmechanismus (CBAM) zur Einbeziehung wie im EU-ETS 1 grundsätzlich machbar, wenngleich hierfür ein MRV-System für Drittstaaten etabliert werden müsste. Die Einbeziehung von Methanemissionen in das EU-ETS 1 ist dagegen mit erheblichen Schwierigkeiten verbunden, insbesondere aufgrund der hohen MRV-Unsicherheit

bei der Erfassung präziser Emissionswerte. Ein vorsichtiges Vorgehen bestünde darin, zunächst Erfahrungen mit der Umsetzung der EU-Methanverordnung zu sammeln und anschließend deren Eignung als Grundlage für eine Einbeziehung in das EU-ETS 1 zu prüfen. Eine Integration der Methanemissionen aus der Lieferkette innerhalb des EWR in das EU-ETS 1 wäre dabei Voraussetzung für jede analoge Erweiterung des CBAM.

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List of abbreviations

Abbreviation	Explanation
bcm	Billion cubic meters
BOG	Boil-off gas
CBAM	Carbon border adjustment mechanism
CCS	Carbon capture and storage
CH₄	Methane
CO₂	Carbon dioxide
EEA	European Economic Area
EPA	US Environmental Protection Agency
EU	European Union
EU ETS 1	EU Emissions Trading System for Emission Intensive Industry and Energy, Aviation and Maritime Transport
EU ETS 2	EU Emissions Trading System for the sectors transport, buildings and small industry
EUTL	European Union Transaction Log
FSRU	Floating storage and regasification unit
GHG	Greenhouse gas
GWP	Global warming potential
LDAR	Leak detection and repair
LNG	Liquefied natural gas
MERP	US Methane Emissions Reduction Action Plan
N₂O	Nitrous oxide
NOK	Norwegian Kronor
OBPS	Canadian Output-Based Pricing System
OGMP	Oil and Gas Methane Partnership
MRV	Quantification, monitoring, reporting and verification (of emissions)
Sm³	Standard cubic meter
t	(Metric) tonne
UN	United Nations
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
WTO	World Trade Organisation

1 Introduction

The consideration of supply chain emissions is crucial in evaluating the overall climate impact of natural gas deliveries. These emissions, which include both carbon dioxide (CO₂) and methane (CH₄) emissions at all stages of the supply chain, can significantly increase the greenhouse gas (GHG) footprint of natural gas compared to only considering its combustion and therefore significantly lessen its climate advantage. In the context of stringent climate policies aimed at achieving climate neutrality, addressing supply chain emissions of natural gas is vital to ensure it remains a viable transition fuel. In addition, given the strong climate impact of methane and the important role it plays in natural gas supply chain emissions, policies targeting these emissions could be important levers in limiting short-term global temperature increases. However, without comprehensive measures to monitor and mitigate these emissions, supply chain emissions of natural gas could undermine national and international climate targets.

The problem of supply chain emissions of natural gas also impacts downstream markets and becomes particularly relevant in the context of the hydrogen economy. A climate-neutral economy will rely on green hydrogen for sectors and processes with difficult electrification prospects. However, during the transition phase, green hydrogen will have to compete with blue hydrogen, produced from natural gas with subsequent carbon capture and storage (CCS). Blue hydrogen's reliance on natural gas subjects it to the same challenges related to supply chain emissions of both CO₂ and methane. From a climate policy perspective, a level playing field between blue hydrogen and green hydrogen can only be achieved by fully accounting for and pricing the supply chain emissions of the natural gas used for blue hydrogen production.

The aim of this report is to explore possibilities for the European Union (EU) to price supply chain emissions of natural gas occurring both within and outside its borders. A range of additional (non-price) instruments exists to address supply chain emissions, but they are not the focus of this report and are only included insofar as they might be used to implement emissions pricing instruments. As a first step, Chapter 2 sets the ground by defining the different stages of the natural gas supply chain and providing estimates of the contributions of these stages towards total supply chain emissions. Next, Chapter 3 provides an overview of current regulation regarding supply chain emissions occurring inside the European Economic Area (EEA), from shipping, and outside the EEA. In order to set the European regulatory framework in context, Chapter 4 provides an overview of regulations targeting supply chain natural gas emissions in non-EU countries. Chapter 5 discusses options to regulate supply chain emissions occurring in Europe under the EU ETS 1, while Chapter 6 examines possibilities to cover supply chain emissions outside the EEA under the carbon border adjustment mechanism (CBAM). Chapter 7 addresses implications from supply chain emissions pricing, and Chapter 8 concludes.

Three final considerations are worth mentioning. First, the EEA imports a large share of the natural gas consumed within its borders. This should be considered when evaluating the different pricing instruments targeting emissions inside and outside the EEA. Second, this report focuses on supply chain emissions in the natural gas supply chain, because of its role as a transition fuel and the fact that natural gas constitutes the main driver behind supply chain emissions of blue hydrogen. Since very similar regulatory frameworks are applied in both the natural gas and oil sectors, this report briefly touches upon the option of pricing supply chain emissions of oil in addition to natural gas in Appendix A.1. Finally, the report only focuses on CO₂ and methane emissions. Even though other GHGs like N₂O are also emitted along the supply chain, their role is deemed negligible.

2 Supply chain emissions of natural gas

In this chapter, we first present a stylised overview of the supply chain of natural gas, highlighting the type of emissions and facilities involved at each stage (Section 2.1). It is important to highlight that we do not aim for a full life-cycle emissions assessment in this context. In contrast, we follow the literature and focus on CO₂ emissions from fossil fuel combustion and intended or unintended methane emissions along the supply chain. We disregard emissions occurring prior to natural gas extraction (e.g. during the exploration and well construction phase), indirect emissions (e.g. through electricity consumption or the commute of the workforce) and emissions embodied in the equipment used at the different stages. In a second step, we provide an overview of the latest estimates on the contribution of the different supply chain segments to total supply chain emissions (Section 2.2). This information is relevant when discussing the type of policy instrument to regulate supply chain emissions, as well as the relative importance of regulating the different segments of the supply chain (Chapter 3 and following).

Figure 1 Natural gas supply chain overview



Source: Own representation

2.1 Production stages in the natural gas supply chain

This section describes the different stages of the natural gas supply chain, including the processes involved, their emission intensity, as well as the main drivers based on recent publications (Wachsmuth et al. 2019, Baumann & Schuller 2021, Münter & Liebich 2023). To clarify the structure, Figure 1 presents a schematic overview of the natural gas supply chain.

Extraction

The first stage of the supply chain is natural gas extraction. Extraction facilities are generally clustered in regions with a high presence of natural gas reservoirs. At this stage, CO₂ emissions arise mainly from energy-intensive equipment used in extraction processes as well as from occasional gas flaring, whereas methane is released through venting, leaks, and occasional gas flaring (due to a flaring efficiency below 100%). For unconventional extraction, such as hydraulic fracturing ("fracking"), additional methane emissions occur due to gas release during drilling and the handling of flowback fluids. The extent of emissions in both cases is influenced by well integrity, the geological characteristics of the reservoir, but also the equipment quality and the frequency of maintenance.

Processing

The extracted natural gas is sent to a gas processing plant, mostly in close proximity to the gas extraction area. These processing plants are usually centralised facilities that receive raw natural gas from numerous wells in an area through a network of gathering pipelines. Processing natural gas involves the removal of impurities such as water, lead, sulphur, CO₂ and petroleum liquids like ethane, butane, and propane. This energy-intensive process leads to

emissions of CO₂ due to fossil fuel combustion.¹ The magnitude of these emissions depends on the composition and quality of the raw gas and the technology used in the processing facility. In addition, the removed CO₂ can be vented into the atmosphere or captured by carbon capture and storage technologies. Finally, methane emissions can occur through leaks in processing equipment.

Pipeline transportation

During subsequent pipeline transport, methane is emitted mainly due to leaks along the pipeline, valves or compressors, and during venting episodes for maintenance. In addition, CO₂ emissions arise from the energy needed to compress and move the gas through the pipeline network. Compressor stations are evenly spaced across the network. The importance of emissions is determined by the pipeline's length, the number of compressor stations, and the maintenance and integrity of the pipeline system. Longer pipelines and ageing infrastructure typically result in higher emissions.

LNG liquefactions

In the case of LNG, three additional supply chain elements have to be taken into account. First, liquefaction plants convert gaseous natural gas into a liquid by cooling it to -163°C (-261°F), which requires significant energy usually provided by gas or steam turbines. Liquefaction plants are large installations concentrated on the coast at dedicated (export) ports, so that their number is relatively small (less than 50 export terminals globally). For example, Norway only has one liquefaction plant, while there are fewer than a dozen active liquefaction plants in the USA. The amount of CO₂ emissions at these plants is influenced by their energy efficiency, the outside temperature, the energy carrier type used in the cooling process, and the composition of the gas being liquefied. Newer, more efficient plants tend to have lower emissions.² Besides the CO₂ emissions, methane is released due to boil-off gas (BOG)³ and leaks during the liquefaction process.

LNG shipping

LNG shipping involves the overseas transport of LNG over long distances, with emissions comprising both CO₂ and methane. CO₂ emissions mainly arise from the combustion of the ship's engine, mostly diesel or LNG. Methane emissions occur due to leaks or BOG during transport. BOG leads to methane emissions when it is used as fuel for the ship's engines (as incomplete combustion leads to methane slip) or in the rare cases when it is directly vented into the atmosphere. In cases where BOG is reliquefied, additional CO₂ emissions are emitted in the process. The distance travelled and the efficiency of the ship's engines are key factors influencing emissions, with longer journeys and older engines generally resulting in higher emissions.

LNG regasification

Finally, LNG arrives at regasification plants in (import) ports, of which there are around 30 active plants in Europe.⁴ These plants can be either onshore regasification plants or floating storage and regasification units (FSRUs). LNG is converted back into a gaseous state by heating it, which can be achieved in different ways. Both onshore plants and FSRUs mostly operate Open

¹ In addition, the removed CO₂ is sometimes vented into the atmosphere in rare cases.

² In the future, some liquefaction plants could be run on (renewable) electricity, which would greatly reduce the CO₂ emissions of this supply chain segment.

³ Boil-off gas refers to LNG that heats above -163°C (thereby turning back into gaseous form) and is released into the atmosphere.

⁴ For an overview of LNG regasification plants in Europe, see <https://ieefa.org/european-lng-tracker-september-2024-update> (accessed Oct. 7, 2024).

Rack Vaporisers, in which seawater heat is used in the regasification process. This technology implies very limited CO₂ emissions, as it only requires electricity for water pumps. Depending on the location and the time of the year, some plants might use Ambient Air Vaporisers or Submerged Combustion Vaporisers, the latter requiring the combustion of gas and leading to substantially higher CO₂ emissions. Therefore, both the efficiency of the regasification terminal and local temperature conditions are important factors in determining emission levels, with colder regions requiring more energy for vaporisation. Finally, methane can be released through leaks or boil-off gas during storage and handling.

Distribution and storage

As a last step, the natural gas arriving either through pipelines or shipping is stored and distributed to consumers. In this report, we do not consider storage in tanks in the regasification plants nor underground storage. It seems reasonable to assume that the (additional) emissions from storage in regasification terminals are small while underground storage is not a mandatory step in the supply chain (i.e., not all gas is stored before being consumed). For both storage types, the literature provides little to no quantification of emissions.

2.2 Emission intensity estimates in the natural gas supply chain

The EU imports a large majority of the natural gas it consumes. Table A.4 shows the imports into the EU by country of origin in 2023. It is important to highlight that, while Europe has started to diversify the sources of natural gas in the wake of Russia's invasion of Ukraine, only four countries (Norway, USA, Russia, Algeria) were responsible for 83% of the imports into the EU. The share of LNG has been increasing over the last years, and as of 2023 made up almost half of EU imports (44% in 2023). LNG comes from a diverse set of countries, including the USA, Qatar, Algeria, Russia, and others.

