Assessing Emissions from LNG Supply and Abatement Options

International Energy Agency

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Introduction

Global liquefied natural gas (LNG) supply has grown faster than overall natural gas demand in recent years. Around 580 billion cubic metres (bcm) of natural gas were exported as LNG in 2025, equivalent to about 13% of global natural gas consumption. LNG's share of the gas market is set to increase further, with a wave of new projects coming online over the next several years.

Previous International Energy Agency (IEA) analysis found that greenhouse gas (GHG) emissions from extracting, processing and transporting natural gas through pipelines, and as LNG, are globally on average around 11.5 grammes of carbon dioxide equivalent per megajoule (g CO_2-eq/MJ). Given that about 55 g CO_2/MJ are emitted when natural gas is combusted, extracting natural gas and bringing it to consumers represents nearly 17% of its life-cycle emissions.

There is a broad range of emissions from extracting, processing and transporting natural gas. Due to the high energy requirements to liquefy and transport gas over long distances, LNG tends to have higher emissions than natural gas produced close to where it is consumed. Emissions from gas transported by pipeline also vary widely, often in proportion to the distances involved.

Several importing countries are increasing their efforts to assess the emissions intensity of oil and gas imports through different approaches, such as the EU Methane Emissions Reduction Regulation (EU MER) and the Coalition for LNG Emissions Abatement toward Net-zero (CLEAN).

Producer-side measurement and reporting frameworks such as the Oil and Gas Methane Partnership (OGMP 2.0) are bringing greater visibility and structure to emissions tracking. Reporting and availability of natural gas value chain emissions data have increased significantly in recent years, but estimates remain highly uncertain.

Building on previous IEA work looking at GHG emissions from all sources of natural gas, at the LNG Producer Consumer Conference (LNGPCC) 2024, the Japanese Ministry of Economy, Trade and Industry (METI) and the IEA launched a two-year work programme to look in detail at emissions from LNG supply and abatement options. An interim report was published in 2025, with this final version prepared to inform dialogue at LNGPCC 2026.

This report provides estimates of emissions from LNG supply in 2025, based on the latest and best available production data and estimates from scientific studies and measurement campaigns.

Chapter 1 provides estimates of emissions from natural gas production and processing, pipeline transmission to export terminals, liquefaction, shipping and regasification at import terminals. It considers energy consumption, methane emissions, flaring and naturally occurring sources of CO_2.

Chapter 2 explores mitigation options, including pathways to reduce methane emissions and flaring, improve efficiency across the LNG value chain, electrify key processes and deploy carbon capture, utilisation and storage (CCUS).

Chapter 3 discusses the policy and finance frameworks that can support emissions reductions along the LNG supply chain.

This report does not assess emissions from gas distribution after regasification, end-use combustion, avoided or additional emissions from fuel switching to or from LNG, or emissions associated with other potential LNG sources (e.g. biomethane or e-methane).

Box 1 What has changed since the interim report published in 2025?

In June 2025, the IEA released an interim report that provided estimates of emissions from the LNG supply chain and associated abatement options for 2024. Several changes since then are reflected in this report, including the addition of 2025 data and new scientific and measurement studies.

LNG exports in 2025 were around 30 bcm higher than in 2024, driven by capacity additions in the United States (Corpus Christi Stage 3 and Plaquemines LNG). New LNG producers also entered the market, including Canada (LNG Canada), Mexico (Fast LNG Altamira), Mauritania and Senegal (through the shared Greater Tortue Ahmeyim floating LNG facility).

Several new studies have been published since the interim report, including Pandey et al. (2026), Zhang et al. (2026), Zhu et al. (2025) and Ma et al. (2025). Updates from the IEA's Global Methane Tracker, the addition of real-world shipping emissions data from the European Union Monitoring, Reporting and Verification (MRV) database, and an update to feed gas mapping to liquefaction terminals have also been incorporated.

In this report, we estimate that the global average emissions intensity of LNG from production to regasification is 18.6 g CO_2-eq/MJ of LNG delivered, slightly lower than the value published in the interim report (19.4 g CO_2-eq/MJ of LNG delivered). Further details of changes to the underlying data, methodology and model assumptions are available in the Technical annex.

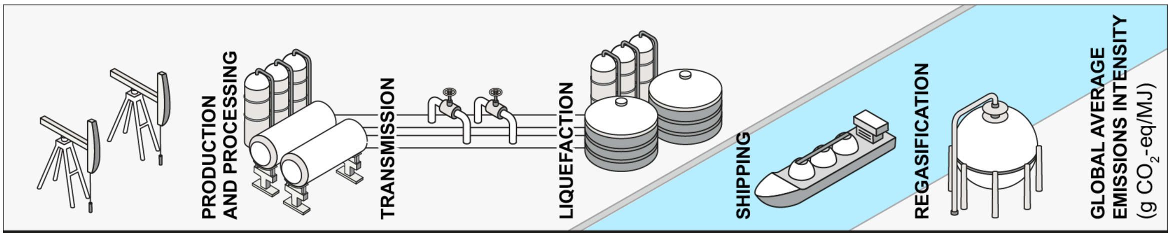
Chapter 1: Estimated emissions from liquefied natural gas

Summary

We provide emissions estimates along the LNG supply chain, covering upstream production, gas processing, transmission, liquefaction, shipping and regasification. The estimates exclude emissions associated with exploration, onward transport after regasification and natural gas combustion.

We analyse feed gas flows from 51 upstream basins in 24 countries that connect to 52 liquefaction terminals in 24 countries and 181 regasification terminals in 50 countries. We track the voyages of 800 LNG carriers making around 7 000 round-trip journeys per year. We compile public and proprietary data on these assets to develop a comprehensive estimate covering the entire supply chain for all deliveries of LNG, from the wellhead through production and processing, transmission to liquefaction facilities, shipping and regasification (Figure 1). Further details of the underlying data, methodology and model assumptions are available in the Technical annex.

Figure 1 Global average emissions from LNG supply by supply chain segment, 2025

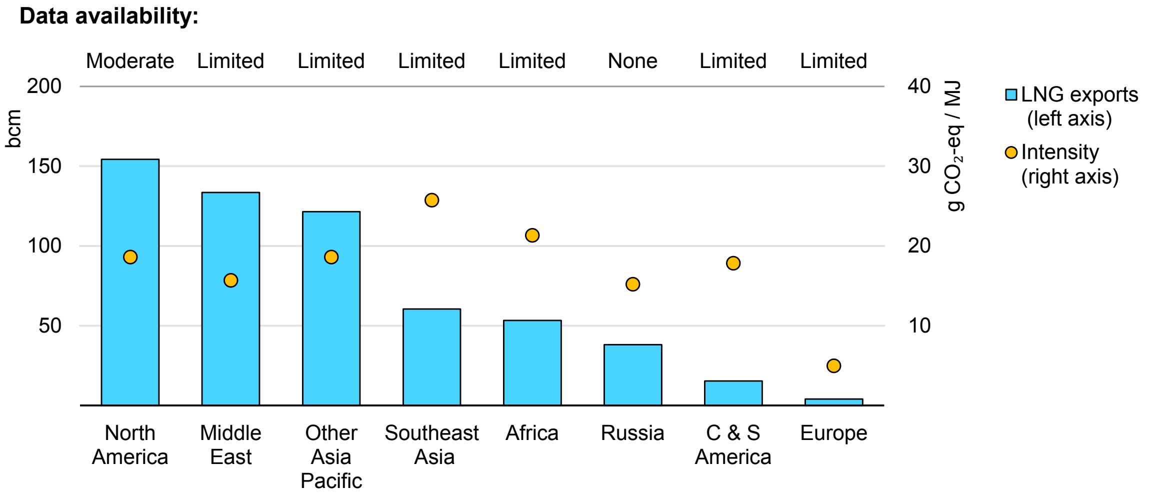


	PRODUCTION AND PROCESSING	TRANSMISSION	LIQUEFACTION	SHIPPING	REGASIFICATION	GLOBAL AVERAGE EMISSIONS INTENSITY ($g\ CO_2$-eq/MJ)
% of supply chain GHG emissions	**40%**	**11%**	**33%**	**15%**	**1%**	**18.6**
% of supply chain CO_2 emissions	**27%**	**11%**	**45%**	**17%**	**1%**	**12.9**
% of supply chain CH_4 emissions	**70%**	**12%**	**6%**	**10%**	**2%**	**5.7**
Key technology levers to lower GHG emissions	**• LDAR • CCUS • Electrification**	**• Electrification • Flow improvements • LDAR**	**• Electrification • CCUS**	**• Low-emissions fuels • Slow steaming • BOG recovery**	**• Low-emissions vaporisers • Cold energy recovery**	

Notes: Intensities are reported as g CO_2-eq per MJ of LNG delivered. GHG = greenhouse gas; CO_2 = carbon dioxide; CH_4 = methane; LDAR = leak detection and repair; CCUS = carbon capture, utilisation and storage; BOG = boil-off gas. Production and processing includes production, gathering and processing. Transmission includes compression and pipeline transport to liquefaction facilities. One tonne of methane is assumed to be equivalent to 30 t CO_2 based on a 100-year global warming potential (IPCC, 2021). Emissions intensities are based on global average figures, but vary by country, basin and supply chain segment. Percentages may not sum to 100% because of rounding.

We estimate total GHG emissions from the LNG supply chain up to and including regasification to be 390 million tonnes of carbon dioxide equivalent (Mt CO_2-eq). Around 70% of these emissions are CO_2, emitted through combustion or venting, while the remaining 30% comes from methane that escapes unburnt into the atmosphere. The main sources of methane emissions are flaring, venting and leakages during upstream production and processing, while the main source of CO_2 emissions is the energy required to compress and liquefy natural gas, followed by upstream production and processing.

Figure 2 LNG exports and estimated average GHG emissions intensity by exporting region, 2025



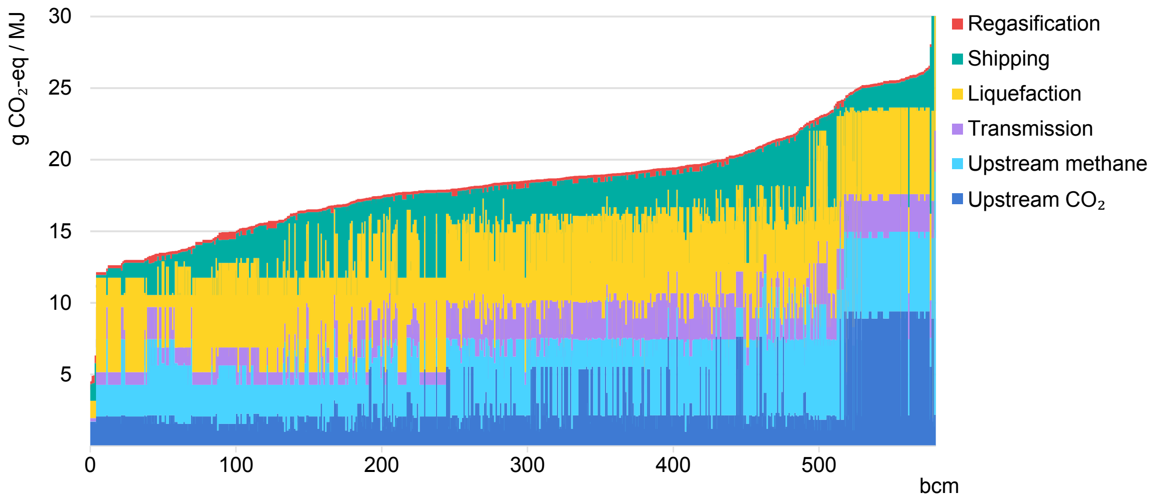
IEA. CC BY 4.0.

Notes: bcm = billion cubic metres; g CO_2-eq/MJ = grammes of carbon dioxide equivalent per megajoule; C & S America = Central and South America. Emissions intensity includes all CO_2 and methane emissions from production, processing, transmission, liquefaction, shipping and regasification, divided by total LNG exports from the region. One tonne of methane is assumed to be equivalent to 30 t CO_2 based on a 100-year global warming potential (IPCC, 2021).

Source: IEA estimates based on scientific literature and the latest available data, including measured, satellite and inferred data. Data availability and quality vary widely across basins, countries and regions. For methane emissions in countries with no data availability, emission intensities are estimated using data from the United States, scaled to account for country- and production-specific factors (see the Technical annex and Global Methane Tracker 2026 Documentation for further information).

Globally, we estimate that the average GHG emissions intensity of delivered LNG is 18.6 g CO_2-eq/MJ, compared with an average of 11.5 g CO_2/MJ for natural gas supply overall. This average masks wide variations across geographies and supply routes, as well as significant differences in data quality and availability across regions. Estimated LNG emissions intensities exceed 20 g CO_2-eq/MJ for some exporters in Africa and Southeast Asia, range from 10 to 20 g CO_2-eq/MJ in North America and the Middle East, and are around 5 g CO_2-eq/MJ in Norway (Figure 2). The variation is explained primarily by the range of methane emissions associated with the natural gas supplied to LNG terminals, energy use during gas transmission and liquefaction, and the level of naturally occurring[1] CO_2 that is vented where dedicated CCUS systems are not in place. In addition, differences in shipping distances and vessel efficiency can lead to substantial variation in shipping emissions intensities across LNG supply routes (Figure 3).

Figure 3 Estimated GHG emissions intensity from the LNG supply chain, 2025



Notes: Each data point represents the estimated weighted average emissions intensity of a single LNG supply route linking an LNG export terminal to a regasification terminal, taking into account round-trip voyages. One tonne of methane is assumed to be equivalent to 30 t CO_2 based on a 100-year global warming potential (IPCC, 2021).

Source: IEA estimates based on scientific literature and the latest available data, including measured, satellite and inferred data. Data availability and quality vary widely across basins, countries and regions. For methane emissions in countries with no data availability, emission intensities are estimated using data from the United States, scaled to account for country- and production-specific factors (see the Technical annex and Global Methane Tracker 2026 Documentation for further information).

Box 2 How do IEA estimates of LNG emissions compare with others?

A wide range of LNG emissions intensities have been reported in the literature, largely driven by differences in process assumptions, system boundaries, allocation methods and emissions quantification approaches (i.e. inventory-based, measurement-based, or a combination of the two). This reflects the inherent complexity of the LNG supply chain, as well as the range of methods available to measure or estimate GHG emissions.

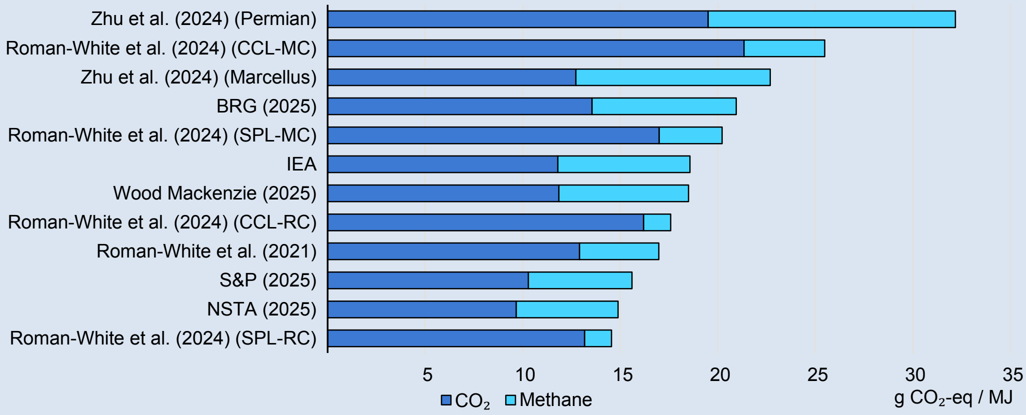
Allocation choices have major implications for overall emissions intensities. Upstream methane emissions can be allocated between co-produced oil and natural gas on an energy or economic basis, or entirely to natural gas on a volumetric basis. Our estimates allocate upstream methane emissions between oil and natural gas on an energy basis.