The supply chain emissions associated with natural gas from the different exporting countries present substantial variation. Under ideal data availability, one would want to compare the emissions of CO₂ and methane by each stage of the supply chain in the different countries. However, the question of natural gas supply chain emissions is characterised by imperfect data availability, so that the literature does not provide reliable estimates at this level of granularity. Therefore, we first focus on analysing total emissions (CO₂ and methane combined) by supply chain element and then focus on emissions by type of gas (i.e., separately for CO₂ and methane). We do so for a selected sample of countries for which data is available, but that covers the large majority of imports into the EU.⁵

Figure 2 presents a range of estimates for emissions by supply chain segment for different origin countries. In general, the destination market considered is Germany/Central Europe. The only exception relates to pipeline imports from Algeria, where the relevant destination market is Southern Europe.⁶

Three points are noteworthy in Figure 2. First, total supply chain emissions have a sizeable GHG intensity of sometimes even more than 20 g CO₂eq/MJ. Given a combustion intensity of 56.2 g CO₂eq/MJ of natural gas, this represents an increase of over 35 % in the total emissions of natural gas. Second, there are important differences between source countries. Norwegian pipeline gas and LNG present the lowest estimates in their respective categories. Russian

⁵ Only two types of imports representing more than 10 bcm in 2023 are missing: Russian LNG imports and pipeline imports from Azerbaijan. These constitute relatively new sources of natural gas for the European market, so that reliable estimates are still scarce.

⁶ In all studies, methane emissions are included by assuming a global warming potential (GWP) over 100 years. Results based on GWP 100 imply a smaller impact of methane emissions as compared to GWP 20 estimates presented in other of studies. We choose GWP 100 estimates to remain consistent with Baumann & Schuller (2021), who do not present GWP 20 estimates.

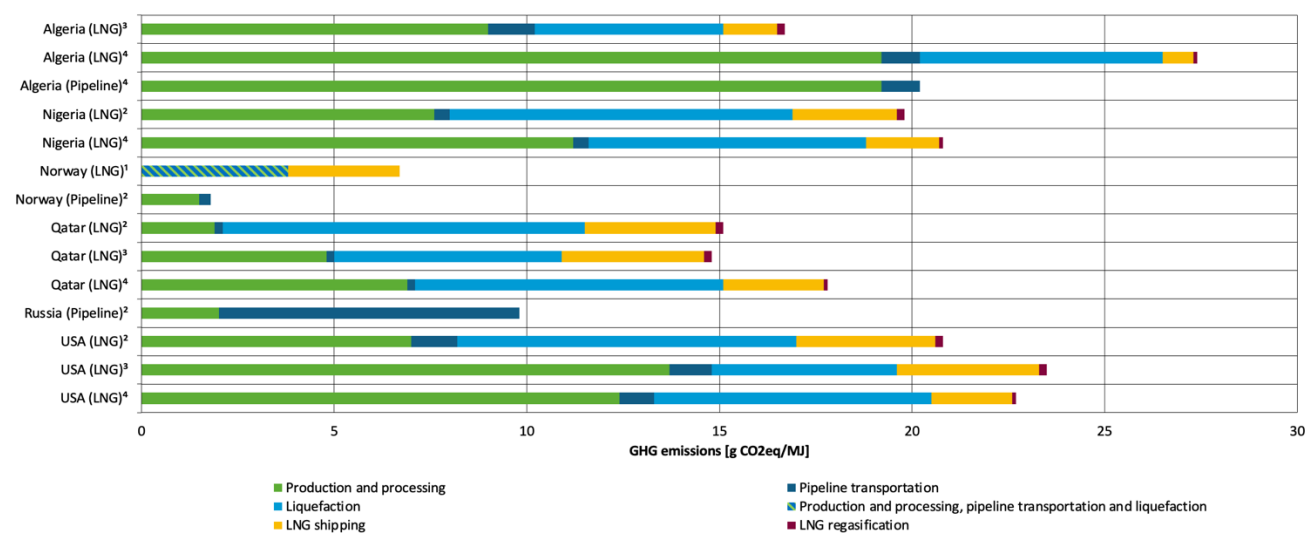
pipeline gas is reported to have an intensity below 10 g CO₂eq/MJ, although large uncertainties on methane emissions might render this a lower-bound estimate. LNG from outside of Europe is reported to have higher supply chain emissions, often above 15 g CO₂eq/MJ. Finally, important differences emerge regarding the emissions intensity of the different supply chain segments. For the majority of the available cases, the largest share of emissions comes from extraction and processing, followed by liquefaction in the cases of LNG. The importance of emissions from LNG shipping crucially depends on the distance to the European market, with Algerian LNG presenting lower values than other origin countries. Emissions from pipeline transmission only seem to play a crucial role for Russian natural gas, but emission estimates for Russian LNG are not (yet) available. LNG regasification plays a negligible role in general.

Baumann & Schuller (2021) additionally attempt to quantify emissions from gas storage and transmission in Germany. The authors quantify these emissions as 0.8 g CO₂eq/MJ in Germany (these emissions are not shown in Figure 2 but can be added to the total estimate in order to take them into account).

Figure 3 presents emissions by type of gas for a subset of the previously reported countries. Again, several points deserve attention. First, emissions of CO₂ and methane along the supply chain are highly correlated: countries with a CO₂-intensive natural gas supply chain tend to have higher methane intensity. Second, the contribution of methane in one country can vary substantially between different estimates in the literature, indicating that there is (still) high uncertainty and a lack of reliable data on methane emissions. Among the presented cases, it appears that LNG from the USA and Algeria is particularly methane-intensive. Finally, the role of other GHGs like N₂O is negligible.

Finally, it is important to acknowledge that emissions at the extraction and processing stages of natural gas might be hard to disentangle from oil in associated production. In particular, in some basins, extraction emissions are related to crude oil and other fossil fuels like natural gas and natural gas liquids, whereas processing emissions can be attributed to natural gas and natural gas liquids. Currently, the emissions of each fuel are still often calculated based on the production shares, although the granularity of production measurement might vary between sources (Vallejo et al. 2023). As explained in Chapter 3 below, the European Commission is expected to present technical guidance on this aspect in future delegated acts.

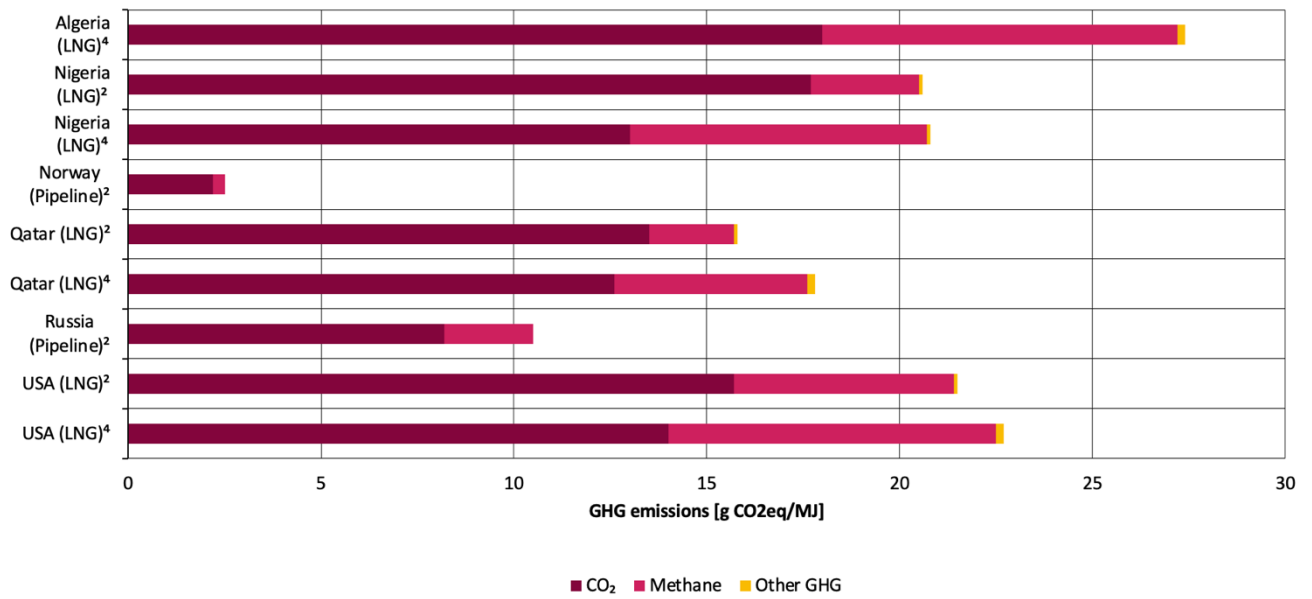
Figure 2 Supply chain emissions by supply chain segment (in CO₂eq GWP 100)



Sources: [1] Equinor (2021) [2] Baumann & Schuller (2021) [3] Wachsmuth et al. (2019) [4] Münter & Liebich (2023)

Note: Emissions for Algerian pipeline gas are calculated based on Münter & Liebich (2023) excluding LNG associated emissions, as the share of emissions from the underwater pipelines is expected to be small.

Figure 3 Supply chain emissions by type of GHG (in CO₂eq GWP 100)



Source: [2] Baumann & Schuller (2021) [4] Münter & Liebich (2023)

3 EU regulatory framework on natural gas supply chain emissions

This section provides an overview of the different instruments – both in place and planned – that regulate supply chain natural gas emissions in the current legislative framework of the EU. A key distinction in this context is whether the emissions occur within the EEA or in a third country. Hence, in this chapter, we treat these two cases separately.

Moreover, our analysis distinguishes different instruments for each step of the supply chain and each type of greenhouse gas. In doing so, we only include regulatory instruments that result in the quantification and/or reporting of emissions. Therefore, this chapter aims to identify which segments of the natural gas supply chain

- i) are already subject to emissions pricing,
- ii) are subject to MRV provisions that could allow for emissions pricing, and
- iii) would need to be subject to additional MRV provisions to allow for emissions pricing.

Table 1 presents a summary of the regulatory framework for natural gas supply chain emissions, which is subsequently discussed in the remainder of the section. The table distinguishes between regulatory instruments for stationary installations (i.e. installations at extraction, processing, pipeline transport and potential liquefaction and regasification) inside and outside the EEA and for shipping, which is subject to a specific regulation.

It is crucial to acknowledge the relative share that the different supply chain segments have in the GHG footprint of natural gas consumed in Europe. In particular, only 133 billion cubic metres (bcm) out of almost 300 bcm total natural gas consumed in Europe in 2023 was also produced within the EEA (38 bcm in the EU and 95 bcm in Norway, see Table A.4) and would, therefore, be subject to the regulation of stationary installations inside the EEA. The remaining 165 bcm were imported into the EEA and, therefore, fall into a different regulatory environment.

Table 1 Overview regulatory framework for natural gas supply chain emissions

Regulated entity or segment	GHG	EU monitoring & reporting framework	Pricing mechanism
Stationary installations (inside EEA)	CO ₂ at combustion installations > 20 MW	Monitoring and Reporting Regulation (MRR)	EU ETS 1
	CO ₂ at combustion installations < 20 MW	Monitoring and Reporting Regulation (MRR)	EU ETS 2
	CH ₄	Methane Regulation	-
Shipping (into/from EEA)	CO ₂	Maritime MRV Regulation	EU ETS 1 (100% intra-EEA + 50% for international shipping)
	CH ₄	Maritime MRV Regulation (incomplete coverage)	EU ETS 1 (100% intra-EEA + 50% for international shipping)
Stationary installations (outside EEA)	CO ₂	No MRV framework, but indicative default factors under Low-Carbon Fuels Delegated Act	-

Regulated entity or segment	GHG	EU monitoring & reporting framework	Pricing mechanism
	CH ₄	Methane Regulation (potentially incomplete coverage)	-

Source: Own compilation

3.1 CO₂ emissions from stationary installations in the EEA

As discussed in Chapter 2, direct CO₂ emissions from stationary installations along the supply chain typically arise from the combustion of fossil fuels (e.g. at power plants, compressor stations).⁷ The regulatory framework depends on the thermal input of these combustion installations, which might vary across supply chain elements and countries. Unfortunately, acquiring information on the exact thermal capacity of the facilities involved in the supply chain of natural gas within Europe is challenging. However, our assessment concludes that most combustion installations along the natural gas supply chain present rated thermal inputs above 20 MW.⁸ In that case, these installations would be in the scope of the EU ETS 1, regulated under Directive 2003/87 (hereinafter ETS Directive)⁹ and monitored under the Monitoring and Reporting Regulation (hereinafter MRR)¹⁰.

This analysis suggests that a large share of CO₂ combustion emissions (including from flaring) at stationary installations along the supply chain in Europe are already priced under the EU ETS 1. In addition, the EU ETS 2 will additionally price CO₂ combustion emissions from combustion installations with rated thermal input below 20 MW starting in 2027. To the extent that such installations play a role in the natural gas supply chain, they will also be subject to carbon pricing. We therefore conclude that CO₂ emissions at stationary installations along the natural gas supply chain in Europe are already or will soon be subject to MRV and emissions pricing.

3.2 Methane emissions from stationary installations in the EEA

The Methane Regulation entered into force in August 2024 and imposes new obligations on operators across the supply chain of natural gas, from extraction to distribution.¹¹ The Regulation has three main new types of obligations: providing MRV of methane emissions from active assets, emission mitigation requirements for active assets (e.g. through leak detection and repair (LDAR) mandates and venting and flaring restrictions) and MRV and mitigation requirements for inactive assets.

The new standards on MRV for emissions of active assets are set in Article 12 of the Methane Regulation and provide a major point of departure from current industry practices, as operators

⁷ In the rare cases where CO₂ emissions are vented into the atmosphere during natural gas processing, these are not subject to reporting under the EU ETS 1. However, these constitute a negligible share of total supply chain emissions.

⁸ We base this assessment on the fact that the European Union's Transaction Log (EUTL) does include the only liquefaction plant on European soil (Hammerfest liquefaction plant in Norway), and a range of compressor stations along major natural gas transport pipelines as well as several offshore plants. As per Annex I of the ETS Directive, installations are covered under the EU ETS 1 as long as the rated thermal input of all technical units at the installation larger than 3 MW sums up to at least 20 MW.

⁹ Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 establishing a system for greenhouse gas emission allowance trading within the Union: <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A02003L0087-20240301>

¹⁰ Implementing Regulation (EU) 2018/2066 of 19 December 2018 on the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council: <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A02018R2066-20240701>

¹¹ Analogous requirements are imposed on assets along the crude oil value chain. In addition, in the energy sector, the Regulation also covers methane emissions from the coal sector.

will have to meet increasingly more detailed quantification requirements over time. Reliably monitoring methane emissions is a complex matter, and Article 32 of the Regulation calls on the European Commission to specify a set of standards and technical prescriptions in the coming years. These documents are expected to closely follow OGMP 2.0 technical guidance documents, which are stipulated to be used in the meantime.¹² The Regulation's timeline envisions that, from 2028 onwards, methane emissions along the whole supply chain of natural gas in Europe will be subject to the highest level of MRV regulation under the OGMP 2.0 framework (i.e., Level 5) and third-party verification. In addition, from 2030 onwards, EU producers will have to demonstrate that their methane intensity of production (not including supply chain elements as liquefaction, pipeline transport or regasification) remains below a yet-to-be-defined maximum methane intensity value.¹³

The Regulation will not only apply to the 27 EU Member States but is also likely to be adopted by three European Economic Area (EEA) countries – Iceland, Liechtenstein, and, most importantly, Norway, subject to the EEA Joint Committee decision (Olczak et al. 2024). At the time of writing, in August 2025, it is yet to be decided whether Norway will fully follow the EU approach or if some adjustments will be needed.

Assuming a successful roll-out of the Methane Regulation and that all EEA countries become subject by 2030, this new legislative framework would provide the first MRV system of methane emissions along the EU supply chain of natural gas. However, important uncertainties remain regarding the reliability of the methane emissions data resulting from this MRV framework. As a diffuse source, methane emissions are considerably more complex and require accurate measurements, while CO₂ combustion emissions quantification can be carried out with emission factors reliably. Achieving accurate reporting will require substantial technological innovations and the widespread diffusion of new practices within the industry. A lack of measurement accuracy would have implications if methane emissions were to be covered by the EU ETS, see Section 5.2.1.

3.3 CO₂ and methane emissions from shipping

Combustion-related CO₂ and methane emissions from all ships (including LNG tankers) are regulated under a different framework than emissions from stationary installations. Delegated Regulation 2023/2776 has amended the original Regulation 2015/757, hereinafter Maritime MRV Regulation¹⁴. Consequently, from 2024 onwards, all shipping engines in ships arriving at or departing from the EEA – including those in LNG tankers – will provide MRV of both their CO₂ and methane combustion-related emissions.¹⁵ Importantly, the scope does not reflect methane leaks, as these are not combustion-related.¹⁶ This has led to a debate on what share of methane emissions is reflected in the current regulatory design (Olczak & Piebalgs 2024, Balcombe et al. 2022).

¹² The Oil and Gas Methane Partnership (OGMP) is a measurement-based voluntary reporting framework for the oil and gas industry led by the United Nations Environment Programme (UNEP). It defines up to five levels of reporting stringency, with the highest level (Level 5) combining source-level quantification with separate site-level measurements (see Olczak et al. 2024 for further details).

¹³ The Regulation orders the creation of national Competent Authorities to implement the Regulation and defines a compliance framework with fees for non-compliance.

¹⁴ Commission Delegated Regulation (EU) 2023/2776 of 12 October 2023 amending Regulation (EU) 2015/757 of the European Parliament and of the Council as regards the rules for monitoring greenhouse gas emissions and other relevant information from maritime transport: https://eur-lex.europa.eu/eli/reg_del/2023/2776

¹⁵ CO₂ emissions from shipping engines had already been monitored since 2018.

¹⁶ The framework also does not account for the rare cases where BOG is directly vented.

Combustion-related emissions are not directly measured but quantified based on emission factors, and methane emissions are converted into CO_{2e} emissions using the Global Warming Potential 100. The use of emissions factors for methane might be a consequence of a regulatory focus on shipping CO₂ emissions, which were assumed to play a more important role (Olczak & Piebalgs 2024). The chosen methane slippage coefficients range from 0.2% to 3.1% of the mass of the LNG used as fuel, depending on the type of engine. By nature, standard factors are subject to uncertainties compared to more refined MRV frameworks.

With the inclusion of the maritime sector under the EU ETS 1, emissions from LNG tankers will not only be quantified and monitored, but also face emission costs. The amended ETS Directive stipulates that regulated actors will have to surrender allowances against their CO₂ emissions from 2024 onwards, while methane emissions will be included from 2026 onwards. However, coverage will depend on the port of origin of a vessel arriving at an EEA port. In particular, the Regulation requires the surrender of allowances for 100% of CO₂ emissions for voyages between EEA Member States and 50% of emissions for extra-EU voyages arriving or departing from a port under the authority of an EEA Member State. As shown in Table A.4, only a minor part of LNG ships arriving at European ports have started in countries subject to the EU ETS 1. In 2023, this was the case for only 5 bcm of natural gas from Norway, amounting to just 3.8% of total EU LNG imports. Emissions from LNG shipping in these imports will be fully priced by the EU ETS 1 from 2026 onwards. The remaining emissions from shipping will only be included to 50%.¹⁷

We conclude that combustion-related CO₂ and methane emissions from shipping engines are already quantified under the current legislative framework of the EU and fully or partially priced, depending on the port of origin. However, methane emissions from leaks are not monitored under any current policy instrument, which leaves a share of total methane emissions unregulated.

3.4 CO₂ emissions from stationary installations outside the EEA

At the present moment, there is no robust MRV system for CO₂ emissions emitted along the natural gas supply chain outside the EU. However, the Low-Carbon Fuels Delegated Act might prove useful as a first attempt to quantify supply chain CO₂ emissions, which could subsequently serve as a basis for carbon pricing (e.g. under CBAM).¹⁸ This piece of legislation will provide the technical guidance for emissions quantification for all types of low-carbon fuels to facilitate ramping up their production. In order to be recognised as such, low-carbon fuel producers must prove a certain level of savings in life cycle GHG emissions compared to a specified benchmark. Importantly, these savings must take into account emissions outside the EU (see the EU Hydrogen and Gas Decarbonisation Package, Article 9 of the Directive 2024/1788¹⁹). This framework will only apply to a small share of the fuels market, namely those aiming at low-carbon fuel certification. However, the draft document proposes some quantification guidelines that might be relied on for the estimation of CO₂ emissions along the natural gas supply chain outside the EU. These could serve as a first step to include CO₂ emissions outside the EEA under the EU ETS 1 and CBAM, but a more robust MRV system would still be necessary (see Section 6.1.1).

¹⁷ LNG arriving at the UK and entering via pipeline networks into the EU is also not covered.

¹⁸ See https://energy.ec.europa.eu/publications/commission-delegated-regulation-eu-specifying-methodology-assessing-greenhouse-gas-emissions-savings_en (accessed July 31st, 2025).

¹⁹ Directive (EU) 2024/1788 of the European Parliament and of the Council of 13 June 2024 on common rules for the internal markets for renewable gas, natural gas and hydrogen: <https://eur-lex.europa.eu/eli/dir/2024/1788> (accessed July 31, 2025)

Under the Low-Carbon Fuels Delegated, CO₂ emissions from natural gas are addressed differently depending on whether the natural gas is obtained from an incorporated process or not.²⁰ If the gas is obtained from an incorporated process, the Low-Carbon Fuels Delegated Act states that emissions “shall be determined based on data from their actual production process. This shall include all emissions arising due to their production over the whole supply chain (including emissions arising from the extraction of the primary energy required to make the input, process and transport it).” In the case of emissions from natural gas not obtained in an incorporated process, emissions should be calculated based on supply chain emission values defined in Appendix B of the Low-Carbon Fuels Delegated Act, where supply chain CO₂ emissions of pipeline natural gas are given a default value of 4.9 gCO₂/MJ. Compared to the estimates provided in Figure 3, this number is an upper bound for Norwegian pipeline natural gas and a lower bound for Russian pipeline natural gas. The Delegated Act does not provide default factors for the supply chain segments relevant for LNG (i.e. liquefaction, shipping and regasification). These emissions would have to be added separately.

3.5 Methane emissions from stationary installations outside the EEA

In addition to creating new obligations for operators of natural gas assets in the EU, Chapter 5 of the Methane Regulation also includes new regulations on importers of natural gas. Similarly to the obligations for EU operators, the Regulation sets out a timeline of increasingly stringent MRV obligations over time (see Table 2).

As of 2025, all importers will have to report to the Competent Authorities information on the producers of the natural gas imported. Most importantly, this information includes what type of methane measurement systems the producers have in place and whether these comply with UNFCCC reporting requirements or with OGMP 2.0 standards. This requirement applies to all types of contracts, both existing and new/renewed contracts. However, the next set of requirements only applies to new contracts or those renewed after August 2024. From 2027 onwards, importers will have to demonstrate that producers of imported natural gas are subject to equivalent MRV measures compared to European producers (Article 12 or OGMP 2.0 Level 5). This equivalence is possible at the producer (“asset”) level or, for countries recognised by future implementing acts of the Commission, as equivalent at the country level. From 2028 onwards, importers will be obliged to report the methane intensity of the imported natural gas. Finally, for contracts concluded/renewed after August 2030, the methane intensity will have to be below a yet-to-be-defined maximum methane intensity. Importers under existing contracts will only be obliged to attempt and report all reasonable efforts to comply with the provisions stipulated for new contracts.