[1] CO_2 that is extracted with produced natural gas.

There are also different ways to express a tonne (t) of methane in CO_2-eq terms. The most common approach is to use global warming potential (GWP). However, different GWP values can be applied, which has a major impact on the assumed potency of methane. Some studies consider the impact of methane over a 20-year time frame, with 1 t of methane typically assumed to be equivalent to 82.5 t CO_2-eq. Others consider its impact over a 100-year time frame, with 1 t of methane assumed to be equivalent to around 30 t CO_2-eq.[2]

The choice of the most appropriate time frame depends on the emissions scenario in question (e.g. whether or when global temperature rise peaks) and can be subjective. Our estimates assume that 1 t of methane is equivalent to 30 t CO_2.

Figure 4 Emissions from producing and transporting LNG from the United States to Europe reported by different sources



Notes: The basin providing feed gas or the specific US LNG terminal is shown in brackets where specified; otherwise, the estimate represents the average of all US LNG exports to Europe; S&P (2025) does not specify the import location. CCL = Corpus Christi LNG terminal; SPL = Sabine Pass LNG terminal; RC = reference case; MC = measurement-informed case (see Roman-White et al. (2024) for further details). The horizontal axis shows emissions per unit of natural gas delivered to the regasification terminal. The IEA estimate is based on a net calorific value of 49.5 MJ/kg LNG. One tonne of methane is assumed to be equivalent to 30 t CO_2 for all studies. Emissions from end-use combustion are excluded.
Sources: IEA analysis based on Roman-White et al. (2021), Roman-White et al. (2024), Zhu et al. (2024), BRG (2025), North Sea Transition Authority (NSTA) (2025), S&P Global Commodity Insights (2025) © 2025 by S&P Global Inc, and Wood Mackenzie (2025).

When comparing estimates for a specific trade route between the United States and Europe, published estimates for methane and CO_2 emissions from production to regasification range from 14 g CO_2-eq/MJ to 32 g CO_2-eq/MJ (Figure 4). A much higher emissions intensity for LNG trade from the United States to Europe is reported in a debated study by Howarth et al. (2024), at around 56 g CO_2-eq/MJ. When LNG GHG intensities are harmonised across studies using a Lower Heating

[2] Some authors use conversion factors from earlier Intergovernmental Panel on Climate Change assessments. For example, Roman-White et al. (2021), LNG Supply Chains, used a 100-year GWP value of 36 based on the IPCC (2014), AR5 Synthesis Report: Climate Change 2014.

Value basis and a 100-year GWP, the IEA estimates fall within the range of other available estimates.

Even after harmonisation, methane emissions vary more than tenfold among different sources, and CO_2 emissions by a factor of nearly three, highlighting the importance of other methodological factors. For example, using measurement data instead of engineering estimates can change GHG intensity estimates by 41% to 52% (Roman-White et al. (2024)).[3] More work is needed to reconcile these methods. In our analysis, methane accounts for around 35% of the GHG emissions intensity associated with LNG trade between the United States and Europe.

Production and processing

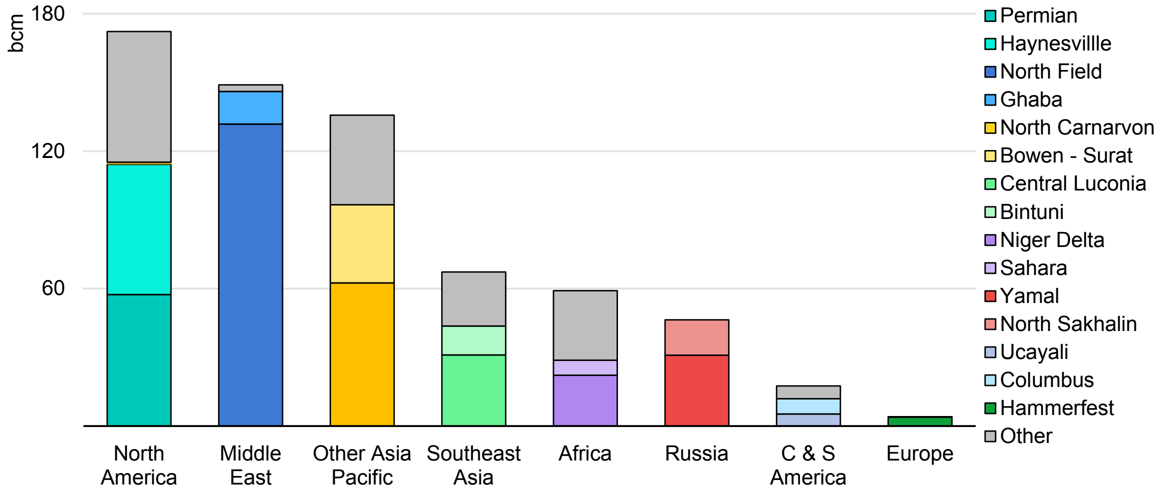
Linking LNG terminals to upstream assets

About 580 bcm of LNG were exported globally in 2025 from 24 countries. 650 bcm of natural gas, usually referred to as feed gas, was produced for these exports, accounting for energy use and losses along the supply chain. Around 50 upstream basins supply feed gas for LNG exports. The gas flows through gathering stations, processing plants, boosting facilities and pipelines before reaching just over 50 liquefaction terminals currently in service globally.

In some cases, it is straightforward to link individual upstream assets to a specific LNG export terminal, for example where there is a single physical connection between them. This is the case in Qatar, where feed gas is supplied from a single gas field, the North Field, and most production is exported as LNG (Figure 5). However, this calculation is more complicated for LNG terminals in the United States. Currently, eight LNG terminals receive natural gas from a pipeline network carrying co-mingled natural gas from multiple upstream assets and processing facilities. In some cases, commercial information, such as producer supply agreements, can shed light on the feed gas that is produced, treated and transported before liquefaction, as can company reports and production data. Nevertheless, different approaches can still be used to trace the origin of feed gas (Box 3). The approach adopted in this work is described in the Technical annex.

[3] Integrating measurement data into supply chain emissions models remains challenging, and best practices for combining measurement and analysis methods are still evolving.

Figure 5 Estimated feed gas volumes to LNG terminals by upstream basin in exporting regions, 2025



Notes: Volumes shown are feed gas and are therefore greater than LNG export volumes because of energy use during liquefaction and other losses along the supply chain. C & S America = Central and South America; Other North America = Appalachian, Barnett, US federal offshore, Williston; Other Asia Pacific = Browse, Clarence-Moreton, Gascoyne, Papua New Guinea Fold belt; Other Southeast Asia = Baram, Balingian, Banggai, Kutai, North Sumatra, Outboard Belt; Other Africa = Berkine, Nile Delta, Reggane, Timimoun; Other C & S America = Trinidad basin.

Sources: IEA estimates based on data from US Energy Information Administration (2025), Federal Energy Regulatory Commission (2025), IEA (2025) World Energy Outlook 2024, Rystad Energy (2025), S&P Global Commodity Insights (2025), S&P Capital IQ (accessed 1 April 2025), and company reporting.

Box 3 Traceability in natural gas supply chains

There has been a surge of interest in understanding how to link specific sources of feed gas to LNG terminals since the introduction of the EU Methane Regulation in 2024. This regulation states that from 2027, importers of fossil fuels (including LNG) must demonstrate that imported fuels comply with EU-equivalent domestic standards for monitoring, reporting and verification of upstream methane emissions. Starting in 2028, importers will be required to report annually on the upstream methane intensity of imported fuels, and from 2030, fuels placed on the EU market are envisaged to be subject to a methane-intensity threshold.

So far, no sector-wide traceability system has been implemented for LNG or natural gas markets. Different models can be used to establish that imported LNG is associated with low or reduced upstream methane emissions. These approaches fall into two broad categories: bundled and unbundled.

In a bundled model, physical supply is directly linked to its emissions attributes. Importers must provide evidence that the specific fuel they have purchased is associated with low upstream methane emissions. A bundled model can be implemented in different ways. For example, operators can use a physical segregation approach, which relies on dedicated infrastructure to keep “low methane intensity" gas separate from higher-intensity gas. This is usually the costliest approach (and often impractical) except where dedicated infrastructure already exists. Alternatively, operators can use a mass balance approach, which allows for mixing of supplies of different intensity but requires that compliance claims correspond to the level of mixing (for example, if 30% of the feed gas is low intensity, the importer can only claim compliance for 30% of the imported supply). Bundled models usually require the implementation of a chain-of-custody system. Existing resources such as the chain-of-custody models established by the International Sustainability and Carbon Certification and the International Organization for Standardization can be used to support bundled approaches. Bundled models can strengthen incentives for emissions reductions but are typically more complex and costly to implement.

In an unbundled model, physical supply is decoupled from its emissions attributes. The most prominent example of an unbundled approach is a book-and-claim system, under which low-intensity producers "book" performance and obtain certificates. Producers then sell these certificates to importers, who can "claim" low-intensity gas even if the physical supply they have purchased is not low-intensity. Book-and-claim models tend to be relatively low-cost and simple for industry but may have lower emissions reduction potential than other models. They also do not allow imported LNG to be traced back to specific upstream assets.

CO_2 emissions from energy use

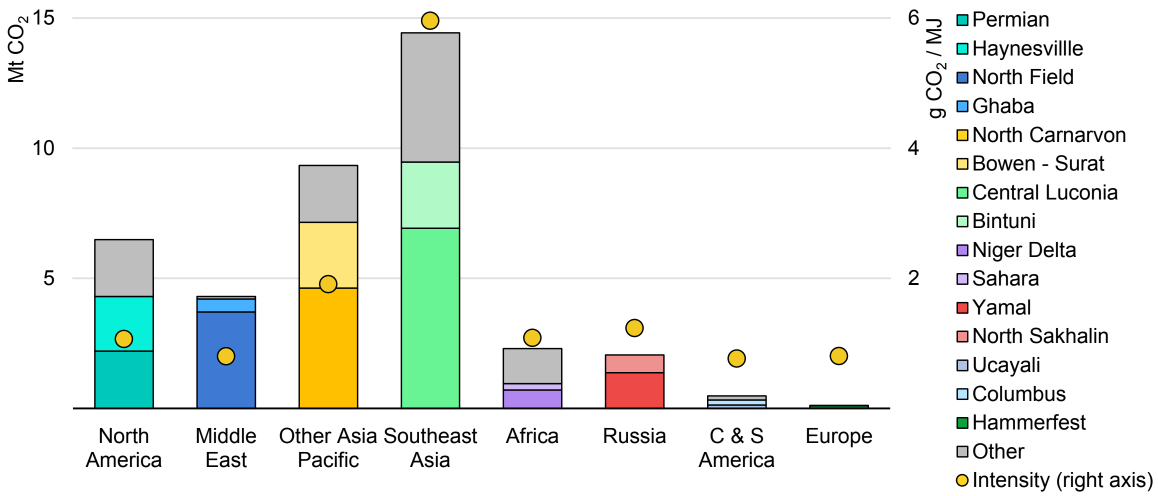
Extracting oil and gas from the subsurface requires large amounts of energy for a brief period to power drilling rigs, pumps and other process equipment, and to maintain the drilling fluids at the required temperature and pressure. A continuous fuel supply is essential for upstream oil and gas operations; typically diesel before production starts (i.e. during the drilling and development stage), and natural gas or electricity during the production phase, although drilling can also be electrified, for example in shale basins. After extraction, natural gas undergoes separation to remove natural gas liquids, dehydration to make it suitable for transport, and treatment to remove impurities such as CO_2, mercury and hydrogen sulphide.

We estimate that the global average emissions intensity of energy used in production and processing is 1.8 g CO_2/MJ of feed gas[4] (Figure 6), although this varies markedly across regions because of differences in the production type, the

[4] In this chapter, emissions intensities are reported either as g CO_2-eq per MJ of feed gas for an LNG terminal or g CO_2-eq per MJ of LNG delivered to regasification terminals, as relevant to the part of the supply chain under study. The global average intensity of 18.6 g CO_2-eq is standardised to MJ of LNG delivered to regasification terminals.

size and maturity of fields providing feed gas, the level of impurities in extracted gas, and the emissions intensity of electricity grids where processes are electrified.

Figure 6 Estimated CO_2 emissions from energy use in feed gas production and processing by basin, and emissions intensity by exporting region, 2025



Notes: C & S America = Central and South America. Other North America = Appalachian, Barnett, US federal offshore, Williston; Other Asia Pacific = Browse, Clarence-Moreton, Gascoyne, Papua New Guinea Fold belt; Other Southeast Asia = Baram, Balingian, Banggai, Kutai, North Sumatra, Outboard Belt; Other Africa = Berkine, Nile Delta, Reggane, Timimoun; Other C & S America = Trinidad basin.

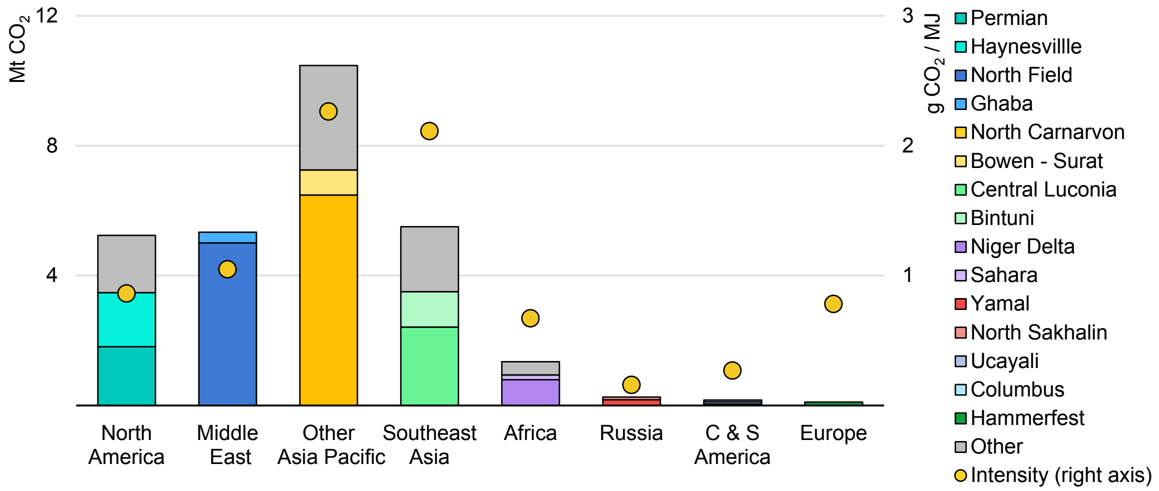
Source: IEA analysis based on the Oil Production Greenhouse Gas Emissions Estimator and annual revisions to energy use for oil and gas extraction (see Technical annex).