Table 2 Implementation timeline for EU importers under the Methane Regulation

Type of contract	Monitoring requirements
All contracts	Importers provide information on MRV in Annex IX (1)-(7)
New/Renewed contracts (after 4 th August 2024)	By 2027, Importers demonstrate that imported gas is subject to equivalent MRV measures at the level of the producer
Existing contracts as of 01/2027	Importers “shall undertake all reasonable efforts” e.g. contract amendment

²⁰ According to the Low-Carbon Fuels Delegated Act, incorporated processes are defined as “processes that take place in the same industrial complex, and reuse heat or other hard-to-transport outputs of one of the processes”. https://energy.ec.europa.eu/publications/commission-delegated-regulation-eu-specifying-methodology-assessing-greenhouse-gas-emissions-savings_en (accessed August 5, 2025)

Type of contract	Monitoring requirements
New/Renewed contracts as of 08/2028	Importers report the methane intensity of imported natural gas
Existing contracts as of 08/2028	Importers “shall undertake all reasonable efforts” e.g. contract amendment
New/Renewed contracts as of 08/2030	Importers demonstrate methane intensity is below the maximum methane intensity

Source: Olczack et al. (2024)

In principle, these stipulations imply a first attempt to provide an MRV framework for methane emissions of the natural gas supply chain outside the EU. However, three main drawbacks of the Regulation might provide challenges if this MRV framework is to be relied on for methane pricing:

- ▶ There is still much uncertainty regarding MRV that will have to be resolved by future delegated acts, including the allocation of methane emissions to oil and gas when extracted in the same wells.²¹ However, the main challenge for MRV is that importers are only obliged to report the methane intensity of production of the natural gas they import. Therefore, emissions from pipeline transport and liquefaction are not going to be reflected in this data. If this is the case, Article 30 of the Regulation proposes the creation of a methane intensity database that should provide a rich set of information, including “indicative values estimating the methane emissions related to the transport” of natural gas. However, it is at the present stage unclear what data sources would underlie such indicative values, and if these estimates would cover liquefaction emissions.
- ▶ The requirement to provide information on the methane intensity of production is only enforceable for new or renewed contracts (after 4th August 2024). This is particularly challenging in the context of natural gas imports, where import contracts often run for more than 20 years (Neumann et al., 2015). This means that, even after 2028, some imported natural gas might not be subject to methane intensity reporting. The relevance of this issue will depend on how national regulators interpret what constitutes “all reasonable efforts”.
- ▶ Producers need to cooperate and facilitate information so that importers can comply with the Regulation. At the present stage, it is difficult to foresee to what degree this will be the case, and the Regulation does not specify what happens if the producer refuses to provide the requested information (Olczak et al. 2024).

In addition to the Methane Regulation, the Low-Carbon Fuels Delegated Act also includes provisions on supply chain methane emissions of natural gas. However, it heavily relies on the Methane Regulation, as it stipulates that the methane intensity of production shall be calculated as defined under the Methane Regulation. For cases where the calculation of supply chain methane emissions is not possible, the Delegated Act provides emission factors for pipeline natural gas as stipulated in Appendix B, which amount to 5.32 g CO₂eq/MJ. Given the uncertainties of current methane intensity estimates, it is unclear if 5.32 g CO₂eq/MJ is a realistic estimate of total methane emissions along the full supply chain of natural gas. As presented above, Figure 2 shows a range of 3 g CO₂eq/MJ to more than 20 g CO₂eq/MJ. As for the case of CO₂, the document does not provide default factors for natural gas liquefaction, shipping and

²¹ This is expected to be provided by a delegated act prior to the 2028 reporting deadline.

regasification. Instead, it refers back to the methodology for emissions quantification in an incorporated process outlined in the Appendix.

4 Regulation of supply chain emissions in other countries

Three main elements need to be considered when investigating the regulation of supply chain greenhouse gas emissions of natural gas (and oil) in other constituencies than the EU:

- ▶ Which GHG emissions are regulated? Only methane or also CO₂?
- ▶ Which supply chain elements are included? Only extraction (including or excluding processing?), or also pipeline transport and/or LNG liquefaction?
- ▶ What does the regulation include? Facility-level measurement of emissions or the use of default factors? Pricing of emissions or prohibitions?

In the following, we provide an overview of the supply chain methane and CO₂ emissions regulation in Norway, Australia, the USA, and Canada. These are the countries that have been active in addressing GHG reduction in the oil and gas sector with some form of pricing or emission penalty payments. In all these cases, only the production stage of the supply chain is addressed (“upstream”). However, none of these countries has yet introduced strict methane measurement regulation in the spirit of OGMP 2.0 Level 5 or the EU Methane Regulation.²²

No similar action with pricing methane emissions from the natural gas supply chain is taken in other producing countries.²³ Some oil and gas producing countries have founded the so-called Net-Zero Producers Forum in 2021 where they commit in principle to and report on efforts to reduce upstream GHG emissions.²⁴ Other international fora and coalitions also include reducing methane emissions from oil and gas production, such as the Oil and Gas Climate Initiative and the Oil and Gas Decarbonization Charter launched in 2023.²⁵ The absence of globally widespread legally binding regulations on methane emissions and, in particular, of methane pricing has been deplored by the stakeholders and scientists for many years (e.g., Shindell et al. 2024).

4.1 Norway

Norway is not part of the EU, but as a member of the European Economic Area, it adopts most EU legislation. In particular, it is part of the EU ETS 1. In addition, Norway has had regulation of upstream CO₂ and CH₄ emissions that goes beyond the EU ETS 1 for many decades.

First, regarding methane emissions, under the Pollution Control Act, a permit issued by the Norwegian Environmental Agency is required for the offshore and onshore petroleum sector (i.e., oil and gas sector). Direct emissions of methane (venting and fugitive emissions) are regulated through emission limits set in the facility-specific permit. As a general requirement,

²² The Methane Regulation (EU) 2024/1787 requires importers since May 2025 to provide information, *i.a.*, on the current MRV practices of the producer. The European Commission shall publish this information in a “Methane Transparency Database” from February 2026 on which it will provide more clarity of the equivalence of methane emission monitoring of other jurisdictions. See Olczak (2025), p. 6.

²³ There is one notable omission in our list of countries, namely Russia. According to Evans & Roshchanka (2014), Russia has charged methane fines as part of its policy of environmental charges which also addressed other pollutants. According to Evans & Roshchanka (2014), the methane fine was differentiated by the size of emissions and whether a regulated emission threshold was exceeded or not. The highest fine was 1250 rubles per tCH₄ (~ 40 USD in 2014, ~ 15 USD in 2025). Company-level emissions were calculated, not measured. However, it is not possible to find updated information on this policy. The very high methane emissions from the Russian oil and gas sector (e.g., IEA Methane Tracker, Shindell et al., 2024) are testimony that either the pricing has been too low to be effective or that it is not enforced or both. Alternatively, the policy might also have been abandoned.

²⁴ Members of the Oil and Gas Climate Initiative are twelve large multinational companies, both international and state-owned oil and gas companies (see <https://www.ogci.com/>, accessed July 31, 2025). Similarly, the more than 50 signatories of the Oil and Gas Decarbonization Charter are also international and state-owned oil and gas companies (see <https://www.ogdc.org/>, accessed December 11, 2025).

²⁵ 92 countries, including Norway, Australia, Canada, the USA, and Russia. <https://www.ccacoalition.org/> (accessed April 9, 2025).

the emission limits are based on best available technology (as defined nationally or in the EU), assessed individually for each facility.

Norway has banned routine flaring since 1970. Flaring of methane is only permitted when necessary for safety reasons, based on permits issued by the Ministry of Petroleum and Energy (IEA, 2022b). Each facility has to perform site-specific monitoring and reporting of methane emissions. Methane emissions are taxed as part of the country's tax code: a tax of NOK 16.89 per standard cubic meter (Sm^3) for vented natural gas offshore (2024), which is equivalent to approximately EUR 1.50 per m^3 .²⁶ This tax has been raised regularly in recent years.

Second, addressing CO_2 emissions in addition to the EU ETS 1, combustion of natural gas, oil or diesel for power and heat generation at petroleum producing installations has to be metered and reported and is taxed in accordance with the CO_2 Tax Act on Petroleum Activities.²⁷ For 2024, the tax rate was NOK 1.85 (ca. EUR 0.16) per Sm^3 of gas and NOK 2.10 (ca. EUR 0.18) per litre of oil or condensate. For combustion of natural gas, this corresponds to NOK 790 (ca. EUR 67) per t CO_2 . This additional CO_2 tax has incentivised electrification of many oil and gas production installations in Norway.

4.2 Australia

In 2023, Australia revised and strengthened its so-called safeguard mechanism (in place since 2014), which covers the largest emitters, including energy producers (coal mines, oil and gas producing facilities) with their emissions of CH_4 , CO_2 and nitrous oxide. Large emitters are defined as those with emissions of more than 100Mt CO_2e /year per facility. The safeguard mechanism sets a baseline emission and requires reductions over time. The baselines start at actual facility emissions levels, and over time move to industry average, and that industry average decreases by 4.9 % every year.²⁸ Facilities, such as oil and gas producing facilities, are required to measure and report their greenhouse gas emissions, including methane, in each fiscal year, based on the country's Greenhouse and Energy Reporting Act.²⁹ The reporting is not based on actual measurement of methane emissions, and there seems to be considerable under-reporting of emissions (Denis-Ryan et al., 2024).

In order to reduce a facility's "net emissions", this emitting facility can purchase and surrender Australian carbon credit units (ACCUs), which are traded on a market. Market prices have been in the order of 30 to 40 AUD per t CO_2e in 2023/2024 (i.e., 18.50 to 25 EUR). If net emissions exceed the baseline emissions, a penalty payment is charged. As of 1 January 2023, a penalty unit is 275 AUD (ca. EUR 170) per tonne for excess emissions.³⁰ Overall, this pricing scheme has not been effective in reducing methane emissions from the upstream energy sector in Australia since 2014, probably because of a mix of low emission data quality, too low emission prices, and the possibility to purchase offsets (Denis-Ryan et al., 2024).

²⁶ As a rule of thumb, the average exchange rate between Euro (EUR) and Norwegian Kronor (NOK) is 1:10. On March 6, 2025, the exchange rate was EUR 1 = NOK 11.7166845.

([https://www.ecb.europa.eu/stats/policy_and_exchange_rates/euro_reference_exchange_rates/html/eurofxref-graph-nok.en.html#:~:text=The%20European%20Central%20Bank%20\(ECB\)%20is](https://www.ecb.europa.eu/stats/policy_and_exchange_rates/euro_reference_exchange_rates/html/eurofxref-graph-nok.en.html#:~:text=The%20European%20Central%20Bank%20(ECB)%20is), accessed March 7, 2025).

²⁷ <https://www.norskipetroleum.no/en/environment-and-technology/emissions-to-air/> (accessed Oct. 7, 2024).

²⁸ See <https://www.dceew.gov.au/sites/default/files/documents/safeguard-mechanism-reforms-factsheet-2023.pdf> (accessed on April 10, 2025).

²⁹ <https://www.legislation.gov.au/C2007A00175/latest/text> (accessed on March 7, 2025).

³⁰ On Oct. 7, 2024, the 1 EUR 1 was 1.6155 AUD

([https://www.ecb.europa.eu/stats/policy_and_exchange_rates/euro_reference_exchange_rates/html/eurofxref-graph-aud.en.html#:~:text=The%20European%20Central%20Bank%20\(ECB\)%20is](https://www.ecb.europa.eu/stats/policy_and_exchange_rates/euro_reference_exchange_rates/html/eurofxref-graph-aud.en.html#:~:text=The%20European%20Central%20Bank%20(ECB)%20is), accessed on Oct. 7, 2024).

4.3 USA

As a producer of oil and gas with substantial CH₄ emissions, in particular from venting in onshore oil and gas production (IEA 2024, p. 74), the USA, under the Biden administration, aimed at reducing methane emissions from the oil and gas sector. Several measures were taken between 2021 and 2024 with a “carrot and stick approach with incentives and penalties” (IEA 2024, p. 75). A mix of federal rules and financial mechanisms (e.g., technology innovation in CH₄ measurement) was introduced in the 2022 update of the US Methane Emissions Reduction Action Plan (MERP), where some of the rules and standards had to be implemented by the states, others by the federal Environmental Protection Agency (EPA). The IEA (2024, p. 77) emphasised that there was “a strong focus on using regulatory measures to mitigate methane, especially from orphan wells and work on developing a measurement, monitoring, reporting and verification tool to measure methane intensity.” These actions were supported during the Biden Administration (2021 to early 2025) by funding programmes under the BIL [Bipartisan Infrastructure Law] and the Inflation Reduction Act (IRA).