Naturally occurring CO_2 emissions

When it is extracted, natural gas often contains CO_2, hydrogen sulphide and heavier hydrocarbon molecules (e.g. butane and pentane). CO_2, hydrogen sulphide and other components are treated or removed (e.g. through amine treatment) to reach specifications for transport; the CO_2 may then be blended, reinjected or vented. Gas streams with higher CO_2 or hydrogen sulphide content (i.e. sour gas) generally require more energy-intensive processing and treatment than sweeter gas compositions, increasing energy use and associated emissions.

Comprehensive datasets on the CO_2 content of natural gas production remain limited. Based on publicly available estimates, we estimate that around 30 Mt of naturally occurring CO_2 is extracted from LNG feed gas each year, of which about 25 Mt CO_2 is emitted to the atmosphere (Figure 7). This corresponds to a global average CO_2 emissions intensity of about 1 g CO_2/MJ of feed gas. However, emissions intensities vary widely across regions, ranging from around 2.5 g CO_2/MJ to less than 0.2 g CO_2/MJ. Around 7 Mt CO_2 of annual capture capacity is currently available worldwide for naturally occurring CO_2 emissions from three LNG plants. In all cases, the captured CO_2 is transported and permanently stored.

Figure 7 CO_2 vented from LNG feed gas by basin and average CO_2 emissions intensity by exporting region, 2025



Notes: C & S America = Central and South America. Other North America = Appalachian, Barnett, US federal offshore, Williston; Other Asia Pacific = Browse, Clarence-Moreton, Gascoyne, Papua New Guinea Fold belt; Other Southeast Asia = Baram, Balingian, Banggai, Kutai, North Sumatra, Outboard Belt; Other Africa = Berkine, Nile Delta, Reggane, Timimoun; Other C & S America = Trinidad basin.

Source: IEA analysis based on field and country CO_2 content (see Technical annex).

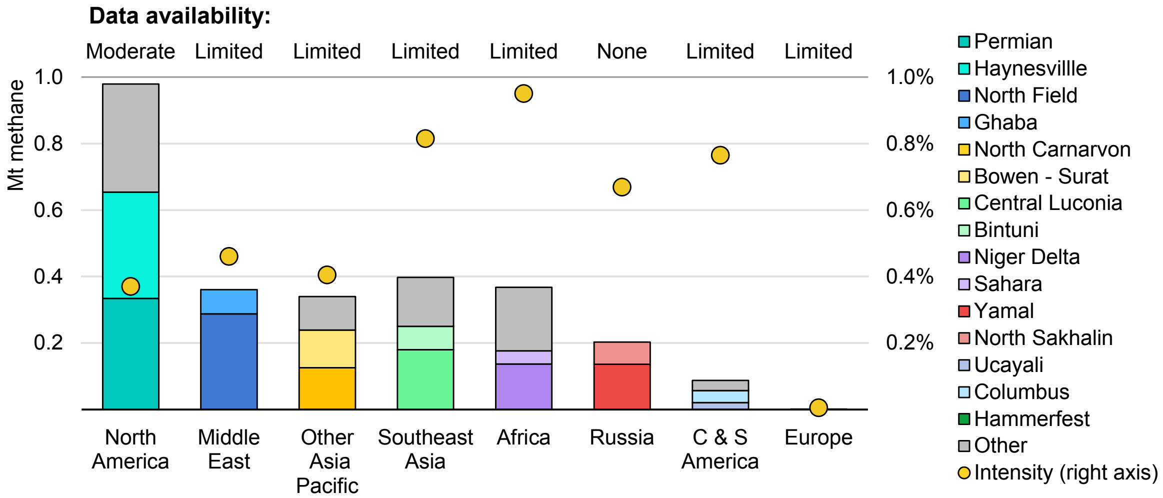
Methane emissions

Sources of methane emissions before liquefaction include emissions from production, gathering and processing; transmission emissions are covered separately. These emissions can result from intentional releases, often due to the design of the facility or equipment (e.g. compressors and valves that vent to the atmosphere), operational requirements (e.g. venting a pipeline for inspection and maintenance) or for safety reasons (e.g. pressure relief valves). They can also result from unintentional leaks, due to a faulty seal or leaking valve, for example, or from the incomplete combustion of natural gas during flaring.

In total, we estimate that around 2.8 Mt of methane was emitted during the production and processing of natural gas that was used as LNG feed gas in 2025 (Figure 8). The global average upstream methane emissions intensity of feed gas was around 0.5% (which translates into average emissions of 3.5 g CO_2-eq/MJ of feed gas).[5] There is a wide variation in emissions levels and data quality between countries, with the best performers estimated to have an emissions intensity that is almost two orders of magnitude lower than the worst performers.

[5] The upstream methane emissions intensity is calculated here as methane emissions from natural gas operations divided by feed gas, assuming methane has an energy density of 55 MJ/kg. IEA methane emissions estimates are based on measured, satellite and inferred data (see Global Methane Tracker 2026 documentation for further information).

Figure 8 Upstream methane emissions from feed gas basin and upstream emissions intensities by exporting region, 2025



Notes: Mt = million tonnes. Upstream methane emissions intensity is calculated as methane emissions from natural gas operations divided by feed gas, assuming methane has an energy density of 55 MJ/kg. C & S America = Central and South America. Other North America = Appalachian, Barnett, US federal offshore, Williston; Other Asia Pacific = Browse, Clarence-Moreton, Gascoyne, Papua New Guinea Fold belt; Other Southeast Asia = Baram, Balingian, Banggai, Kutai, North Sumatra, Outboard Belt; Other Africa = Berkine, Nile Delta, Reggane, Timimoun; Other C & S America = Trinidad basin.

Source: IEA estimates based on measured, satellite and inferred data (see the Technical annex and Global Methane Tracker 2026 for further information), the Global Energy and Climate Model, and Rystad Energy (2025). For methane emissions in countries with no data availability, emission intensities are estimated using data from the United States, scaled to account for country- and production-specific factors (see the Technical annex and Global Methane Tracker 2026 Documentation for further information).

Flaring

Around 170 bcm of natural gas was flared globally, mostly associated gas from oilfields. In general, natural gas fields and fields that produce large volumes of associated natural gas flare only during emergencies, since flaring wastes a marketable product. There are three main causes of flaring at LNG facilities: plant startups and shutdowns (e.g. during commissioning, testing, process stabilisation and maintenance); unplanned events, such as equipment failure or process disturbances (e.g. compressor failure); and insufficient boil-off gas recovery.[6] Analysis by Capterio based on data for all LNG plants globally shows that flaring intensities can vary by more than a factor of 100 between the best and worst performers, with some liquefaction plants flaring up to 4% of their output.

We estimate that upstream assets feeding liquefaction plants generated about 3.6 Mt CO_2 in 2025, which translates into around 0.3 g CO_2/MJ of feed gas.

[6] During loading of LNG vessels, supercooled LNG often meets the “warm” tanks of LNG vessels, evaporating as methane. While many facilities have recovery systems to collect and re-liquefy this “boil-off” gas, their capacity is sometimes insufficient, with some of the gas volume being flared.

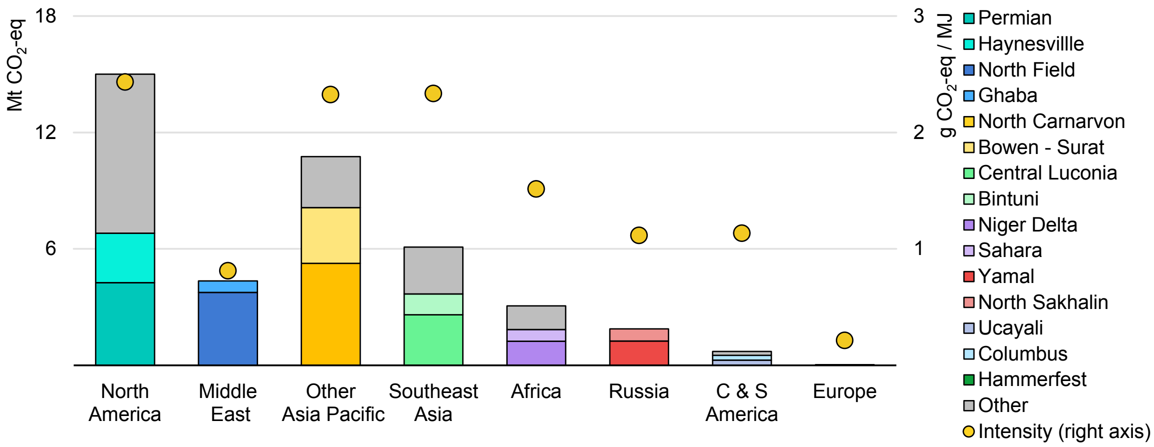
Flaring also causes methane emissions due to the incomplete combustion of natural gas at flares. We estimate that around 0.1 Mt methane was emitted from upstream facilities in 2025 (this amount is already included in Figure 8). Methane emissions from the incomplete combustion of natural gas flared at LNG facilities therefore add a further 0.2 g CO_2-eq/MJ of feed gas.

Transmission

Transmission and distribution networks connect gas processing plants to LNG liquefaction and export facilities. CO_2 emissions depend primarily on pipeline length and the distance over which gas is transported; compressor efficiency and the type of compressor driver also influence emissions levels. Globally, the average emissions intensity of energy used in transmission is 1.2 g CO_2/MJ of feed gas (Figure 9), although this varies from 0.2 g CO_2/MJ in Qatar to around 2 g CO_2/MJ in North Africa and North America.

Transmission networks were responsible for nearly 0.5 Mt of methane emissions in 2025, which translates into an intensity of 0.6 g CO_2-eq/MJ. These emissions came mostly from compressor leakages (including reciprocating and centrifugal compressors), pipeline and transmission station venting (e.g. during maintenance), and methane slip from gas-fired generators. Infrastructure age is also a key determinant of methane emissions.

Figure 9 GHG emissions from feed gas transmission by basin and average transmission emissions intensities by exporting region, 2025



Notes: One tonne of methane is assumed to be equivalent to 30 tonnes of CO_2. C & S America = Central and South America. Other North America = Appalachian, Barnett, US federal offshore, Williston; Other Asia Pacific = Browse, Clarence-Moreton, Gascoyne, Papua New Guinea Fold belt; Other Southeast Asia = Baram, Balingian, Banggai, Kutai, North Sumatra, Outboard Belt; Other Africa = Berkine, Nile Delta, Reggane, Timimoun; Other C & S America = Trinidad basin.
Source: IEA analysis based on data from Zhu et al. (2025), EERA (2024), and FENEX (2024).

The values reflect two broad transmission configurations typically observed in LNG supply chains. In integrated LNG projects, gas is transported via dedicated pipelines directly from the field or treatment facility to the liquefaction plant. These systems are common in countries such as Qatar and Australia. The pipelines are generally short and involve fewer compressor stations, which results in lower transmission-related emissions. Open transmission networks transport gas through large, shared pipeline systems before it reaches the LNG facility, a configuration most commonly found in the United States. Gas may travel longer distances and pass through multiple compressor stations, with emissions distributed across the broader network rather than linked to a single LNG project. Longer transport distances generally increase emissions, both through higher compression requirements and greater potential for methane leakage along the network.

Liquefaction

Liquefying natural gas is the most energy-intensive process in the LNG supply chain and, on average, emits around 6.1 g CO_2-eq/MJ of LNG delivered. Most large-scale onshore LNG export terminals typically consume around 10% of the energy content of the feed gas to power their operations. Most of this energy is used for cooling the natural gas to -162 °C. Energy consumption varies significantly depending on the liquefaction process, natural gas feed composition and the type of main refrigerant compressor driver (e.g. electric motor or gas turbine). For fully electrified facilities, such as Freeport LNG, energy consumption is significantly lower.

The different steps involved in the treatment and liquefaction of natural gas release CO_2 and can result in methane vents and leaks into the atmosphere. We estimate that CO_2 emissions account for around 95% of total GHG emissions from liquefaction plants. A large fraction of CO_2 emissions comes from mechanical drive turbines that drive compressors used in the refrigeration cycles and power generation turbines in other liquefaction processes. Smaller contributors include flaring and naturally occurring CO_2 emissions, as well as natural gas combustion for pretreatment and liquids handling processes like dehydration, gas sweetening, mercury removal, condensate stabilisation and fractionation.

Methane emissions can occur during gas treatment, liquefaction and storage. Sources include incomplete combustion during flaring, releases from compressor seal vents during routine operations, and equipment degradation over time. Additional emissions may arise during maintenance activities, as well as from acid gas recovery units and nitrogen rejection units. Small quantities can also be emitted as boil-off gas (i.e. LNG that regasifies as it warms over time), particularly when it is not fully recovered and used.

Emissions vary depending on the technologies, facility type (e.g. onshore or floating facilities) and operational practices used. For example, mixed refrigerant-based processes such as single mixed refrigerant (SMR), dual mixed refrigerant (DMR) or propane precooled mixed refrigerant (C3MR) have different energy intensities than cascade processes. Emissions intensities vary further due to the turbine designs and models used in the liquefaction process, with older technologies often being less efficient than the latest ones.

Floating LNG plants may face efficiency penalties compared to onshore facilities due to inherent space, weight and operational constraints. These constraints limit process optimisation, equipment sizing and redundancy, often requiring more compact and conservative machinery designs that operate outside optimal efficiency windows.

Shipping

There are more than 800 LNG-carrying ships in operation, with around 200 under construction for delivery by 2028. Each year, these ships make around 7 000 round-trip voyages to deliver LNG from liquefaction to regasification terminals. The main types of LNG carriers handle around 90% of annual LNG trade (Table 1).

Table 1 Summary of selected LNG carrier types and key characteristics, 2025

Carrier type	Stroke type	CO_2 emissions intensity (g CO_2/MJ of LNG per 1000 km)	Average methane slip range (%)	Share of market (%)
Dual-fuel diesel electric (DFDE)	Four	0.12	3-6	24
Gas injection (ME-GI)	Two	0.12	0.1-1.6	11
Gas admission (ME-GA)	Two	0.12	1-2	10
Steam turbine	Not applicable	0.24	0	21
Dual-fuel engine (X-DF)	Two	0.11	0.6-3.8	25

Notes: Share of the market refers to LNG carrying capacity of ships currently in service. Methane slip is expressed as a percentage of gas used in the main engines (excluding auxiliary generators). CO_2 emissions intensity is expressed per MJ of LNG delivered at the regasification terminal. MAN's ME-GA engines have been discontinued.

Source: IEA analysis based on data from Thinkstep (2019), FUMES (2024), Balcombe et al. (2022), ICIS LNG Edge (2026).

On average, around 2.7 g CO_2-eq are emitted per MJ of LNG delivered by an average-sized carrier. This varies significantly depending on voyage distance, fuel use, engine type and performance, engine load and other operational conditions. The two main sources of emissions during shipping are fuel combustion and methane slip. Methane slip occurs when unburnt methane escapes through engine exhaust into the atmosphere.

Methane slip is more prevalent in low-pressure four-stroke engines such as DFDE ships that use boil-off gas, especially when these ships operate at lower engine loads. Steam ships, which use high-pressure steam as the propulsion source, have negligible methane slip, but they have relatively high fuel consumption. In recent years, operators have moved towards more advanced designs – such as ME-GI and X-DF ships – with greater efficiencies and lower methane slip. Innovations that have had positive effects on emissions intensity include the use of two-stroke instead of four-stroke engines, alongside the transition from spherical Moss tanks to membrane-type containment systems.