However, even though pricing methane emissions was not in the focus of the Biden administration’s methane policy, the Inflation Reduction Act also introduced, for the first time, a methane tax that was supposed to be implemented and levied by the Environmental Protection Agency (EPA). This methane tax, implemented as a “waste emissions charge” (WEC), targeted oil and gas production installations under certain conditions, notably very high methane emissions above 25,000 tCO₂eq. per year. The tax was scheduled to start to be levied for emissions of 2024 (first due with the reporting and tax declaration in 2025). The tax was scheduled to escalate starting with a level of 900 USD/t CH₄ (equivalent to 30 USD/t CO₂) in 2024, rising to 1200 USD/t CH₄ (~40 USD/t CO₂) in 2025 and to 1500 USD/t CH₄ (~50 USD/t CO₂) in 2026.³¹ There were a significant number of exemptions depending on the production level and whether there was already compliance under EPA rules. Yet, this tax introduced the need to measure and report CH₄ emissions (MRV), which were part of the EPA’s Greenhouse Gas Reporting Program.³² However, the late implementation of the WEC – only after the presidential election in November 2024 – made it applicable to so-called “Congressional repeal” which the Republican-dominated Congress voted in February 2025 and President Trump signed in March 2025, which effectively repealed the WEC rule.³³

In addition, during the Biden term, the EPA introduced rulemaking in the “super emitter response program” and the New Source Performance Standards for oil and gas operations, which both expand the Clean Air Act. Moreover, the Pipeline and Hazardous Materials Safety Administration introduced rules on pipeline leakage and channelled BIL funding for pipeline modernisation.³⁴ Furthermore, the Department of Energy (DOE) started a Methane Mitigation Technologies (MMT) Multi-Year Program that supports MRV, including funding for technology innovation for measurement, with 1.5 billion USD (IEA 2024, p. 75). As of August 2025, it is unclear whether and how the Trump administration will continue these programs of the previous government.

³¹ [https://www.epa.gov/inflation-reduction-act/waste-emissions-charge#:~:text=The%20WEC%20starts%20at%20\\$900%20per](https://www.epa.gov/inflation-reduction-act/waste-emissions-charge#:~:text=The%20WEC%20starts%20at%20$900%20per) (accessed October 7, 2024)

³² <https://www.epa.gov/ghgreporting> (accessed Oct. 7, 2024)

³³

[https://ballotpedia.org/Waste_Emissions_Charge_for_Petroleum_and_Natural_Gas_Systems:_Procedures_for_Facilitating_Compliance,_Including_Netted_and_Exemptions_rule_\(2024\)_](https://ballotpedia.org/Waste_Emissions_Charge_for_Petroleum_and_Natural_Gas_Systems:_Procedures_for_Facilitating_Compliance,_Including_Netted_and_Exemptions_rule_(2024)_) (accessed July 31, 2025)

³⁴ <https://www.phmsa.dot.gov/news/usdot-announces-bipartisan-pipes-act-proposal-modernize-decades-old-pipeline-leak-detection#:~:text=Section%20113%20of%20the%20bipartisan%20PIPES> (accessed Oct. 7, 2024)

Regarding CO₂, there are no comprehensive US-wide federal rules. Only a few regional initiatives have introduced carbon pricing, namely the Regional Greenhouse Gas Initiative (RGGI) in several Northeastern US states as well as initiatives on the West Coast. However, only the Californian and Washington systems cover a large range of GHG emissions (including methane) and include natural gas production in their sectoral scope.³⁵

4.4 Canada

Canada has had regulations on flaring and venting in place for many years.³⁶ In 2018, the country implemented additional methane emission regulation, which foresees a gradual strengthening of rules: Leak detection and repair (LDAR) since 2020, limits on venting at production sites since 2020, and a ban on venting from fracking since 2023.³⁷ The government also provides funding for investments in methane emission reduction, partly in response to the economic downturn during Covid, as part of the Emissions Reduction Fund (IEA 2022a).

In late 2023, the Canadian government proposed to introduce a cap-and-trade system on emissions only from the upstream oil and gas sector.³⁸ This would set a regulated – and decreasing – limit on emissions from the upstream oil and gas sector and produce a price for emissions from 2030 onwards. The proposition is still under discussion as of March 2025. However, there are fears that a cap-and-trade system alone would not result in the methane emission reductions required to meet Canada's international commitments. Hence, the federal government has also proposed additional amendments to the Methane Regulation. They would introduce mandatory methane measurement at oil and gas facilities to start on January 1, 2027, but they have not been decided as of summer 2025.³⁹

In early 2025, Canada repealed its consumer carbon price and the carbon pricing of large emitters was under discussion as of spring 2025. The proposed cap-and-trade system for the oil and gas sector would complement the system in place in Canada, where all provinces/territories are required to have a carbon pricing system and can choose between a federal system or their own system. The federal backstop consists of two instruments: “a regulatory charge on fuels and a baseline-and-credit ETS for emissions-intensive and trade-exposed industrial facilities called the Output-Based Pricing System (OBPS)”.⁴⁰ The OBPS puts a price on GHG emissions (incl. CO₂ and CH₄) from emitters that emit 50,000 tCO₂e or more per year and covers mostly manufacturing sectors.⁴¹ The so-called excess emissions charge is 65 CAD per t CO₂e in 2023 and

³⁵ See World Bank Carbon Pricing Dashboard (https://carbonpricingdashboard.worldbank.org/compliance/factsheets?instrument=ETS_US_California, accessed on Oct. 7, 2024).

³⁶ In 2009, the *Canada Oil and Gas Drilling and Production Regulations* banned flaring and venting unless the federal energy regulator permits them or they are necessary because of an emergency. In 2016, Canada also endorsed World Bank's Zero Routine Flaring by 2030 initiative (<https://flaringventingregulations.worldbank.org/canada-federal>, accessed July 31, 2025).

³⁷ <https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/proposed-methane-regulations-additional-information.html> (accessed on Oct. 7, 2024)

³⁸ <https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/oil-gas-emissions-cap.html> (accessed on Oct. 7, 2024)

³⁹ <https://gazette.gc.ca/rp-pr/p1/2023/2023-12-16/html/reg3-eng.html> and <https://pollution-waste.canada.ca/environmental-protection-registry/regulations/view?id=146> (accessed on August 6, 2025)

⁴⁰ https://carbonpricingdashboard.worldbank.org/compliance/factsheets?instrument=Tax_CA (accessed on Oct. 7, 2024)

⁴¹ https://www.canada.ca/en/environment-climate-change/news/2018/01/output-based_pricingsystemregulatoryframework.html (accessed on Oct. 7, 2024)

will increase by 15 CAD per calendar year until 2030,⁴² resulting in an excess emissions charge of 170 CAD/t CO₂e in 2030.⁴³

⁴² As a rule of thumb, 1 EUR is approximately 1,50 CAD. On Oct. 7, 2024, EUR 1 = CAD 1.4914 ([https://www.ecb.europa.eu/stats/policy_and_exchange_rates/euro_reference_exchange_rates/html/eurofxref-graph-cad.en.html#:~:text=The%20European%20Central%20Bank%20\(ECB\)%20is](https://www.ecb.europa.eu/stats/policy_and_exchange_rates/euro_reference_exchange_rates/html/eurofxref-graph-cad.en.html#:~:text=The%20European%20Central%20Bank%20(ECB)%20is)). 65 CAD are approximately 43.50 EUR.

⁴³ <https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system.html> (accessed on Oct. 7, 2024)

5 Pricing supply chain methane emissions inside the EEA

Pricing supply chain emissions of natural gas represents one approach to target an important source of GHG emissions that has so far not been carefully monitored and much less exposed to a price signal. Such a price signal would incentivise innovations and abatement of supply chain emissions in an economically efficient way. This would address an otherwise crucial inefficiency in the upcoming energy transition: the (lack of a) level playing field between natural gas and low-carbon alternatives. Complete pricing of supply chain emissions of natural gas could enable an economically balanced playing field when directly comparing natural gas to low-carbon alternatives and incentivise the use of (renewable) electricity along supply chain segments like LNG cooling. In addition, pricing supply chain emissions would also translate into restoring price incentives in downstream markets like the ones for green vs. blue hydrogen. Abstaining from pricing supply chain emissions of natural gas might allow natural gas to play a more important role during the energy transition.

This chapter sketches options to price supply chain emissions from natural gas emitted in Europe. This is a prerequisite for the inclusion of emissions occurring outside of Europe under the CBAM. The potential analogous expansion of CBAM is discussed in Chapter 6, while the analogous case of crude oil supply chain emissions pricing is reported in Appendix A.1.

As concluded in Chapter 3, CO₂ emissions along the natural gas supply chain emitted in Europe are already subject to MRV and carbon pricing under the EU ETS 1. Therefore, this chapter exclusively focuses on the pricing of methane emissions along the natural gas supply chain occurring inside the EEA. For our analysis, we assume a timeline for implementation starting after 2030.

5.1 General considerations for methane pricing under the EU ETS 1

The choice of emissions trading scheme

A first fundamental regulatory choice is whether to price methane emissions along the European supply chain under EU ETS 1 or 2. The EU ETS 1 regulates emissions at the point of combustion (the emitting installation). The EU ETS 2 (expected to be fully functional from 2027 onwards) regulates emissions upstream, i.e. at the point where fuels are supplied for consumption, and covers mainly fuels consumed by road transport and buildings, but also by small industrial installations and combustion units. It relies on default emission factors per fuel.⁴⁴

In principle, methane supply chain emissions from natural gas emitted inside the EEA could be included in either of the two systems. We explore the inclusion into the EU ETS 1 rather than into the EU ETS 2 for the following reasons:

- ▶ CO₂ emissions from the extraction, processing, transmission network pipeline transport, liquefaction and regasification of natural gas in the EEA are already included in the EU ETS 1. These regulated entities are already familiar with the emissions trading scheme, both as a complex policy instrument and from an allowance trading and compliance perspective. Thus, extending the coverage to another gas (methane) might build upon experience from both installation operators and competent authorities. This does not apply to methane emissions MRV, which is complex and substantially different from CO₂ emissions MRV.
- ▶ The EU ETS 1 typically relies on measured fuel inputs by installation to determine emissions, while the ETS 2 operates with default values. Supply chain methane emissions differ widely depending e.g. on asset maintenance. Relying on actual measurement would therefore imply

⁴⁴ Fuels delivered to installations under the ETS 1 are exempted under the ETS 2 to avoid double pricing.

benefits in terms of accuracy. This option would only be available under an inclusion in the EU ETS 1.

- ▶ An inclusion into the EU ETS 1 would allow for the implementation of carbon leakage protection measures. Carbon leakage may occur if competitors from third countries that do not face the same carbon cost have an advantage compared to EU industries, which may lead to a relocation of production or investments. To avoid this possibility, the CBAM has been introduced and could potentially be expanded to include natural gas (and other energy carriers), thereby pricing supply chain emissions outside the EEA of imported natural gas.

Scope expansion under the ETS Directive

From a regulatory perspective, pricing methane supply chain emissions would entail including new activities under Annex I of the ETS Directive. Similar extensions have precedents in the EU ETS 1, which has expanded the range of activities covered over the years. The required next step would be the addition of activities along the natural gas supply chain (e.g. “natural gas extraction and processing”, “natural gas pipeline transportation”) and the precise definition of installations. Some of these installations are already regulated under the EU ETS 1. For example, a natural gas processing plant might have a power plant with thermal input above 20 MW, or a pipeline might have a compressor station with a thermal input above 20 MW. In contrast, other assets, such as gas pipelines, might be considered new installations.⁴⁵ Additionally, it should be specified that these new activities target methane emissions, thereby leaving the thermal input criteria for CO₂ combustion emissions unchanged. A precedent for such extension to methane is the recent inclusion of methane from ship engines as a new type of gas.