In total, around 900 petajoules (PJ) of fuel – primarily boil-off gas, but also heavy fuel oil and marine gasoil – were used to power ships transporting LNG in 2025. This led to emissions of around 45 Mt CO_2 and a further 12 Mt CO_2-eq of methane emissions, equivalent to a combined GHG emissions intensity of around 2.7 g CO_2-eq/MJ of LNG delivered. This represents about 5% of total international CO_2 shipping emissions of around 1 000 Mt CO_2 in 2025.

Emissions from the highest-emitting 10% of journeys were more than ten times greater than those from the lowest-emitting 10%. Differences in fuel type, ship speed and engine type play a role in this variation, but the primary factor explaining the wide range is the distance travelled. On average, a round-trip voyage for an LNG carrier was 14 000 km in 2025, but distances ranged from less than 500 km to over 50 000 km. On a regional basis, the emissions intensity of LNG-carrying ships varies significantly. For example, LNG shipped to the European Union has an average shipping emissions intensity of around 2.2 g CO_2-eq/MJ, whereas LNG shipped to the People’s Republic of China (hereafter, “China”) has an average intensity of around 3.5 g CO_2-eq/MJ. The routes with the highest emissions intensity were between Africa and Asia in 2025.

These estimates are broadly consistent with the range reported in recent literature. Thinkstep (2019) estimated LNG maritime transport emissions at approximately 2.5 g CO_2-eq/MJ of delivered LNG, while recent measurement- and simulation-based studies by Balcombe et al. (2022) and Rosselot et al. (2024) suggest a wider range of roughly 2 to 8 g CO_2-eq/MJ, reflecting substantial variability in vessel design, operating conditions and methane slip. The CO_2 estimates here are also broadly consistent with LNG ship GHG emissions reported through the EU Monitoring Reporting and Verification and FuelEU Maritime regulations, although the reported methane slip values show considerable variability. Primary measurement campaigns have also indicated that methane emissions from LNG carriers can exceed earlier default assumptions, particularly from engine slip, highlighting the continuing uncertainty associated with these emissions.

Regasification

LNG cargoes are offloaded and regasified at onshore or offshore facilities, or at specially designed floating storage and regasification units. Depending on the geography, scale and type of application (e.g. for peak-load shaving or for baseload generation), operators choose from available technologies, with varying degrees of efficiency, operational complexity, capital expenditure requirements and emission characteristics. The main technologies used to regasify LNG are open-rack vaporisers (ORVs), which are used in nearly 90% of the world's regasification plants, submerged combustion vaporisers (SCVs), shell and tube vaporisers, intermediate fluid vaporisers and ambient air vaporisers.

The main sources of emissions at ORV regasification plants stem from the power consumption of pumps circulating the heating fluids and LNG, boil-off gas compressors, other utilities, and the flare pilot. For SCVs, the primary source of emissions is the combustion of natural gas to heat the LNG. Regasification energy demand typically consumes 0.3% to 0.5% of the LNG that is imported. Other emissions come from the electricity used in the regasification plant, methane emissions from plant hardware (e.g. leaks from compressors, valves, flanges and fittings, and maintenance activities), and emissions related to LNG loading, unloading and bunkering activities, where applicable.

Total GHG emissions intensity from regasification is around 0.3 g CO_2-eq/MJ of regasified LNG. Significant regional variations have not generally been observed. Estimates typically range from 0.2 to 0.4 g CO_2-eq/MJ using gate-to-gate and life-cycle assessment approaches that account for energy requirements, losses and full supply chain emissions. An exception is China, where reported emissions intensities are higher, at 0.5 to 0.6 g CO_2-eq/MJ.

Box 4 Comparing the full life-cycle emissions intensities of LNG and coal

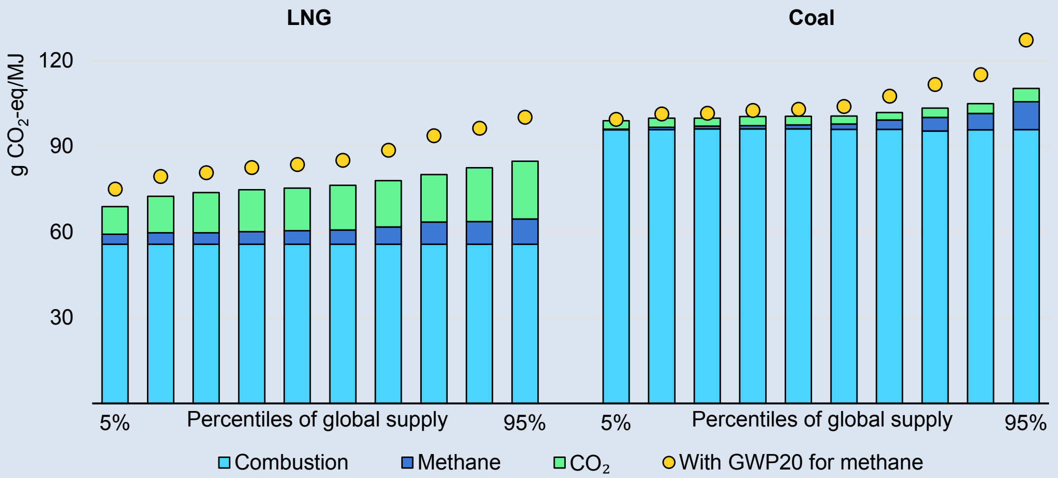
A common claim is that methane emissions along the gas supply chain result in LNG having a higher life-cycle GHG emissions intensity than coal. IEA analysis does not support this conclusion. While there is a wide variation in the emissions intensities of coal and LNG, when all direct and indirect GHG emissions are considered (from production to end-use combustion, for power and heat generation), we estimate that LNG results in about 25% fewer emissions than coal across energy use cases of these fuels (Figure 10).

Globally, on average, the life-cycle GHG emissions intensity of electricity produced from LNG is around 40% lower than electricity produced from coal. This is because gas-fired power plants are generally more efficient than coal-fired plants at generating electricity (the global average efficiency of gas-fired plants is 47%, while for coal-fired plants, it is 37%).

Around 99% of the LNG consumed in 2025 had fewer life-cycle emissions than coal. The choice of global warming potential (GWP) used to convert methane to CO_2-eq has some impact on this share, but it does not change the overall picture. When using a 20-year GWP rather than a 100-year GWP, we estimate that more than 90% of the LNG consumed in 2025 still has lower life-cycle emissions than coal.

Nonetheless, comparing LNG only with coal sets the bar too low. Minimising the GHG emissions intensity of LNG remains essential; it is not enough simply to outperform the most carbon-intensive fuel.

Figure 10 Estimated life-cycle GHG emissions intensities of LNG and coal, 2025



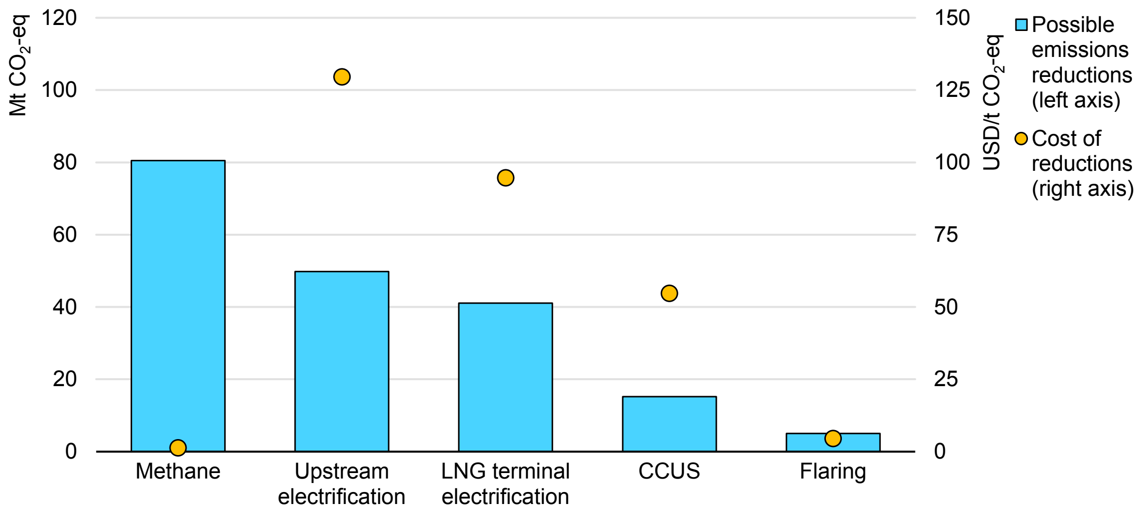
Notes: GWP20 = 20-year global warming potential; g CO_2-eq/MJ = grammes of carbon dioxide equivalent per megajoule.
Source: IEA estimates (see Technical annex and Global Methane Tracker 2026 Documentation).

Chapter 2: Emissions reduction opportunities and costs

Summary

Large emissions reductions across the LNG supply chain are technically achievable today. Many measures can be implemented at low or moderate cost. Reducing methane emissions is the single most important and cost-effective opportunity to lower overall emissions from LNG supply. Other options include electrification using low-emissions electricity, energy efficiency improvements, carbon capture, utilisation and storage (CCUS), and the elimination of routine flaring (Figure 11). This section focuses on the opportunities and costs of the direct emissions reduction measures in each area. We estimate that implementing all identified measures could avoid around 200 Mt CO_2-eq of GHG emissions per year, equivalent to about 50% of total emissions from the LNG supply chain.

Figure 11 Annual LNG emissions reduction potential and global average cost of abatement by selected measure, 2025



Notes: Cost of emissions reductions can vary widely between basins, LNG facilities and countries; CO_2 abatement costs shown are global averages weighted by production. Electrification assumes either a grid connection supplied by low-emissions electricity or a dedicated renewable electricity installation. CCUS estimates are based on capturing pure streams of naturally occurring CO_2 (rather than post-combustion emissions) and injecting them into a nearby basin. One tonne of methane is assumed to be equivalent to 30 t CO_2 based on a 100-year global warming potential (IPCC, 2021).

Source: IEA estimates based on scientific literature and the latest available data, including measured, satellite and inferred data. Data availability and quality vary widely across basins, countries and regions. For methane emissions in countries with no data availability, emission intensities are estimated using data from the United States, scaled to account for country- and production-specific factors (see the Technical annex and Global Methane Tracker 2026 Documentation for further information).

Abating methane emissions using processes such as leak, detection and repair (LDAR) programmes, installing vapour recovery units or using associated gas can cut emissions by about 80 Mt CO_2-eq annually across upstream and downstream natural gas operations. Reducing flaring at LNG facilities and fields supplying feed gas could lower annual emissions by a further 5 Mt CO_2-eq. Upfront investment is needed to deploy methane abatement measures, but many of these provide sufficient gas savings over their lifetimes to cover the required outlays. As a result, around half of methane emissions from LNG supply could be abated at no net cost. However, the deployment of cost-effective measures is often constrained by practical and commercial barriers, including limited awareness of emissions sources, competing investment priorities, split incentives and contractual arrangements, upfront capital requirements, workforce constraints, and uncertainty over how to bring recovered gas to productive use.

The electrification of upstream facilities and LNG terminals, and the use of low-emissions electricity to power these, would significantly reduce the emissions associated with liquefying and compressing natural gas. Several electrified LNG facilities have already been established, although electrifying some existing LNG facilities may be challenging, particularly those that are nearing the end of their technical lifetime. In total, we estimate that electrification of a selection of LNG liquefaction terminals, based on an assessment of the feasibility of connecting to grids or generating low-emissions electricity, could cut annual GHG emissions by around 40 Mt CO_2-eq. In addition, more than 40% of upstream natural gas production sites that feed LNG terminals are near an electricity grid, and, depending on economic and technical factors such as grid access and reinforcement needs, electrifying these facilities is also an option to reduce emissions. Doing so could cut another 50 Mt CO_2-eq. The savings calculated here account for cases where the average grid emissions intensity is significantly below that of the natural gas-based power generation technology currently used at LNG facilities and in upstream operations.

The use of CCUS is under way across parts of the LNG supply chain, as naturally occurring CO_2 is already separated during processing, especially at integrated LNG project sites. In addition, regulatory frameworks in some producer countries are beginning to incentivise CCUS deployment. Our analysis indicates that an additional 15 Mt CO_2 could be captured annually from liquefaction plants in the form of naturally occurring CO_2, in addition to the 15 Mt CO_2 per annum of projects that are already existing or under development, at an average cost of around USD 50/t CO_2-eq, assuming the availability of a nearby storage formation. Sharing lessons learned and experiences from the establishment and operation of routine and at-capacity gas capture and injection systems will be key to maximise the benefits of this technology.

We estimate that the upfront capital investment required to electrify upstream operations supplying a selection of LNG terminals would be around USD 70 billion, while electrifying operations at a selection of existing LNG terminals would cost around USD 55 billion. Around USD 8 billion of additional investment would be required to deploy CCUS to capture naturally occurring CO_2 from natural gas produced from fields with high CO_2 concentrations, for projects which do not already have plans to do so, while deploying all methane abatement and flaring reduction measures would cost just over USD 5 billion.

Implementing all available measures could avoid a total of 200 Mt CO_2-eq/year and would have a weighted-average abatement cost of USD 60/t CO_2. Globally, this would add around USD 0.2-1.50/MBtu to the delivered cost of LNG from existing facilities, depending on the pathways chosen. Integrating such measures into new greenfield LNG projects during the front-end engineering and design (FEED) phase would likely be less costly than retrofitting existing facilities (Figure 12).

Figure 12 Toolkit of opportunities and costs to reduce emissions from across the LNG supply chain, 2025

Lever	Production and processing	Transmission	Liquefaction	Shipping	Regasification	Abatement potential	Cost of implementation
Methane abatement	LDAR; VRU; blowdown capture; combustion optimisation	LDAR; blowdown capture; predictive maintenance; compressor optimisation	BOG recovery; dry-seal compressors; operational optimisation	Low methane-slip engines; methane oxidation catalysts; load optimisation	BOG recovery; VRUs; improved tank pressure management	●●●	●
Flare reduction	Gas re-utilisation; flare-tip upgrades; flare efficiency monitoring	Blowdown capture	Operational optimisation and start-up planning; flare monitoring	Not applicable	Blowdown capture	●	●
Efficiency	Operational optimisation; turbine upgrades; autonomous control	Compressor optimisation; pipeline flow optimisation; internal coatings	Turbine upgrades; efficient refrigeration cycles; waste heat recovery	Slow steaming; optimised ship design and operations; hull maintenance	Efficient regasifiers; waste heat integration; cold energy utilisation	● - ●●●	● - ●●●
Electrification	Electrified field and processing equipment	Electric-drive compressors	Electric-drive compressors; replacement of onsite gas-fired generation	Emerging technology: hybrid propulsion systems	Electric vaporisers; electrified pumps and terminal utilities	●● - ●●●	●● - ●●●
CCUS	Capturing naturally occurring CO_2 from gas processing	Not applicable	Capturing naturally occurring CO_2; post-combustion capture	Emerging technology: onboard carbon capture systems	Not applicable	●● - ●●●	●● - ●●●
Share of LNG supply chain emissions	40%	11%	33%	15%	1%		

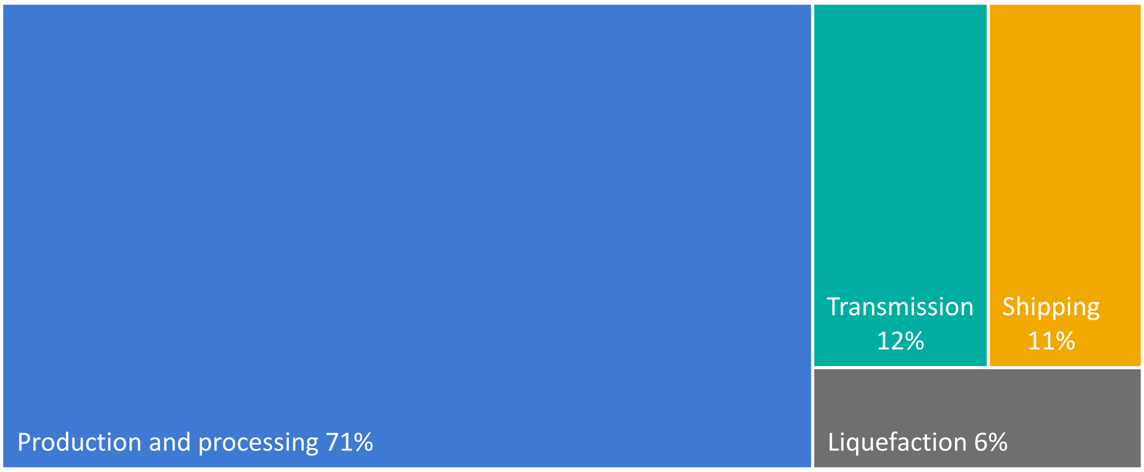
Widely applicable to existing facilities; Applicable to some existing facilities; Primarily suited to new facilities
Abatement potential ranges: ● = low (< 10 Mt CO_2-eq) ●● = moderate (10-50 Mt CO_2-eq) ●●● = high (> 50 Mt CO_2-eq)
Cost of implementation: ● = low (< USD 10/t CO_2-eq) ●● = moderate (USD 10-100/t CO_2-eq) ●●● = high (> USD 100/t CO_2-eq)

Notes: LDAR = leak detection and repair; VRU = vapour recovery units, BOG = boil off gas

Reducing methane emissions

In total, we estimate that 4 Mt of methane was emitted across the LNG supply chain in 2025 (around 10% of total methane emissions from natural gas operations globally). Upstream operations accounted for around 70% of these emissions, with natural gas transmission, LNG liquefaction, shipping and other downstream operations responsible for the remaining 30% (Figure 13).

Figure 13 Share of methane emissions across the LNG supply chain, 2025



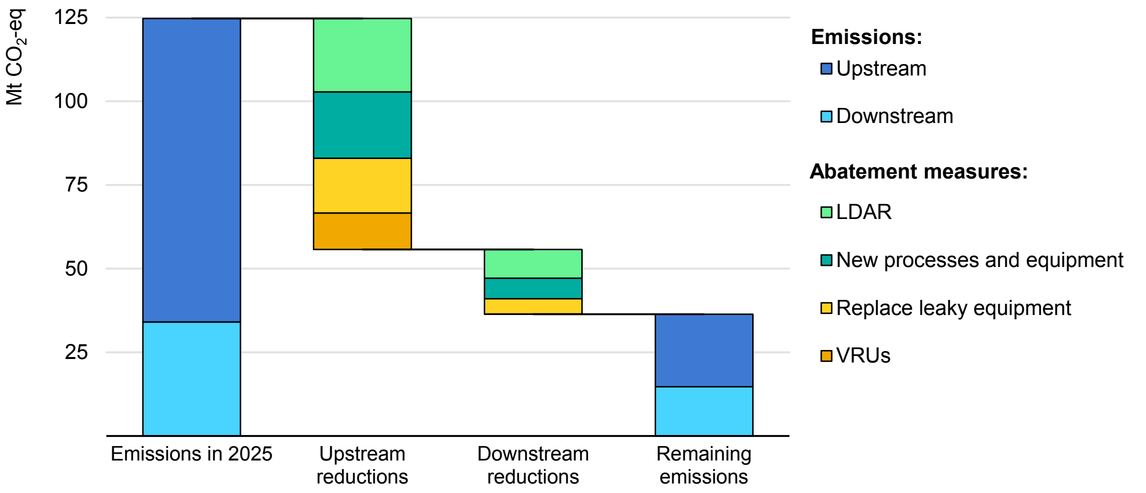
Source: IEA estimates based on measured, satellite and inferred data (see the Technical annex and Global Methane Tracker 2026 Documentation for further information).

Many technologies are now available to reduce these emissions (Figure 14). Examples include standard leak detection and repair programmes, replacing gas-driven controllers and other methane-emitting equipment with electric devices, using vapour recovery units to capture low-pressure gas that would be vented, and capturing gas during blowdowns when equipment is depressurised rather than venting it. Some measures require minimal investment and can be deployed quickly by operations staff, including improving combustion efficiency through enhanced monitoring, maximising plant reliability through predictive maintenance, and optimising operations to minimise losses (Figure 15).

In LNG facilities, boil-off gas can often be recovered using units that can be installed relatively easily, even at existing facilities. Automated air/fuel ratio controls can improve the combustion efficiency of natural gas-powered engines and turbines, and nitrogen can replace natural gas where flare systems are continuously purged. LDAR programmes can reduce unintentional emissions, while measures such as using compressors with dry seals can reduce emissions during normal operations. Several additional measures are available to address emissions from utilities, storage, pumps and other equipment present at LNG facilities. Minimising the number of start-ups, alongside other operational improvements, can also help reduce emissions.

Methane emissions from shipping can also be minimised. Measures include avoiding low engine loads and implementing cylinder deactivation during low-load operation. Other options include improving operational controls, such as process control, variable valve timing, gas metering and optimal air/fuel ratios, or using engine designs that minimise methane slip. Efforts are also under way to deploy methane oxidation catalyst systems that can further reduce methane slip.

Figure 14 Methane emissions from the LNG supply chain and emissions reduction potential by abatement measure, 2025



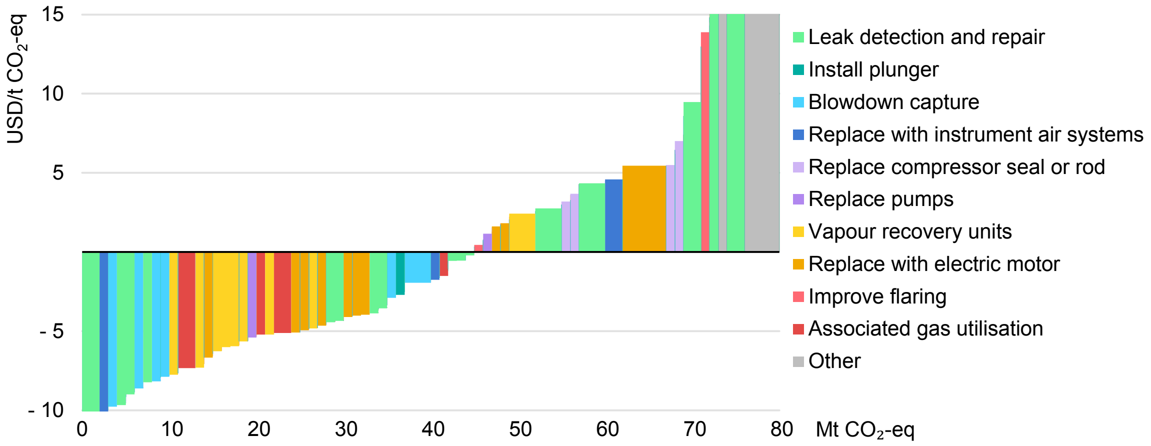
Notes: LDAR = leak detection and repair; VRU = vapour recovery units. “New processes and equipment” includes blowdown capture, routing vents to recovery systems, measures to improve combustion efficiencies, and retrofitting ships to use engines with lower methane emissions. "Replace leaky equipment" includes instrument air systems, electric pumps, and other measures that involve replacing existing equipment. One tonne of methane is assumed to be equivalent to 30 t CO_2 based on the 100-year global warming potential (IPCC, 2021).

Source: IEA estimates based on measured, satellite and inferred data (see the Technical annex and Global Methane Tracker 2026 Documentation for further information).

We estimate that deploying all methane abatement technologies currently available across the LNG supply chain would reduce methane emissions by around 70% from 2025 levels. Overall, we consider production and emissions from around 51 upstream basins supplying feed gas for LNG exports. Emissions intensity of delivered LNG would fall from around 0.7% to 0.2%, and the average downstream methane emissions intensity would fall from around 0.3% to 0.1%.[7]

[7] Downstream methane emissions intensity is calculated here as methane emissions from transmission, liquefaction, shipping and regasification divided by natural gas delivered to the regasification terminal, assuming methane has an energy density of 55 MJ/kg.

Figure 15 Marginal abatement cost curve for reducing methane emissions from the LNG supply chain by abatement measure, 2025



Notes: Other includes green completions, pipeline pump-down before maintenance, installing methane-reducing catalysts and retrofitting LNG carriers with engines that minimise methane slip. One tonne of methane is assumed to be equivalent to 30 t CO_2 based on the 100-year global warming potential (IPCC, 2021).
Source: IEA estimates based on measured, satellite and inferred data (see the Technical annex and Global Methane Tracker 2026 Documentation for further information).

More than 80% of upstream LNG flows comes from companies that are members of the Oil and Gas Methane Partnership 2.0, a measurement-based reporting framework for the oil and gas industry (see Chapter 3). Several member companies of the partnership already report upstream methane emissions intensities of much less than 0.1%.

Box 5 Industry efforts to reduce methane emissions across the LNG supply chain

Several companies across the LNG supply chain are deploying measurement-based monitoring and targeted operational upgrades to reduce methane emissions. For example, Cheniere Energy conducted detailed measurement campaigns at its liquefaction facilities and set an operational methane emissions intensity target of 0.03% per tonne of LNG produced across its two US Gulf Coast liquefaction facilities. At the transmission and regasification stage, Enagás has reduced emissions intensity by eliminating gas-driven pneumatic devices, installing boil-off gas compressors at regasification plants and deploying electric pumps.

Similar approaches are being implemented upstream and at gas-processing facilities. At Shell, methane emissions from assets under its operational control declined by 78% between 2016 and 2025, supported by enhanced leak detection and repair programmes, improved flaring efficiency and operational improvements. At the company’s Groundbirch natural gas operation in British Columbia, upgrades such as electrifying processing equipment, replacing gas-driven pneumatics and deploying continuous leak detection systems have further reduced operational emissions. More broadly, the natural gas that supplies Canada's LNG exports is produced under increasingly stringent methane regulations. With the deployment of technologies such as multi-well facilities and advanced leak detection and repair programmes, these measures support Canada's ambition to reduce methane emissions from the oil and gas sector by 75% below 2012 levels by 2030.

Likewise, Petronas has reported a reduction of around 60% in methane emissions across its natural gas value chain in 2024 relative to 2019 levels, supported by measures such as the elimination of venting through vent-to-flare projects and upgrades to acid gas removal units. These reductions align with Malaysia's methane mitigation efforts under the Global Methane Pledge and associated national initiatives.

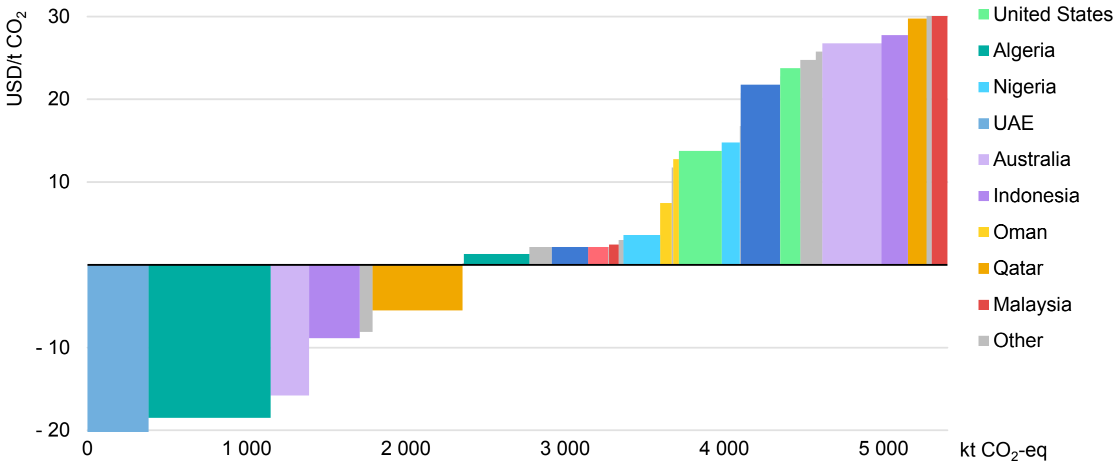
Together, these examples show how combining improved measurement with targeted operational improvements can deliver substantial methane reductions across the LNG supply chain.

Reducing flaring

There are many options to use natural gas that would otherwise be flared, including by transporting it to consumers through new or existing gas networks, reinjecting it to support reservoir pressure, or converting it to LNG (Figure 16). The gas can also be used to generate power, potentially in facilities equipped with CCUS to reduce emissions.

Methane emissions from flares should be minimal when they are properly designed, maintained and operated. However, this is not always the case, and higher emissions can occur due to factors such as weather and changes in production rates. Occasionally, an active flare may be extinguished entirely, resulting in the direct venting of methane gas to the atmosphere instead of combustion. This also poses a major health and safety risk. We estimate that flares have a global average combustion efficiency of around 90%, significantly lower than the commonly assumed value of 98%.

Figure 16 Marginal abatement cost curve for reducing flaring emissions along the LNG supply chain by exporting country, 2025



Notes: Does not include avoided methane emissions. Abatement options include new gas pipelines or pipeline connections, mini-compressed natural gas and mini-LNG technologies, gas-to-power projects, and re-injection, as outlined in previous IEA analysis. Other includes Angola, Cameroon, Congo, Egypt, Equatorial Guinea, Mauritania, Mozambique, Norway, Peru, Rest of Asia, and Trinidad and Tobago.
Source: IEA analysis including data from the World Bank global gas flaring report.

Technologies and maintenance practices can improve the efficiency of existing flares. For example, modern flare tip designs improve fuel-air mixing and achieve higher combustion efficiencies, significantly reducing emissions resulting from incomplete combustion.

Flaring reduction projects can face many barriers, including lack of infrastructure, contractual terms that prevent natural gas savings from affecting revenues, and information gaps regarding flared volumes and characteristics (for example, the share of flaring that is routine). In the LNG supply chain, most flaring reduction options would have a net positive cost in the absence of regulatory requirements. Small flared volumes can make it difficult to recover investment costs through new infrastructure development or gas transport. Reducing flaring at offshore facilities is often even more challenging because of space and weight constraints, as well as higher investment requirements.

Nevertheless, several measures require little investment and are often cost-effective. These include better planning of commissioning and maintenance activities to avoid flaring during facility start-ups, as well as operational and equipment optimisation to reduce process upsets and flaring. Measuring actual flare destruction efficiency during maintenance activities can provide more accurate data to evaluate the benefits of flaring reduction measures.

Increasing process efficiency

Production and processing

A large portion of the energy required at upstream facilities is used to power electrical equipment. This electricity is often generated using small-scale, inefficient on-site diesel or natural gas generators. Electrifying field equipment and ensuring it is well maintained are often the most effective ways to improve the efficiency of field operations (discussed in detail in the next section).