EU ETS 1 cap adjustments

The inclusion of new activities under the EU ETS 1 is often associated with an according cap adjustment. However, for the case of supply chain methane emissions, this involves uncertainties that did not play a role in previous cap adjustments based on CO₂ emissions and that should be taken into account when calculating the cap adjustment (Piria & Görlach 2024). We categorise these uncertainties into three categories:

- ▶ **Baseline methane emissions:** at the moment, even the best available estimates on methane emissions in Europe (as provided by the IEA Methane Tracker) imply very substantial uncertainties. Calculating a cap adjustment on this basis might therefore prove difficult. The MRV provision under the Methane Regulation will improve on this challenge. However, as discussed in Chapter 3.2, the Methane Regulation’s timeline implies that a detailed assessment based on OGMP 2.0 Level 5 methodologies will only become available from 2027 onwards. In addition, the actual level of emissions accuracy under the Methane Regulation framework will have to be scrutinised. A reporting period before the cap adjustment could serve as a way to address both the approximate level and the yearly variation in supply chain methane emissions, but it will not fundamentally alleviate potential MRV challenges under the Methane Regulation.
- ▶ **Impact of Methane Regulation on emissions:** the improved MRV of methane emissions combined with the emissions mitigation provision stipulated under the Methane Regulation might potentially result in a rapid decrease of methane emissions during the first years of implementation. Therefore, any cap adjustment should take the abatement potential and a

⁴⁵ Ideally, the regulator should define installations in such a way as to fully exploit synergies between current EU ETS 1 definitions and the Methane Regulation, thereby minimizing the bureaucratic burden and ensuring consistency.

more refined MRV system into account. Otherwise, the chosen cap adjustment might result in a lower cap stringency than predicted.

- **Unexpected super-emitting events:** in contrast to regulating CO₂ emissions, the regulation of methane emissions faces uncertainties due to the potential of super-emitting events (Piria & Görlach 2024). In Europe – in contrast to the rest of the world - such events are often associated with accidents or other abnormal causes (i.e., they are non-routine releases) and would result in an unexpected increase in cap stringency. Even though such events are rare in Europe (with the notable exception of the intentional attack on the Nord Stream pipeline in 2022⁴⁶), regulators might want to exclude such events from historic emissions when calculating the cap. Additional rules might be necessary to require operators to insure against these additional compliance costs or even exempt such events from the pricing mechanism (Piria & Görlach 2024).

5.2 Design options for the inclusion of methane emissions in the EU ETS 1

The inclusion of methane under the EU ETS 1 could be achieved in several ways. This subchapter presents four different design options and discusses the strengths and weaknesses of each approach. The design options are structured along two key dimensions: emissions MRV and scope (see Table 3). In terms of emissions MRV, operators of installations along the supply chain could report emissions in two different ways:

1. calculate methane emissions based on default factors referenced to the mass of natural gas extracted or transported⁴⁷; or
2. build on the Methane Regulation and include methane emissions as reported under the planned MRV framework, which will be equivalent to OGMP 2.0 Level 5.

In terms of scope, we highlight two potential options:

- a. only including methane emissions arising from natural gas extraction; or
- b. including all methane emissions along the full supply chain of natural gas.

Table 3 Design options for methane emissions inclusion in the EU ETS 1

		Scope	
		Natural gas extraction	Full natural gas supply chain
MRV	Default factors	Option 1A	Option 1B
	Based on Methane Regulation	Option 2A	Option 2B

5.2.1 Comparison along MRV dimension

Accuracy uncertainty

A core assumption of the EU ETS 1 is that every allowance certificate reflects the emission of exactly one tonne of CO₂e into the atmosphere. A crucial requirement of such a system is, therefore, the exact quantification of emissions across space and over time. However, both

⁴⁶ See <https://www.theguardian.com/business/2025/nov/03/the-nord-stream-riddle-echoes-of-mistrust-ripple-through-europe> (accessed November 30th, 2025)

⁴⁷ The reporting obligation is thereby with the operators extracting or transporting natural gas.

Option 1 and Option 2 entail important uncertainties regarding whether the same high levels of accuracy and MRV integrity for inclusion in the EU ETS 1 can be achieved.

Assuming a complete and timely roll-out of the EU Methane Regulation until the beginning of the fifth EU ETS 1 trading period in 2030, the resulting MRV infrastructure would provide the first comprehensive data source on methane emissions in the EEA. However, Chapter 3.2 has highlighted that important uncertainties remain regarding the level of accuracy of the reported emissions, as the development of such a complex MRV framework will inevitably face technical and political challenges. These might potentially result in a delayed implementation timeline or a reduction in the expected quality of the provided emissions data. It is at this early stage unclear whether these uncertainties will be successfully resolved to the extent that would allow the inclusion of the reported methane emissions into the EU ETS 1.

The alternative use of default factors would not alleviate this concern, as they would, by design, only approximate methane emission levels. Given the important variation in methane emissions depending on asset maintenance and the operator's behaviour, default factors cannot ensure the equivalence of allowances covering methane emissions under the EU ETS 1.

Abatement incentives

Methane abatement incentives at stationary installations depend on data accuracy. A more precise and dependable MRV system yields higher abatement incentives. For example, operators have higher incentives to avoid and address methane leaks if doing so reduces their reported methane emissions under the EU ETS 1. Including methane emissions into the EU ETS 1 based on default factors would remove this incentive. Emissions costs would then be higher for efficient plants and lower for inefficient plants compared to a scenario with precise MRV.

Efficient abatement incentives for operators will only materialise if methane emissions are included based on actual values, as set out in the MRV framework envisaged by the EU Methane Regulation (Option 2). However, both Option 1 and 2 would translate into a realignment of incentives further down the supply chain as long as abatement costs and emissions costs are passed through to the final consumer (e.g., for the production of hydrogen).

Regulatory implementation costs

Both options would imply an update to the MRV Implementing Regulation. Option 1 would be consistent with the inclusion of methane emissions from ship engines in the EU ETS 1, which are also calculated based on default factors (see Section 3.3). However, these emissions constitute methane slip, which is easier to estimate than diffuse methane emissions from sources such as leaks. Defining a whole range of methane default factors per supply chain segment in Option 1 would be a technically highly complex endeavour that could additionally be challenged by the affected industrial actors.

These questions could be circumvented under Option 2, as regulators could refer to the MRV framework provided by the Methane Regulation under the assumption that both are sufficiently aligned. However, Option 2 is associated with the additional costs of enforcing the correct application of the complex MRV requirements under the Methane Regulation, which would not be necessary under Option 1.

5.2.2 Comparison along scope dimension

Environmental effectiveness

By including all elements in the natural gas supply chain, Option B increases the quantity of priced methane emissions compared to Option A. However, quantifying this difference and,

therefore, approximating the impact on environmental effectiveness is challenging. Based on data from the IEA Methane Tracker, supply chain methane emissions emitted in the EEA are mostly coming from gas pipelines and LNG facilities (70%), while extraction only accounts for 30% of methane emissions within the EEA (see Figure A.4). Option A would therefore only cover a relatively small fraction of methane supply chain emissions emitted in Europe.

However, the estimates from the IEA Methane Tracker are prone to high uncertainties. In addition, the current estimates do not take into account the changes in the relative importance of methane emissions in Europe across supply chain segments that might materialise in the wake of the Methane Regulation. It is therefore difficult to reliably quantify the difference in coverage between Option A and B.

Stakeholder acceptance

Stakeholder acceptance will not only depend on the scope definition, but also on the alignment between the scope of methane emissions in the EU ETS 1 and CBAM, as is the case for sectors in the current CBAM scope. Assuming such an extension of the CBAM and given a lower expected methane intensity of European natural gas, stakeholders will likely support Option B and a full supply chain methane pricing under the EU ETS 1. Moreover, if focusing on a wider circle of stakeholders, acceptance also depends on additional factors such as price pass-through to energy consumers and competitiveness concerns. Measures to deal with such challenges, such as a gradual phase-in and/or use of free allocation, are not discussed in this paper as they clearly go beyond its scope.

Regulatory implementation costs

Increasing the share of supply chain methane emissions to be included under the EU ETS 1 inevitably increases the number of actors being regulated and the efforts associated with MRV. On the one hand, assuming an MRV framework based on default values would require political and technical discussions on the definition of those factors. This is especially relevant under Option 1B, where the number of regulated actors is larger. However, the OGMP L3 framework already offers a methodology for defining and applying methane emissions default values. Nevertheless, even though agreeing to such an already established methodology would minimise regulatory implementation costs, increasing the number of regulated entities also increases the risk that affected stakeholders challenge these default values. On the other hand, in a setting where emissions are monitored based on the Methane Regulation's MRV framework, the proper enforcement of the system would need to be ensured for an increased number of installations.

5.3 Concluding remarks on supply chain emissions pricing in the EU ETS 1

This chapter has presented four different options to include supply chain methane emissions emitted inside the EEA in the EU ETS 1. Based on this analysis, we draw the following conclusions:

- ▶ **Scope dimension:** supply chain emissions emitted in the EEA are a small share of total supply chain emissions of natural gas consumed in the EU. The additional environmental effectiveness of pricing the full supply chain in the EEA, compared to only the natural gas extraction segment, is limited. The main policy instrument in this context is the CBAM (see next chapter). However, inclusion of a new sector under CBAM presupposes analogous inclusion under the EU ETS 1. Against this backdrop and from a climate impact viewpoint, the extension of the EU ETS 1 with a subsequent, and aligned extension of the CBAM can be deemed the most effective.

- ▶ **MRV dimensions and integrity of the EU ETS 1:** an inclusion of methane emissions in the EU ETS 1 presents substantial concerns in terms of accurate MRV. At the moment, the exact equivalence of allowance certificates, crucial for any ETS, cannot be guaranteed, neither under the MRV framework of the Methane Regulation nor under an MRV framework relying on default values. In addition, both options would have important costs in terms of regulatory implementation. Finally, relying on default values would reduce abatement incentives.
- ▶ In the future, the data accuracy of the estimates provided under the MRV framework of the Methane Regulation might prove to meet the required quality standards under the EU ETS 1. In that scenario, an inclusion of methane emissions in the EEA based on the Methane Regulation for the full supply chain should be reassessed, especially if coupled with an analogous extension of the CBAM mechanism.

6 Pricing supply chain emissions outside the EEA in the CBAM

As previously discussed, supply chain emissions emitted outside the EEA represent a large share of total supply chain emissions of natural gas consumed in Europe, but are not subject to emissions pricing. In order to price these supply chain emissions of imported natural gas, they could potentially be included in the carbon border adjustment mechanism (CBAM), given that pricing of domestic supply chain emissions is implemented via an extension of the EU ETS 1. This would avoid carbon leakage and level the playing field between actors along the supply chain within and outside the EEA.

The CBAM has just entered its definitive phase (January 2026) and is currently limited to 5 sectors producing basic products - iron and steel, aluminium, cement, fertilisers and hydrogen as well as electricity.⁴⁸ The CBAM will be gradually phased in for these sectors over a period from 2026 to 2034. However, Recital 67 of the CBAM Regulation (EU) 2023/956 states the aim that all sectors covered by the EU ETS Directive should also be included in the CBAM by 2030.

The CBAM is designed to be compatible with WTO rules and, thus, respects the principle that imported products are not less favourably treated than those produced within the EU.⁴⁹ Therefore, only those emissions that are covered by the EU ETS 1 in the EEA can be covered by the CBAM.

6.1 Inclusion of natural gas supply chain in the CBAM scope

6.1.1 CO₂ emissions

Natural gas supply chain CO₂ emissions emitted in Europe are already covered under the EU ETS 1 (see Chapter 3). Therefore, a CBAM scope extension to natural gas and LNG covering the respective supply chain CO₂ emissions emitted outside of Europe would generally be compatible with WTO rules.