Optimising well performance can reduce energy use during production while increasing throughput by up to 25%. This can be achieved, for example, through autonomous well-control systems that respond dynamically to reservoir pressure. These systems are commercially available, but their use requires a high degree of digitalisation, including real-time sensors, data connectivity and skilled personnel. Opportunities are typically concentrated at larger fields, and we estimate that the practical applicability of these tools is limited to about 30% of LNG-linked upstream assets in operation today. For these assets, based on information received from industry and service providers, upfront investment is around USD 100-500 thousand per well pad and USD 50-200 thousand for subsequent deployments, with a payback period of a few months at a gas price of USD 3/MBtu. In less digitally mature fields, upfront investment can rise to USD 1-5 million, depending on operational complexity, while potentially delivering larger efficiency gains.

Using more efficient equipment, such as combined-cycle rather than open-cycle gas turbines at sufficiently large greenfield gas processing plants, and operating is closer to full load can reduce energy requirements by about 30%. Our analysis suggests that such upgrades typically have a payback period of five to eight years. However, deployment is often constrained by the availability of capital for the initial investment, as well as supply chain, site-specific and operational limitations.

Transmission

Transmission includes pipelines, gathering and boosting stations, and compressors stations. Efficiency improvements can be achieved by optimising compressor performance and improving gas flow through pipelines.

Compressor stations typically consume 3 to 5% of the transmitted gas as fuel. Load optimisation and AI-based control tools can reduce consumption by over 5% by improving compressor operating profiles. Based on information provided by service providers, AI solutions for gas turbines can achieve payback times of about 2 years in medium-sized gas transmission systems (1 bcm/y) at negative abatement costs.

Transporting oil and gas from the point of extraction to processing facilities can consume up to 7% of the produced energy, depending on fluid characteristics, flow regime, pipeline diameter and transport distance. Internal pipeline coatings can cut energy consumption in gas transmission by up to 50% by improving flow efficiency, as well as reducing maintenance costs. We estimate that internal coatings in greenfield gas transmission pipelines can achieve payback times of around two to three years. However, costs and benefits vary over a wide range, depending on material costs, application methods, pipeline size and operating conditions, and additional services like inspection and testing. Despite limited deployment data, this technology is considered standard practice for new pipelines in North America and Europe but is less common in regions with large legacy assets, where retrofits face economic and operational constraints.

Good flow assurance practices can also improve performance. Examples include preventing hydrate plugs that can lead to increased flaring or emergency venting, and keeping pipelines clean through regular pigging. These solutions are applicable across a range of pipeline operations and are particularly effective in long-distance transport and regions with a high risk of hydrate formation.

Liquefaction

Liquefaction is the most energy-intensive process in the LNG supply chain, with energy use dominated by turbines driving refrigeration compressors and by power generation for plant operations. Fuel consumption can be reduced through several measures, including higher-efficiency turbines, mixed refrigerant or multicycle refrigeration processes, and improved heat integration through the use of heat pumps, cold adsorption units and gas turbine air chilling systems. Full electrification of liquefaction facilities, which can deliver larger efficiency gains, is discussed in the following section.

Turbine choice for a new LNG facility is typically determined by a combination of factors, including the refrigeration process and train size, feed gas characteristics, site conditions, operational considerations (such as availability, reliability and maintenance philosophy), and project-specific factors such as experience, know-how and available equipment inventories. As a result, feasibility of efficiency upgrades varies significantly across process configurations and between greenfield developments and brownfield retrofits.

The choice of refrigeration process strongly influences driver selection. Cascade processes are multi-cycle and can be applied across a range of plant scales. In current LNG developments, C3MR and other multi-cycle concepts are widely used in mid-to-large scale trains with higher power requirements, while SMR or expansion-based processes are more commonly used in smaller-scale applications. Smaller trains may often favour aeroderivative solutions (subject to site conditions and maintenance constraints), while higher-demand configurations tend to favour heavy-duty industrial gas turbines, although aeroderivative turbines can also be applied in large-scale trains depending on project-specific conditions.

Heavy-duty simple-cycle industrial gas turbines typically operate at efficiencies of 30-48% which can be increased to above 60% with the addition of combined cycles. Aeroderivative turbines offer simple-cycle efficiencies of up to around 45% and combined-cycle efficiencies of up to around 56%, alongside faster start-up times, improved turndown and smaller footprint. These advantages are offset by lower power output per unit, greater sensitivity to high ambient temperatures, and more frequent maintenance requirements.

For new LNG facilities, installing aeroderivative turbines instead of heavy-duty industrial turbines generally requires broader changes to facility and system design, increasing capital costs beyond the turbine equipment itself. Indicative estimates suggest that the incremental investment of around USD 40-70 million per train can often be recovered within a few years through reduced fuel use, resulting in slightly negative abatement costs under favourable fuel prices and operating conditions.

At existing facilities, replacing legacy gas turbines with aeroderivative units is typically logistically complex and capital intensive. Such retrofits require civil works, new infrastructure, system integration, and can involve extended shutdowns that affect revenues and contractual obligations. Indicative abatement costs are therefore higher, typically in the range of USD 65/t CO_2 to USD 95/t CO_2, depending on train size and plant complexity. Costs could increase substantially where the required shutdown period exceeds six to eight weeks.

Improved heat integration provides an additional efficiency lever. Gas turbine exhausts generate waste heat streams at roughly 400-600 °C that can, where layout and operating conditions permit, be recovered for process duties such as regeneration and reboiler services. While some LNG plants already incorporate heat recovery, others face design or operational constraints that limit integration potential. Under favourable conditions, experimental studies suggest that additional heat integration could reduce fuel use by around 17% with payback periods of just over two years compared with conventional systems with compressor-based precooling systems. The actual benefits may vary depending on operational conditions, and the available evidence remains limited to experimental and techno-economic studies.

For greenfield projects, mixed-refrigerant cycles (such as DMR or C3MR) can reduce energy use by roughly 5-15% relative to SMR processes, albeit at higher upfront cost and technical complexity. These configurations are most effective in baseload plants with sufficient scale, flexible refrigerant requirements and opportunities for waste heat recovery. SMR processes are often selected for modularised LNG facilities because of their lower project execution risks in terms of cost, schedule and quality.

Shipping

A wide range of technical and operational levers to improve the energy efficiency of LNG-carrying ships are in advanced stages of deployment today (IEA, 2024). These range from optimised ship designs to operational measures related to cruising speed and hull maintenance (Table 2). The measure with the greatest impact is slow steaming (reducing a vessel's cruising speed), which has accounted for around two-thirds of the efficiency improvements achieved by LNG carriers since 2008.

Table 2 Selected fuel-efficiency measures for LNG-carrying ships

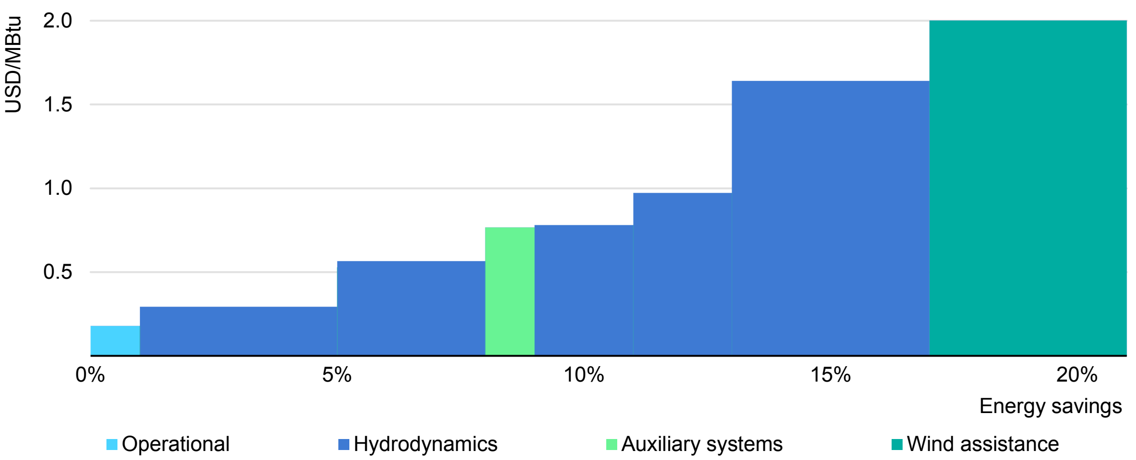
Efficiency measure	Fuel savings potential	Capital expenditure	Payback period	Remarks
Slow steaming	A 10% reduction in cruising speed can reduce fuel consumption by up to 20% (accounting for longer sailing times)	Near zero	Immediate	Largest fuel-saving measure at minimal cost; no new technology deployment required, although reducing cruising speeds lower carrying capacity (which may be partly offset through just-in-time arrivals and reduced waiting times at ports)
Operational improvements	Up to 6% per technology	USD 100-500 thousand per application for dynamic route optimisation	1-2 weeks to months	Includes trim and draft optimisation and autopilot upgrades
Hydrodynamics improvements	3-10% per technology	USD 50-600 thousand for antifouling nano-coatings, USD 1-3 million for air lubrication	Less than 4 years for coatings, 3-7 years for air lubrication	Available technologies also include improved hull designs and pre- and post-swirl devices
Auxiliary systems	Up to 2%	USD 50-100 thousand for systems with low to moderate complexity	Less than 2 years	Involves the optimisation of cooling water systems, heat exchangers, heating and ventilation systems
Wind assistance	Up to 10%	USD 0.5-3 million per ship	2-16 years depending on type	Orders are increasing, although deployment in LNG shipping has been limited to date

Source: IEA (2024), Energy Technology Perspectives 2024 (Annex C).

Several of these technologies make economic sense for shipowners and can be combined to deliver energy savings of more than 20% (Figure 17). This would lower per-ship costs by about USD 3 million per year, reduce the total cost of ship ownership by up to 10%, and achieve a payback period of less than five years, all assuming an LNG price of USD 10/MBtu.

The International Maritime Organization (IMO) has incentivised energy efficiency improvements in shipping through the Energy Efficiency Existing Ship Index, which requires ships to meet minimum emissions intensity standards by adopting higher-efficiency technologies. It has also introduced the Carbon Intensity Indicator rating, which evaluates operational emissions per cargo mile and incentivises measures such as hull cleaning and speed optimisation to improve energy efficiency. The IMO has proposed a framework to reduce shipping emissions to net zero by around 2050, although detailed implementation measures remain under negotiation. The proposal includes a goal-based marine fuel standard and a global carbon pricing mechanism. The European Union extended the EU Emissions Trading System to the maritime sector in 2024 and implemented the FuelEU Maritime regulation in 2025, increasing emissions-related costs for EU-linked LNG shipping.

Figure 17 Marginal cost of efficiency improvements for a typical LNG-carrying ship



Notes: MBtu = million British thermal units. Assumes an LNG carrier of 160 000 cubic metres of capacity built in 2025. Energy savings are calculated over the 20-year lifetime of the ship. Operational improvements include trim and draft optimisation, autopilot upgrade; Hydrodynamics include hull shape optimisation, pre- and post-swirl devices, nano-coating, air lubrication; Auxiliary systems includes optimisation of cooling water systems, heat exchangers, heating and ventilation systems.

Source: IEA analysis based on data from IMO Global maritime energy efficiency partnership, US Department of Transportation, DNV.

Regasification

The choice of regasification technology is highly dependent on geography and capacity requirements, but it also carries major implications for operational emissions and efficiency. Most LNG terminals worldwide use ORVs, which rely on seawater or ambient air to warm LNG back to its gaseous state. These systems perform well in warmer climates and have inherently low emissions because they operate without fuel combustion. Their main drawback is environmental: the discharge of cold seawater can be restricted in sensitive marine areas.

SCVs are the leading alternative. They offer reliable performance across geographies, particularly in cold regions. However, SCVs burn natural gas to heat LNG, consuming roughly 1.5% of the regasified stream and generating associated CO_2 emissions.

Brownfield projects can upgrade vaporiser technology as part of efficiency improvement programmes. One example is the Ulysse Project in France, where ageing SCVs are being refurbished and replaced by ORVs that use seawater and industrial waste heat. This transition is expected to reduce emissions by 25% per year, at a cost of approximately EUR 200 million over five years.

Beyond the choice of vaporiser, the main opportunities for improving regasification efficiency are waste heat integration and cold energy utilisation. Where terminals are located near low-grade heat sources – such as exhaust gases from floating storage and regasification units, steam from power plants, or residual heat from industrial processes – this thermal energy can be reused to reduce gas combustion in the vaporisation process. Integrating waste heat with SCVs could avoid emissions by potentially reducing fuel use by up to 25%. Cold energy utilisation involves capturing the cryogenic energy of LNG during regasification for industrial use and power generation, and some onshore terminals already deploy such systems (see Box 6).

Box 6 Cold Energy Recovery

LNG is stored and transported at approximately -162°C. Warming it up to a gaseous state at around +5°C creates a powerful cooling effect that can be captured and reused. There are several technologies available that can make use of this cooling, which can help reduce energy use and emissions while providing an additional source of revenue for LNG operators. Although the global potential is considerable, less than 1% is currently utilised. Examples of operating projects include:

- The Senboku and Himeji regasification terminals in Japan, where Daigas has operated cryogenic cold energy recovery systems for several decades. In addition to cryogenic power generation at the terminals, Daigas supplies cooling to nearby factories and chemical plants, which return warmed fluid to the terminal, reducing Daigas' power demand for regasification.

- The Barcelona and Huelva regasification terminals in Spain, where Enagás operates cryogenic cold recovery units that deliver cooling services to customers up to around six kilometres from each terminal. In Barcelona, a 15 MW installation comprising five modular heat-exchanger loops supplies cooling to a nearby district cooling network. In Huelva, an initial 4 MW loop under construction will serve the refrigeration needs of food-processing industries within the port area.

The commercial viability of cold energy recovery depends on several structural factors. These include the terminal type, as cold energy recovery is generally better suited to onshore terminals because floating storage and regasification units face greater space constraints; the utilisation rate, as projects perform best at baseload terminals operating at consistently high throughput; and proximity to cooling demand, which provide an additional revenue stream and improve project economics.

Electrification

Electrification offers a major opportunity to reduce the emissions from energy used in upstream and liquefaction facilities. In most cases, it would also improve energy efficiency. If low-emissions electricity is used, it would significantly reduce emissions.

Production and processing

Around 40% of natural gas production sites that are mostly dedicated to feeding LNG terminals lie within 10 km of an electricity grid, and 75% are in areas with good wind or solar resources. Energy needs at upstream facilities could therefore be met through grid electricity or through decentralised renewable energy systems. Norway's Equinor has led efforts to electrify upstream oil and gas operations, with grid connections or dedicated offshore wind installations being integral parts of its plan to reduce emissions by 70% from Norway's Continental Shelf production by 2040 (although the company recently cancelled some plans for electrifying upstream assets). BP has electrified a substantial portion of its assets in the Permian Basin in Texas. Shell is electrifying part of its gas processing assets feeding LNG Canada. Batteries have been deployed in Australia to reduce the need for back-up gas capacity. However, there are few examples of large-scale actions being taken by other oil and gas producers, especially for existing assets.

Policy or regulatory incentives may be necessary to stimulate the required upfront investment. These could take the form of a CO_2 price, which provided the spur for development in Norway, or of tax breaks and exemptions on a portion of electricity tariffs. Costs could be reduced if operators collaborate to build shared clean electricity infrastructure that would feed wider areas of production (e.g. recent efforts by companies operating in the North Sea). Project economics could also be improved by crediting avoided CO_2 or selling surplus renewable electricity back to the grid.

We estimate that around USD 70 billion of upfront investment would be required to electrify existing upstream assets that provide feed gas through dedicated grid connection or decentralised renewable system. This assessment excludes assets that are impractical to fully electrify, such as those requiring substantial amounts of heat and those located far from electricity grids or in areas with limited solar or wind resources. Doing so would avoid around 50 Mt CO_2 per year at a weighted average abatement cost of around USD 130/t CO_2 (adding around USD 0.8/MBtu to the delivered cost of LNG).

There are also electrification opportunities further downstream from the upstream assets feeding the LNG value chain, for example, by replacing gas turbine-driven compressors on large transmission pipelines with electric motors. Several projects have already been implemented. For instance, parts of the United Kingdom National Transmission System already use electrically driven compressors, while pipeline operators in North America and Europe, including TC Energy and Enbridge, have announced or implemented electric-drive compressor projects where suitable grid connections are available. Costs are highly site-specific and depend particularly on compressor capacity and the extent of electrical and grid-connection infrastructure required. As an indication of scale, Northern Border Pipeline's Chicago III project, which included installation of a new 12 MW electric-drive compressor and modifications at two existing compressor stations, cost USD 21 million. New-build electric-drive compressor stations are generally cost competitive with gas-turbine alternatives where high-voltage electricity is readily available.

Liquefaction

The main options for electrifying LNG liquefaction terminals are to replace or complement on-site gas turbines for power generation with renewable energy and battery storage systems, or with a grid connection where low-emissions electricity is available, and to replace mechanical gas turbines used for compression with electric motors. Emissions reductions arising from electrifying operations can vary depending on the solution chosen.

LNG facilities require electricity for a range of different processes, primarily compression (if not using mechanical gas turbines), as well as vapour and boil-off handling systems, control systems, heating, ventilation and air conditioning, and loading and berthing systems. Replacing on-site gas turbine power generation with renewables and battery storage systems, or with low-emissions grid electricity, could significantly reduce these emissions while also improving energy efficiency.

Hammerfest in Norway and Freeport LNG in the United States have, so far, been the major all-electric LNG plants. Hammerfest LNG has electrified its compressors but continues to use natural gas to power them. It is planning to develop a grid connection to draw power from Norway's hydro-dominated electricity mix. Freeport LNG, which was commissioned in 2019, secured a grid connection to supply 675 MW of power capacity to drive its compressors. This enabled a 90% reduction in site combustion CO_2 emissions and a net LNG production increase of 6.5% relative to a design based on traditional gas turbines.

Interest in all-electric LNG terminals has been growing. Woodfibre LNG, currently under construction, will be the first electrified facility in Canada. In 2024, three sanctioned LNG export projects announced plans to be fully electrified: Ruwais LNG in the United Arab Emirates, which plans to run on renewable and nuclear grid power, Cedar LNG in Canada, which plans to use grid electricity, and Marsa LNG in Oman, which is constructing a dedicated 300 MW solar photovoltaic (PV) plant.

Electrifying existing LNG terminals can involve significant costs and requires site-specific assessments of technical feasibility, as it may involve trade-offs. Initial capital expenditure can be high, and operators may be hesitant given the potential revenue loss and operational downtime associated with the conversion process. Electric transmission upgrades are also often required as LNG export facilities typically require a high electrical load.

LNG operators face several choices when implementing an electrification programme, including selecting the technology and design for compression, and the appropriate strategy for procuring power supply. For projects pursuing a grid connection, costs vary depending on factors such as distance to the power grid, level of reinforcement required and contractual conditions, including the power purchase price and grid stability. For projects building dedicated power generation capacity, it is important to ensure a continuous, reliable source of energy to maintain operations and ensure safety. Options include complementing gas turbines with variable renewable sources such as solar PV or wind and potentially adding battery capacity in a hybrid system configuration. Avoided gas use, emissions reductions and associated regulatory compliance benefits can then be factored into the economic assessment.

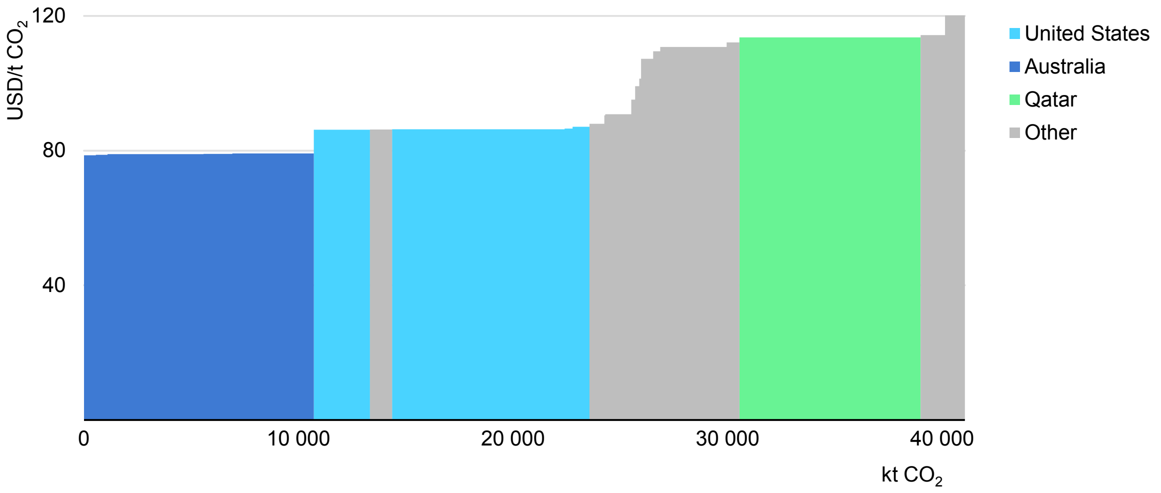
We estimate that around 70% of LNG liquefaction terminals worldwide could potentially be electrified using low-emissions electricity. A geospatial assessment of proximity to electricity infrastructure and solar and wind potential indicates that these facilities are either located within 10 kilometres of an electricity grid or in areas with favourable renewable energy resources. However, offshore terminals and facilities more than 15 years old are excluded from the assessment because of the higher costs and technical challenges associated with large-scale retrofits. This leaves around 400 bcm/year of LNG liquefaction capacity that could potentially be electrified. To calculate the marginal abatement cost of doing so, we consider the following:

On-site retrofit costs: We assume electricity demand of around 200-400 kWh/t LNG output, and that a conversion would require new electric motors and power supply infrastructure (e.g. substations), process conversion (e.g. replacing compressors, re-engineering shaft lines, optimising refrigerant cycles), and additional civil works. The capital costs of the required plant modifications vary according to the LNG technology and the current plant configurations; for brownfield conversions, incremental retrofit costs are assumed to be in the range of USD 20-60 per tonne per annum of LNG plant capacity.

Grid connection or solar plus battery: A least-cost approach is used to determine whether a grid connection or on-site power generation is the preferred option, with the key input assumptions for grid connection being power prices (averaging USD 75/MWh), distance to existing grid (with an average investment cost of USD 1.4 million per km), and level of grid reinforcement required (calculated through a spatially-resolved grid density function, averaging around USD 80/kW). For on-site power generation, it is assumed that solar capacity is oversized by a factor of 3-4 relative to plant load to account for capacity factors, and battery storage is assumed to provide 8 hours of firming to maintain continuous plant operation; around 20% of gas capacity is retained for back-up purposes. There is likewise a very wide range in capital costs; off-grid solutions are much more capital intensive whereas grid connections have high ongoing operating costs.

In total, the upfront capital cost of fully electrifying these plants is estimated at around USD 55 billion. Doing so would avoid around 40 Mt CO_2 per year associated with the energy required for LNG liquefaction (Figure 18). Considering the discounted cash flows associated with the upfront investments, allowing for downtime, additional operating costs, and avoided feed gas costs, this investment has a weighted average CO_2 abatement cost of around USD 100/t CO_2 (with most projects falling in the range of USD 80-120/t CO_2). When calculating CO_2 abatement costs, the emissions intensity of grid-based electricity is taken into account, as are the avoided emissions from lower use of feed gas to power the liquefaction process. On average, electrifying an existing plant would add around USD 0.6/MBtu to the delivered cost of LNG. These estimates reflect average conditions; actual costs can be higher for facilities requiring extended shutdowns and contractual compensation, or where significant grid reinforcement is needed. Floating LNG facilities are also generally impractical to electrify through retrofit given space and weight constraints.

Figure 18 Marginal abatement cost of electrifying selected existing LNG export terminals using low-emissions electricity, 2025



Note: Other includes Algeria, Cameroon, Canada, Mauritania, Mexico, Nigeria, Norway, Oman, Papua New Guinea, Peru, the Russian Federation and the United Arab Emirates.

Carbon capture, utilisation and storage

There are two main opportunities to deploy CCUS along the LNG supply chain: capturing naturally occurring CO_2 present in feed gas and capturing CO_2 emissions from natural gas combustion at LNG liquefaction terminals.

Three LNG projects are currently equipped with CCUS to capture naturally occurring CO_2. The Ras Laffan LNG plant in Qatar has been operating since 2019 with a capture capacity of up to 2.2 Mt CO_2 per year. The Snøhvit project in Norway captures up to 0.75 Mt CO_2 per year from the Hammerfest LNG gas stream and injects it into a saline aquifer. The Gorgon LNG project in Australia was designed to capture and store up to 4 Mt CO_2 per year over its 40-year operating life, although it has operated well below full capacity since start-up.

Several new LNG projects are also planning CCUS deployment: Tangguh LNG in Indonesia reached a final investment decision in 2024 for CCUS infrastructure targeting around 2.5 Mt CO_2 per year and Malaysia LNG is planning a major CCUS facility. In addition, more than 5.5 Mt CO_2 per year could be captured from Qatar's North Field LNG Expansion Project. Multiple LNG projects in the United States have announced CCUS plans and Australian regulations require all new gas field developments to avoid venting naturally occurring CO_2 from the start of production. All of Venture Global's LNG projects in the United States are likewise planning to use carbon capture technologies.

Naturally occurring CO_2 streams at liquefaction plants typically have high purity, and capture costs are around USD 30-80/t CO_2, including compression depending on scale. For high-CO_2 feed gas, this can add USD 0.1-0.3/MBtu to delivered LNG costs. These figures apply only to naturally occurring CO_2 separated from the feed gas stream and are not the cost of capturing combustion emissions at liquefaction plants. Further details are available in the IEA CCUS Projects Database.

CO_2 emissions from combustion are much less concentrated, and no LNG projects currently use post-combustion CO_2 capture. Capture costs are around USD 110-140/t CO_2, increasing liquefaction costs by around USD 0.7-0.9/MBtu. Retrofitting post-combustion capture at existing LNG plants is technically very complex and capital intensive, and would require major plant modifications, additional compression, transport and storage infrastructure and potentially prolonged downtime with costs reaching several hundred million US dollars. Space constraints may further increase costs if capture units cannot be installed at optimal locations.

Following capture, CO_2 must be transported and stored, with costs strongly dependent on the proximity of suitable storage. Where storage is available near liquefaction plants, transport and storage costs are around USD 15-30/t CO_2. For deep offshore storage requiring transport between mainland facilities and offshore sites, costs are expected to be higher, in the range of USD 75-150/t CO_2.

Chapter 3: Policy and finance considerations

Summary

Realising the potential for emissions reductions across LNG supply chains will depend on a combination of regulatory, voluntary and financial levers (Table 3). In many jurisdictions, particularly in Australia, Europe and North America, methane regulations have emerged as the most immediate driver of emissions mitigation, with stricter requirements on MRV, LDAR, pneumatic equipment standards and venting restrictions. These measures can also help reduce flaring. Nevertheless, their effectiveness depends on the availability of enabling infrastructure. Access to carbon capture and utilisation, reinjection options, electrification or CO_2 transport and storage can support more durable and scalable emission reductions than regulation alone.

Voluntary initiatives, including common MRV frameworks, buyer-led performance standards and third-party assurance and certification schemes, can reinforce regulatory expectations by improving transparency and comparability across LNG supply chains. Where these initiatives confer a commercial advantage, they can also strengthen the business case for emissions reductions. At the same time, financing from private capital, public programmes and multilateral institutions is important, particularly for capital-intensive measures such as CCUS, electrification and first-of-a-kind low-emissions projects. Revenue commitments, strategic equity stakes and public-private financing partnerships can further de-risk investment and support project deployment.

Table 3 Overview of policy and financing instruments

Category		Instrument	Focus
Policies	Exporting countries	National mandates and quantitative limits on GHG emissions	Sets enforceable limits on methane and CO_2 through banning routine flaring and venting, and enforcing mandatory technology standards and emissions caps
		Project permitting requirements	Embeds emissions controls and compliance obligations into project approvals and contractual frameworks
		Role of national oil companies	Drives emissions outcomes through corporate operating standards and governance frameworks
		Multi-level governance systems	Aligns federal rules with state and provincial implementation and enforcement
	Importing countries	Import standards	Imposes methane transparency and MRV requirements to imported gas and creates an intensity threshold for imported gas
		International commitments to reduce imported emissions	Signatory countries make methane reduction a central pillar of their fossil fuel policy
Voluntary initiatives	Transparency and accountability mechanisms	Monitoring, reporting and verification of emissions from LNG supply chains	Creates common MRV frameworks to improve comparability across LNG supply chains, reinforced by robust life-cycle assessment frameworks for product-focused accounting
		Buyer-led transparency and information exchange	Enables buyers to request and benchmark standardised supplier emissions data
		Third-party assurance and certification for LNG	Differentiates LNG supply based on independently verified emissions performance
	Industry collaboration and commitments	Other sector-led commitments	Collective action on methane reductions and flare elimination across the industry
Finance	Private finance institutions	Corporate finance	Company-level governance, MRV and abatement planning
		Financing linked to specific uses or performance	Incentivises emissions reductions through targeted spending or key performance indicators
	Government and multilateral financial support	Grants, below-market loans, or guarantees	Addresses high upfront costs and infrastructure gaps (e.g. grid connections, CO_2 transport and storage) that hinder projects
	Carbon markets	High-quality carbon dioxide removal credits	Channels funding towards verifiable emissions reductions and removals

Note: MRV = monitoring, reporting and verification.

Policies

Exporting countries

National mandates and quantitative limits on GHG emissions

Some LNG-exporting countries have adopted binding national regulations that directly limit emissions from upstream and LNG operations. These include bans or strict limits on routine flaring and venting, quantitative emissions caps, and performance-based standards for methane and CO_2 emissions.

Norway combines CO_2 taxation, methane-related operational requirements and permitting conditions that strongly incentivise electrification and gas utilisation. Algeria and Nigeria have national regulations that restrict routine flaring and require operators to justify flaring volumes under defined technical or safety exemptions.

Where such mandates are effectively enforced and supported by gas-gathering and utilisation infrastructure, they are associated with consistently lower emissions intensities. Where enforcement capacity or infrastructure is limited, however, regulatory requirements alone have often proved insufficient to deliver sustained emissions reductions.

Project permitting requirements

A complementary policy channel operates through project-level permitting and contractual frameworks, including environmental permits, development approvals and production-sharing contracts. These instruments often specify operational standards rather than economy-wide limits. Common requirements include prohibitions on routine flaring outside commissioning or safety events; mandatory LDAR programmes and reporting obligations; limits on venting and requirements for vapour recovery; equipment standards (such as restrictions on gas-driven pneumatics); and in some cases project-level emissions intensity thresholds.