Under the definitive CBAM regime, importers can report actual emissions values or make use of default factors as a fall-back option. This framework could be applied to supply chain CO₂ emissions. In case importers were to opt for default values, these default values could be the same for any natural gas imported into the EEA, or be based on country-level estimates of supply chain CO₂ emissions, or only differentiate between pipeline and LNG transport, regardless of the country of origin. This latter option would capture the additional CO₂ emissions arising in the LNG transport chain (particularly at liquefaction plants), but would not be able to differentiate between different CO₂ intensities of natural gas extraction across countries. Finally, it would be important to exclude CO₂ emissions arising during LNG shipping, as these are already (partially) covered in the EU ETS 1.

CO₂ is emitted along the full natural gas supply chain, but is particularly concentrated at the segment of natural gas liquefaction for LNG. Given that this segment plays a negligible role inside the EEA, direct emissions leakage caused by the relocation of liquefaction plants or investment

⁴⁸ The selection of sectors covered by the CBAM to date was based on a combination of the criteria of CO₂ intensity and trade intensity (Recital 31, CBAM Regulation). The assessment was based on the current scope of the emissions covered. While the extraction of crude oil as well as the mining of hard coal are sectors included in the Carbon Leakage List valid for the 2021-2030 period, natural gas extraction is not included in the list. Commission Delegated Decision (EU) 2019/708 of 15 February 2019 supplementing Directive 2003/87/EC of the European Parliament and of the Council concerning the determination of sectors and subsectors deemed at risk of carbon leakage for the period 2021 to 2030: https://eur-lex.europa.eu/eli/dec_del/2019/708/oj

⁴⁹ Recital 29, CBAM Regulation (EU) 2023/956.

leakage is not a major concern.⁵⁰ However, pricing supply chain CO₂ emissions outside the would still achieve the important goal of disseminating the carbon price signal and ensuring a level playing field in all potential downstream markets, including the ones for blue and green hydrogen.

6.1.2 Methane emissions

As outlined in Chapter 3, natural gas supply chain methane emissions emitted in Europe are not covered under the EU ETS 1, and including them would pose significant challenges (see Chapter 5). However, a corresponding extension to the scope of the EU ETS 1 is a prerequisite for including supply chain methane emissions in the CBAM, and therefore the pricing of such methane emissions originating in third countries.

The inclusion of methane into CBAM would come with analogous options to the ones presented in Table 3. Supply chain methane emissions outside the EEA could be included in CBAM for the whole supply chain or only for natural gas production, and emissions could be reported based on the reporting framework of the Methane Regulation or on default values, potentially varying by country of origin.

If a CBAM inclusion were to be restricted to methane emissions of natural gas production, it could rely on the actual emissions provided under the Methane Regulation's provisions for methane intensity values for all imported natural gas into the EEA (from 2028 on). These emissions will have to be calculated based on the equivalent MRV standards of European methane emissions (see Chapter 3) and, therefore, reflect actual emissions, as per the current CBAM design. However, the accuracy of these values will be even more uncertain than those for EU natural gas actors: in addition to the technical challenges of methane MRV discussed in Chapter 5, the actors required to provide the data – even though the regulation prescribes independent verification by third parties – will be under the jurisdiction of a third country.⁵¹ Discussions around data quality from the Permian – where different producers produce in immediate proximity to each other – tend toward settling at local average emissions as a fall-back to accurate asset-level data in certain locations, because emissions of individual producers cannot be differentiated accurately. It is, therefore, unclear if these methane intensity estimates of production will reflect actual emissions accurately.

The methane intensity values of the Methane Regulation only reflect natural gas production. If CBAM inclusion were to additionally reflect emissions from all remaining supply chain segments, or if the data quality provided by the MRV framework of the Methane Regulation for production emissions is deemed unsatisfactory, default factors could be used. Until now, the use of default factors is foreseen as a fall-back approach to limit the administrative burden of CBAM. However, given the challenges to precisely monitor methane emissions, the use of default values could be considered, particularly for the starting phase of methane inclusion into the CBAM. This would require a change to the CBAM regulation.

As already addressed in Chapter 5, pricing actual supply chain emissions instead of emissions estimated with default factors has two effects. On the one hand, it incentivises producers to reduce their own emissions and invest in abatement technologies. On the other hand, the price signal should be passed through along the supply chain and reach the end-user of the natural gas, thereby ensuring a level playing field in downstream markets. Using default factors instead

⁵⁰ The Hammerfest liquefaction plant in Norway is the only major liquefaction plant in the EEA.

⁵¹ Discussions around data quality from the Permian (where different producers produce in immediate proximity to each other) tend toward settling at local average emissions as a fall-back to accurate asset-level data in certain locations, because emissions of individual producers cannot be differentiated accurately.

of actual emissions mutes the first mechanism and focuses on putting a price signal on end-users and ensuring a level playing field in downstream markets.

6.2 Concluding remarks on supply chain emissions pricing under CBAM

Natural gas supply chain emissions outside the EEA represent a large share of the total supply chain emissions of natural gas consumed in the EEA and are not subject to a price signal. Future scope extension of the CBAM could be an instrument to address this issue. Based on the previous analysis, we make the following conclusions:

- ▶ Pricing supply chain CO₂ emissions originating outside the EEA by including natural gas in the CBAM scope could have positive climate impacts and is associated with comparatively low additional costs. Such an extension would both reduce the carbon leakage risk and additionally help propagate the carbon price signal in downstream markets.
- ▶ Including supply chain methane emissions outside the EEA under CBAM would have important climate impacts, but is only possible under a scope extension of the EU ETS 1. If in the future the data requirements for such an EU ETS 1 scope extension reach the required accuracy standards, the analogous inclusion of methane into the CBAM could be pursued.

7 Implications of supply chain emissions pricing

From a climate policy perspective, implementing supply chain emissions pricing through the EU ETS 1 and CBAM as outlined above could realign economic incentives across the supply chain and establish an economically efficient role of natural gas as a transition fuel. In particular, it might result in higher climate impact than the maximum methane intensity values due by the end of the decade under the Methane Regulation, as these thresholds would only apply to new contracts and their exact level must yet be decided. However, the affected economic actors might be exposed to economic and/or social impacts. In this chapter, we outline which sectors might be most affected and what level of price increases might be expected from complete supply chain emissions pricing.

The economic effects would be channelled through the consequences on electricity production and storage, and heat production. Given an emissions pricing start by the end of this decade, we would expect natural gas to still play an important role as marginal price-setting technology in European electricity markets. However, the relevance of natural gas in these markets is expected to steadily decrease as renewables and demand flexibility options expand. The economic effects through increased electricity prices are therefore likely to be smaller than effects derived from heat production, a sector that is expected to take longer to decarbonise. These effects might be relevant for industry insofar as a realignment of incentives from direct natural gas combustion and blue hydrogen towards green hydrogen materialises. In addition, households relying on gas boilers for heating might also be exposed to economic and social consequences to the extent that decarbonised heating systems are not comprehensively available, which is likely to be the case at least during the first years of the coming decade.

The extent of these economic and social costs is primarily driven by the cost increases implied by supply chain emissions pricing. However, calculating these increases presents three main challenges. First, it is challenging to estimate the current baseline level of supply chain emissions and, with it, the direct impact of carbon pricing for regulated entities. Second, the pass-through of costs along the supply chain might vary and will not always be equivalent to full pass-through. Third, pricing will lead to emissions abatement at lower costs than the emissions price, but estimating this effect *ex ante* in a thoroughly substantiated way goes beyond the scope of this study. A whole range of secondary effects, including changes to the energy mix and the composition of EU suppliers, add an additional layer of complexity to these calculations. These challenges imply that any quantification must rely on uncertain assumptions and be interpreted extraordinarily carefully. Nevertheless, we present an approximation of the resulting price increases due to supply chain emissions pricing. We do so separately for CO₂ and methane supply chain emissions at a hypothetical emissions price of 100 Euro per tCO₂e (2800 Euro per tCH₄), which is assumed to be fully passed onto output prices.

In the case of CO₂, we focus on the effect of pricing supply chain emissions outside the EEA, as emissions inside the EEA are fully priced under the EU ETS 1. We additionally assume that pricing will not lead to a change in the share of imported gas into the EEA and will have no effect on emissions abatement. These assumptions would only be justified under small price impacts or a lack of technological/supplier alternatives. Under these assumptions and a weighted average CO₂ intensity of natural gas imports into the EEA of 15 gCO₂/MJ (in line with Figure 3), including CO₂ supply chain emissions into CBAM mirroring their current inclusion in the EU ETS 1 would result in a cost increase of 5 Euro per MWh of imported natural gas. Assuming a share of

55% imported natural gas in total EEA gas consumption, this would translate into an increase of 2.70 Euro per MWh for the final European consumer.⁵²

The analogous calculation for methane supply chain emissions is considerably more complex. First, baseline emission intensities as reported in Figure 3 are subject to higher levels of uncertainty than CO₂ emissions. In addition, an important share of methane emissions is estimated to have low abatement costs. As a consequence, supply chain methane intensities at the beginning of the coming decade might have decreased substantially compared to today due to leak detection and repair mandates in Europe and the future maximum methane intensity thresholds stipulated by the Methane Regulation to start by the end of the decade. Finally, methane pricing might drive additional abatement of harder-to-abate methane emissions below the upcoming maximum threshold or for natural gas with legacy contracts not subject to this maximum threshold. Given this uncertainty, we assume methane intensities to end up between 3 gCO₂e/MJ and 8 gCO₂e/MJ under GWP 100 (0.1 and 0.27 gCH₄/MJ), both in Europe and internationally. Pricing these methane emissions under the EU ETS 1 and CBAM and holding all other assumptions from the above calculations constant would result in a cost increase of 1 to 2.60 Euro per MWh of natural gas.⁵³

The combined effects of CO₂ and methane pricing might therefore result in a price increase of between 3.70 and 5.30 Euro per MWh, depending on the assumed methane intensity. The economic relevance of this hypothetical price increase might depend on the total counterfactual natural gas price, which varies across economic agents and countries. Assuming a representative EU household faces costs of 100 Euro per MWh of natural gas net of taxes⁵⁴, this would imply a price increase of about 3.7-5.3%.⁵⁵ However, we can only reiterate the complexity of this analysis and the uncertainty of the underlying assumptions. Should a carbon price on supply chain emissions of natural gas be implemented in the EU, we leave it to future research to analyse the remaining question of what flanking social or economic measures might be warranted.

⁵² These calculations are based on a CO₂ price of 100 Euro, a CO₂ supply chain intensity consistent with Figure 3 of 15 gCO₂/MJ and a share of imported natural gas resulting from Table A.4. A change in these input parameters would alter the resulting cost estimates.

⁵³ These calculations are based on a CO₂ price of 100 Euro and a methane supply chain intensity consistent with Figure 3. A change in these input parameters would alter the resulting cost estimates.

⁵⁴ See https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Natural_gas_price_statistics (accessed July 31, 2025)

⁵⁵ This increase does not include the additional price hikes derived through VAT. Taking into account VAT of e.g. 19% would increase this range to 4.4-6.3%. However, VAT levels on gas consumers vary across EU member states.

8 Conclusions

This report has considered a set of questions around natural gas supply chain emissions, their regulatory framework and options for their potential pricing under the EU ETS 1 and CBAM. Our main findings are as follows:

- ▶ Supply chain emissions from natural gas consumed in Europe differ by country of origin, ranging from less than 3 g CO₂eq/MJ to more than 20 g CO₂eq/MJ. This implies a substantial increase of up to 35% of emissions compared to the mere combustion emissions of natural gas. Both CO₂ and methane emissions contribute to supply chain emissions of natural gas. Their relative contribution varies by country of origin. Due to unreliable methane emissions estimates, the exact level of methane emissions is subject to high levels of uncertainty.
- ▶ If these supply chain emissions remain unregulated, it could have two implications for the energy transition. First, the direct role of natural gas as a transition fuel could be greater than warranted by economic efficiency under proper pricing. Second, this could put green hydrogen (produced via electrolysis using renewable electricity) at a disadvantage compared to gas-based hydrogen (so-called grey or blue hydrogen), since the upstream emissions of these latter products would remain unpriced, making them comparatively cheaper.
- ▶ Most supply chain emissions of natural gas emitted in the EEA are already regulated, and a share of these are already subject to emissions pricing. CO₂ emissions at stationary installations are priced under the EU ETS 1 and potentially EU ETS 2. Methane emissions from stationary installations are beginning to be monitored with the implementation of the EU Methane Regulation, and OGMP 2.0 Level 5 MRV will be requested along the full supply chain in Europe by the end of this decade. CO₂ and combustion-related methane emissions from shipping are partially monitored and priced under the EU ETS 1, although a share of maritime methane emissions is left unregulated.
- ▶ Supply chain emissions emitted outside the EEA do not face a comparable MRV framework under EU legislation, but likely represent a large share of total supply chain emissions. CO₂ emissions outside the EEA are not comprehensively regulated by any policy instrument. In contrast, once the Methane Regulation is implemented, natural gas imported into the EEA will have to report methane intensities of production for new supply contracts from the end of this decade onwards. In addition, the Low-Carbon Fuels Delegated Act provides default factors for supply chain CO₂ and methane emissions of pipeline natural gas.
- ▶ Only a few oil and gas-producing countries have started to monitor and even price supply chain methane emissions. Notably, Norway and Australia have been pricing methane emissions from the oil and gas sector for many years. The USA had briefly introduced a methane tax in 2024 but repealed it in 2025. In Canada, government proposals from 2023 to introduce methane emission monitoring and/or pricing have not been implemented.
- ▶ We conclude that there is room to improve the pricing of supply chain emissions from natural gas consumed in Europe. Any consideration of this issue would have to involve assessing the respective benefits and costs of pricing CO₂ and methane.
 - CO₂ supply chain emissions are already priced within the EEA. A potential regulatory instrument to address CO₂ natural gas supply chain emissions outside the EEA would be an expansion of CBAM to reflect analogous coverage as inside the EEA. Such a CBAM extension would provide important climate benefits both in terms of leakage prevention

and price signals in downstream markets. It would require setting up an MRV framework for actual emissions in third countries or, in addition, allowing for default values to be used.

- The pricing of supply chain methane emissions presents more challenges than for CO₂ supply chain emissions, in particular due to the additional complexity of methane emissions MRV. The Methane Regulation will provide a first MRV framework for emissions within the EEA. However, it is unclear if the level of accuracy of this framework will meet the requirements of the EU ETS 1, which heavily relies on the principle of “a tonne is a tonne”. Against this backdrop, it would be advisable to first gather experience on the accuracy and administrative costs of the Methane Regulation data estimates. On that basis, an assessment of the suitability of the EU ETS 1 to price methane supply chain emissions can be carried out.
 - If the estimates provided by the Methane Regulation inside the EEA prove to meet the required standards of the EU ETS 1, we find that a scope extension of the EU ETS 1 would be best combined with an analogous extension of the CBAM coverage. Such a CBAM extension could rely on the methane emissions estimates under the Methane Regulation or allow for the use of default factors.
- Supply chain emissions pricing is likely to increase the price of natural gas. However, quantifying this impact is highly complex and subject to important uncertainties. Based on a set of assumptions, the total price impact is roughly estimated to range between Euro 3.70 and 5.30 per MWh, depending on the assumed methane intensities and assuming a carbon price of 100 Euro per tCO₂e. Pricing only CO₂ emissions analogously to their coverage under the EU ETS 1 would result in a price impact of Euro 2.70 per MWh.

Pricing supply chain emissions is only one of the potential policy instruments to address and reduce them. Given the complexity of methane MRV and the resulting challenges for methane emissions pricing, as well as the complex timeline of the required EU legislative process, additional policy instruments such as the Methane Regulation and the Low-Carbon Fuels Delegated Act are important and potentially effective policy alternatives.

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A Appendix

A.1 Extension of supply chain emissions pricing to crude oil

This report focuses on the pricing of supply chain emissions from natural gas given its crucial importance during the upcoming energy transition. However, an extension to other energy carriers, and in particular crude oil, is possible. Such an extension could have a sizeable climate impact. In this context, the following aspects should be taken into account:

- ▶ As for the case of natural gas, the supply chain CO₂ emissions of oil emitted inside the EEA are already under the EU ETS 1. An extension of CBAM to supply chain CO₂ emissions outside the EEA would, therefore, be unproblematic from a WTO point of view.
- ▶ From a methane data requirement perspective, pricing supply chain methane emissions from oil would work analogously to natural gas. Both energy carriers are subject to the same regulatory framework under the EU Methane Regulation. Therefore, oil will be subject to the same MRV standards if produced in the EEA and the same requirements on importers if produced outside the EEA. As a consequence, the same challenges regarding methane MRV that apply to natural gas also apply to oil.
- ▶ Pricing supply chain emissions for oil and gas would allow for a level playing field during the upcoming energy transition between these two energy carriers, but also in comparison to low-carbon alternatives. Pricing supply chain emissions of oil would additionally impact downstream markets and reach the final consumer, e.g. at petrol stations. It could, therefore, be an additional driver to influence purchasing decisions and incentivise transport decarbonisation.

A.2 Natural gas imports

Table A.4 Natural gas imports into the European Union in 2023 (bcm)

Country of origin	LNG imports	Pipeline imports	Total imports
Norway	5	90	95
USA	63	0	63
Russia	18	27	45
Algeria	10	33	43
Qatar	17	0	17
Azerbaijan	0	12	12
Nigeria	9	0	9
Trinidad and Tobago	4	0	4
Angola	3	0	3

Country of origin	LNG imports	Pipeline imports	Total imports
Libya	0	3	3
Egypt	2	0	2
Total	131	165	296

Source: Bruegel (2024) available under: <https://www.bruegel.org/analysis/future-european-union-gas-imports-balancing-different-objectives>

Note: EU production amounted to 38 bcm. Only countries exporting at least 2 bcm are included in the list. Imports from the UK are not included.

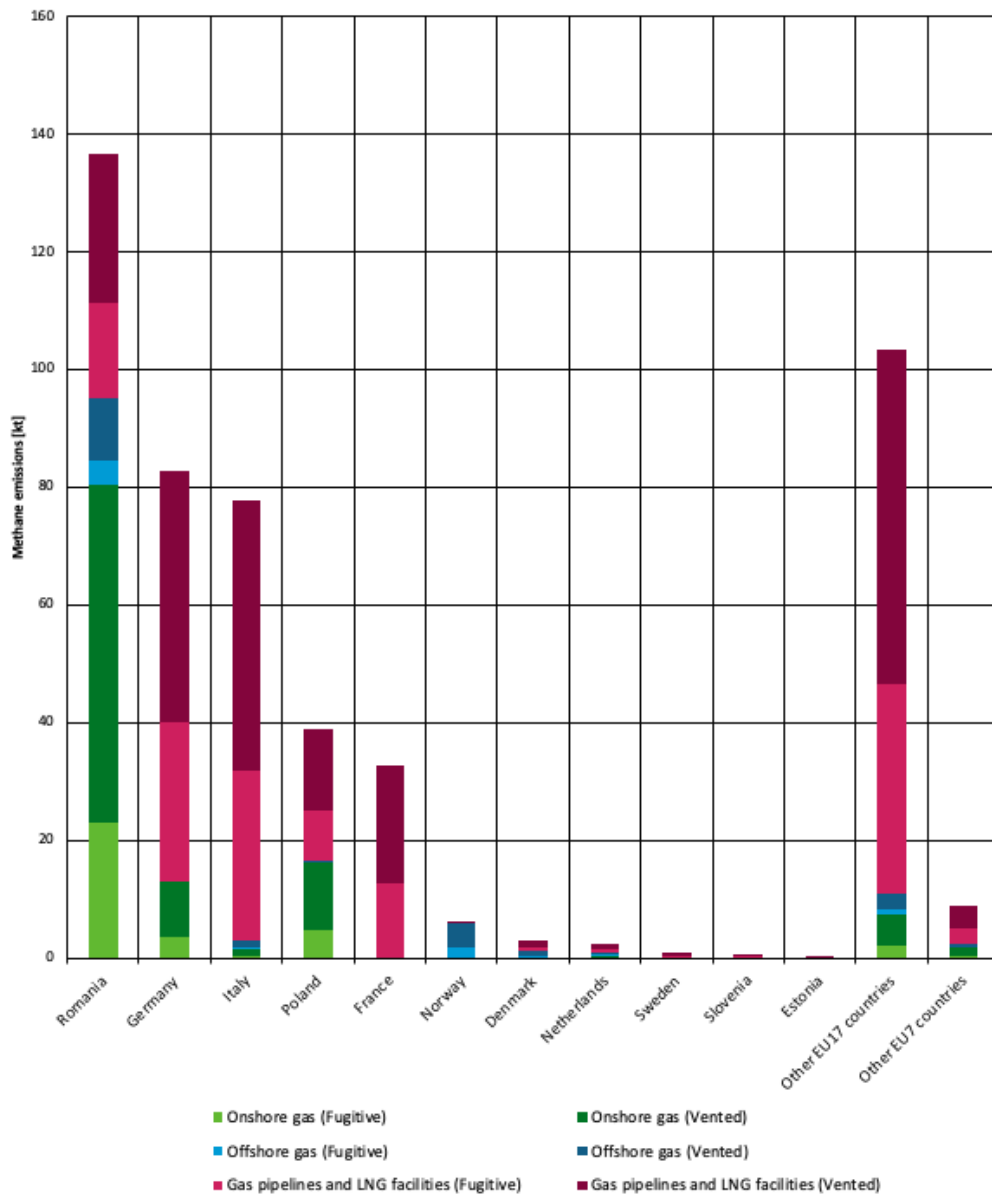
A.3 Geographical distribution of energy-sector methane emissions in the EU

Figure A.4 presents energy-sector methane emissions estimates as provided by the International Energy Agency’s Methane Tracker, which currently provides the best harmonised estimates on this matter.⁵⁶ The methodology applied only differentiates between three production stages (onshore gas production, offshore gas production and emissions from gas pipelines and LNG facilities) and provides different estimates for vented and fugitive emissions. In terms of geographical granularity, the Methane Tracker focuses on countries with the largest emissions, while the remaining countries are not quantified separately. Three main aspects are worth noting. First, methane emissions only play a significant role in a handful of countries, with only five countries emitting more than 20 kt CH₄ a year. Second, emissions across Europe mainly occur in gas pipelines and LNG facilities, while emissions from onshore and offshore production represent a much smaller share of total emissions. Third, Romania stands out with the highest amount of absolute methane emissions. This is driven by a particularly high estimate for vented and fugitive emissions in the onshore production stage.

Two important caveats regarding these numbers should be considered. First, the inaccuracy of these estimates might be substantial. Even though the International Energy Agency’s Methane Tracker is currently the best source for reliable methane emissions estimates, their uncertainty should not be disregarded. The new reporting standards under the Methane Regulation for assets in the EU will considerably increase the accuracy of methane emission estimates. Second, the Methane Regulation also introduces methane mitigation requirements. In particular, it introduces new Leak Detection and Repair Obligations, a ban on routine flaring and limits on venting. All these requirements are likely to decrease methane emissions in Europe, although the degree to which this will be the case is still uncertain.

⁵⁶ This dataset is publicly available under <https://www.iea.org/data-and-statistics/data-tools/methane-tracker-data-explorer> (accessed Oct. 15, 2024).

Figure A.4 Methane emissions by European country in 2023



Notes: Other EU17 countries: Latvia, Lithuania, Austria, Belgium, Czech Republic, Finland, Greece, Hungary, Ireland, Luxembourg, Portugal, Slovakia, and Spain. Other EU7 countries: Bulgaria, Croatia, Cyprus, and Malta. Data is subject to high uncertainty and real values might be smaller or larger than these estimates.

Source: International Energy Agency – Methane Tracker (2024). Country groups follow the IEA Methane Tracker categorisation.