Countries such as Oman and Qatar commonly embed these conditions directly in project approvals or operating licences. In the United States, several states also regulate emissions through air quality permits. These measures can be particularly effective for new projects, although their impact ultimately depends on monitoring, enforcement and the availability of compliance options.

Box 7 Flare reductions at QatarEnergy

Since 2012, QatarEnergy has implemented a series of measures to reduce routine gas flaring, beginning with the launch of a mitigation programme at Ras Laffan Industrial City. Initial efforts focused on monitoring and repairing valves, recycling fuel gas during shutdowns and start-ups, and reducing purge gas volumes. In 2014, the company commissioned the Jetty Boil-Off Gas Recovery Project, enabling more than 90% of boil-off gas generated during LNG loading to be recovered rather than flared. The initial investment was around USD 1 billion, but studies estimate a payback period of three years (assuming an LNG price of USD 10/MBtu).

Since 2014 a further USD 200 million was invested in flare-reduction projects, including facility upgrades and enhanced operational controls. Flaring at on-plot facilities was reduced by around 70%, while flaring associated with LNG loading fell by more than 90%, with a jetty boil-off gas recovery project alone avoiding 1.6 Mt CO_2 emissions. QatarEnergy has set a target of achieving zero routine flaring by 2030, aligned with international efforts to eliminate routine gas flaring.

Role of national oil companies

In countries where national oil companies (NOCs) dominate upstream production and LNG operations, emissions outcomes are often shaped less by formal regulation than by corporate operating standards and governance frameworks.

More than 30 NOCs have joined the Oil and Gas Decarbonization Charter (OGDC) and incorporated emissions reduction targets into internal standards, investment criteria and operating procedures. This can encourage joint-venture partners and contractors to meet defined emissions performance levels even in the absence of explicit legislation. Recent IEA analysis indicates that NOCs with strong governance and clear operational mandates can achieve methane emissions reductions comparable to those delivered under formal regulatory regimes, particularly where standards are applied consistently across operated assets. Rapid and cost-effective methane abatement by NOCs could reduce methane emissions by up to around 30 Mt per year by 2030.

Multi-level governance systems

In some federal countries, such as the United States, methane and flaring outcomes are shaped by multi-level regulatory systems in which federal rules are complemented by subnational implementation and enforcement. These frameworks combine methane standards (including LDAR and equipment requirements), waste-prevention rules and reporting obligations, resulting in substantial variation across jurisdictions, even within the same basin.

Australia and Canada also operate multi-level governance systems, but LNG-related emissions outcomes are often driven by federal levers. In Australia, a large share of LNG feed gas production is offshore, where activities in Commonwealth waters are regulated under the Offshore Petroleum and Greenhouse Gas Storage Act. In addition, large LNG facilities are subject to national, federally legislated industrial emissions limits under the Safeguard Mechanism. State and territory permitting remains important in some onshore contexts, but federal policy signals typically dominate for LNG supply chains, especially for offshore developments.

In Canada, the federal government has enacted comprehensive methane regulations that apply to all upstream activities across the country. Federal regulations function as a "backstop" mechanism: provincial governments can receive exemptions from the federal regulations and enforce their own, provided these are as stringent as the federal framework.

Box 8 Policy frameworks for carbon capture utilisation and storage (CCUS) deployment

Some exporting countries have introduced policy frameworks that improve the economics of CCUS and support its deployment alongside LNG production.

In the United States, federal tax credits for captured and securely stored CO_2 (notably under Section 45Q) can materially improve CCUS project economics by creating a predictable per-tonne revenue stream, particularly for projects with access to high-purity CO_2 sources and suitable storage.

In Australia, CCUS opportunities are supported by a combination of large, well-characterised storage resources located close to major LNG-producing regions and prospective storage basins (notably in Western Australia and the Northern Territory) and established offshore regulatory frameworks for GHG storage.

These advantages can reduce development risk and support learning-by-doing, although project delivery still depends on permitting, infrastructure and commercial arrangements.

Importing countries

Many energy-importing countries recognise that fossil fuel consumption within their borders contributes to GHG emissions globally. As such, several importers are exploring policy tools to improve transparency and reduce emissions associated with imported fuels.

Import standards

Importing countries are expressing growing interest in measures that link market access to GHG emissions performance. The European Union, for example, has adopted a regulatory framework that extends methane transparency requirements to imported natural gas. From 2027, EU importers will be required to demonstrate that imported fuels are subject to MRV standards at the producer level that are equivalent to those applied within the European Union. From 2028, importers are required to report the methane intensity of imported gas, and from 2030, natural gas placed on the EU market is envisaged to be subject to a methane-intensity threshold. Secondary legislation is currently under development to define measurement and traceability methodologies required for implementation.

According to IEA analysis, if China, the European Union, Japan, Korea, and the United Kingdom were to implement a co-ordinated import standard with a methane intensity threshold of 0.2%, this could reduce global upstream oil and gas methane emissions by 20%, and potentially up to 30% if a spillover effect is assumed. Several approaches could be used to establish compliance with an import standard. Some models decouple physical LNG cargoes from their environmental attributes, allowing lower-intensity gas to be traded through certificates or other accounting mechanisms. These approaches are generally simpler and less costly for industry to implement but may weaken the incentive to reduce emissions from specific supply chains. Other models require environmental attributes to remain linked to physical gas flows. While this can strengthen incentives for emission reductions, it is typically more complex and costly to implement. Countries seeking to introduce import standards need to decide which model will be accepted as proof of compliance.

International commitments

Importing countries are increasingly signalling a willingness to tackle energy-related GHG emissions outside their borders, including through the adoption of international commitments aimed at reducing such emissions. One example of this is the Joint Statement on Drastically Reducing Methane Emissions in the Global Fossil Fuel Sector. Launched at the 30th meeting of the Conference of the Parties (COP30) to the United Nations Framework Convention on Climate Change and backed by major producing and importing governments, this initiative commits signatories to make methane reduction a central pillar of their fossil fuel policy. It supports mandatory MRV, the elimination of routine flaring and venting by 2030, and the integration of methane targets into nationally determined contributions. Signatories will also work towards establishing a near-zero methane intensity marketplace and report progress in 2026, signalling greater policy co-ordination and alignment of trade measures to drive down methane emissions across global fossil fuel supply chains.

Voluntary initiatives

Voluntary initiatives come in different forms, including MRV frameworks, buyer-led transparency and information exchanges, and certification schemes. These initiatives can deliver several benefits for operators active across LNG supply chains. A credible voluntary scheme can provide evidence that delivered LNG is associated with minimal GHG emissions, enabling high-performing operators to differentiate their supply from higher-emissions alternatives. This can help attract customers seeking fuels with lower emissions intensities, including technology companies, data centres and industrial users with voluntary climate commitments. Over time, such differentiation could also support price premiums for lower-emissions fuels, strengthening incentives for producers to curb emissions.

By enabling differentiation, voluntary schemes thus provide an avenue to reward first movers that choose to implement abatement measures where regulations do not exist yet. They can also help gas-purchasing companies and importing countries identify lower-emissions sources of supply and incorporate emissions performance into procurement decisions, supporting broader emissions reduction objectives.

While voluntary schemes have the potential to reward first movers, they are not a substitute for regulation. Industry-led efforts can play an important role, but government regulation remains critical to remove obstacles that prevent companies from getting started and ensure that emissions are reduced across the entire sector. Moreover, the current landscape is fragmented, with schemes differing in scope, methodology, definitions and grading systems. This can confuse buyers and weaken their ability to compare fuels on the basis of emissions performance. Voluntary schemes also remain constrained by partial coverage of LNG value chains, limited transparency, integrity concerns and uneven adoption across companies and countries. Among voluntary initiatives, only some certification schemes require third-party verification of emissions, which may affect the reliability of emissions reported under other approaches. Ultimately, the effectiveness of voluntary schemes depends on the use of measurement-based reporting and credible third-party assurance.

Transparency and accountability mechanisms

Monitoring, reporting and verification of emissions

Many initiatives have emerged in recent years that focus on establishing common frameworks for measuring and reporting emissions across the LNG value chain, forming the data backbone for transparency and comparability in the market.

The United Nations Environment Programme's Oil and Gas Methane Partnership (OGMP 2.0) is widely used as a reference framework for measurement-based methane reporting and has become an important point of alignment for credible MRV practices relevant to LNG supply chains. OGMP 2.0 provides guidance and tools that support a shift from generic emissions factors towards measurement-based reporting. As of August 2026, OGMP 2.0 has over 160 member companies, representing about 45% of global oil and gas production and over 80% of LNG flows. This indicates strong uptake of measurement-based reporting and significant volumes of production demonstrating higher data quality.

Members are expected to set near-term methane emissions reduction targets and report methane emissions using increasingly measurement-based approaches. Members achieve "Gold Standard Reporting" if they measure and report material methane emissions at the source and site level from operated assets within three years of joining OGMP 2.0, and from non-operated assets within five years. OGMP 2.0's reporting framework has been incorporated into the EU MER, complemented by independent third-party assurance.

Other frameworks include the Natural Gas Sustainability Initiative Protocol, a widely used, segment-specific methodology for calculating methane emissions intensity across the United States natural gas value chain. GTI Energy's Veritas framework harmonises measurement-based methane quantification across the natural gas supply chain. The International Group of Liquefied Natural Gas Importers has also developed an MRV and GHG-Neutral Framework to establish consistent criteria for calculating the GHG footprint of delivered LNG cargoes.

While MRV initiatives are growing across LNG supply chains, coverage remains uneven, with liquefaction, shipping and regasification often less systematically monitored. Most MRV initiatives focus on methane, giving less attention to other GHGs. Existing MRV schemes also differ in scope and methodology, hindering the ability of buyers to compare supply according to performance.

Buyer-led transparency and information exchange

Greater engagement from buyers has been instrumental in encouraging supplier disclosure and emissions reductions across LNG supply chains. These initiatives enable LNG buyers to request, share and compare emissions information from suppliers as part of procurement and due-diligence processes.

One example is the Coalition for LNG Emissions Abatement toward Net-zero (CLEAN), a public-private initiative in which LNG buyers from Japan and Korea send standardised questionnaires to LNG producers regarding methane management and emissions reduction efforts at the project level. Information is aggregated by the Japan Organization for Metals and Energy Security, which acts as the secretariat for CLEAN, and disseminated alongside best practices, with the aim of improving transparency and encouraging continued improvements across LNG supply chains. CLEAN is designed to complement, rather than replace, industry-led, measurement-based MRV frameworks and is currently one of the few initiatives to publish value chain emissions intensities at scale.

Third-party assurance and certification for LNG

Several initiatives support independent assessment, assurance or certification of emissions performance associated with LNG production and supply. By improving transparency and credibility, they enable differentiation between LNG supplies based on emissions performance.

One example is Methane Intelligence Quotient (MiQ), an independent not-for-profit organisation that certifies roughly 7% of global gas production. MiQ offers an asset-level technical standard to assess emissions intensities across the natural gas supply chain, including a dedicated standard covering liquefaction, shipping and regasification, supported by accredited independent auditors.

While certification schemes can allow assets with low GHG emissions to differentiate their supply, they still face numerous challenges. Measurement-based quantification is not always required, raising the risk that methane emissions could be underestimated. Questions have also been raised about the integrity and transparency of some schemes, casting doubt on the reliability of emissions reported under them. LNG liquefaction, shipping and regasification facilities are rarely certified; Grain LNG in the United Kingdom is one notable example. Most certification initiatives focus on methane, with less attention on CO_2 and electricity-related emissions (although some programmes, like MiQ, are now beginning to expand into comprehensive GHG-intensity frameworks). Certification remains concentrated in North America, with limited uptake outside this region.

Certification schemes are most useful when anchored in robust MRV frameworks, combined with strong criteria regarding transparency and independence. Harmonising certification initiatives across countries, enhancing comparability and facilitating GHG-based purchasing would further enhance their effectiveness.

Industry collaboration and commitments

Other sector-led commitments

Industry coalitions have emerged across the oil and gas sector to drive collective voluntary action on reducing methane emissions and eliminating routine flaring.

The Oil and Gas Climate Initiative (OGCI) consists of 12 oil and gas companies and aims to advance voluntary action on methane through collective commitments, leadership statements and shared technical resources. OGCI emphasises improved measurement, deployment of detection technologies and dissemination of practical guidance to support methane reduction across operations.

The Oil and Gas Decarbonization Charter (OGDC) was launched at COP28 in 2023 and has around 56 signatories. The OGDC builds on the goals and approaches established under the OGCI. Its 56 companies have stated ambitions to dramatically reduce methane and flaring emissions by 2030, towards a goal of achieving net zero operational emissions by 2050.

The Zero Routine Flaring by 2030 initiative launched by the World Bank and the United Nations in 2015 aims to end routine gas flaring by 2030. Although voluntary and not legally binding, it establishes a public commitment by endorsers. Progress is monitored through government and company reporting, as well as satellite observations. Countries and companies that have endorsed the initiative account for around 60% of global gas flaring.

ONE Future, a coalition of about 40 natural gas companies in the United States, and the Environmental Partnership initiative bring together sector participants to reduce methane emissions through the sharing of best practices and improved emissions measurement and reporting.

These commitments rely primarily on voluntary targets and co-ordination rather than standardised measurement-based reporting frameworks. On the capacity-building side, notable examples include the Association of Southeast Asian Nations' Energy Sector Methane Leadership Program and the African Energy Commission's project on Methane Emissions Management and Capacity Building in the African Oil and Gas Sector.

Finance

Many emissions reduction measures in the LNG supply chain do not require external financing, particularly for routine actions with a smaller capital footprint such as LDAR, operational improvements and small-scale equipment upgrades. Still, complementary external financing can play an important role for large capital programmes, first-of-a-kind projects, projects dependent on enabling infrastructure (e.g. gas utilisation, reinjection options, or power connections), or where access to capital remains a constraint. In these cases, financing may be available from private financial institutions, which may have their own emissions reduction goals, as well as from governments, multilateral institutions and carbon markets.

Private financial institutions

Several financial institutions have their own emissions reduction or climate targets that influence how they assess financing for oil and gas companies, in addition to their core credit assessments. This often manifests when the lender undertakes due diligence, risk assessment or portfolio construction, and involves evaluating a borrower's emissions profile and transition strategy against the lender's portfolio preferences and transition objectives. Since bank loans typically have a shorter tenor than energy transition horizons, climate-related risk management frameworks, structured engagement processes and transition targets are used to inform lending decisions, including by setting expectations on governance, transparency, and the implementation of emissions reduction measures. These can take two main forms: corporate-wide expectations or financing linked to specific use or performance.

Corporate financing expectations

Corporate-wide expectations typically focus on borrowers adopting methane governance frameworks and MRV systems, identifying and implementing specific abatement measures, and improving disclosures to enhance comparability across suppliers and routes. Meeting these expectations can result in lower transition and reputational risks for lenders, potentially resulting in improved access to capital or more favourable financing terms for borrowers. In practice, these expectations are increasingly formalised through borrower due diligence requirements related to MRV readiness, credible abatement plans and governance. They can influence pricing and access to capital even when funding is not earmarked for a single emissions reduction project.

Financing linked to specific uses or performance

Financing arrangements can also link funding conditions to the implementation of specific abatement measures or to measurable performance outcomes. Unlike traditional project finance, where repayment depends on the cash flows of a ring-fenced project, these instruments are typically structured within corporate finance frameworks but incorporate targeted incentives for emissions reductions. One approach is to link financing to the use of proceeds, whereby capital is earmarked for defined activities such as methane abatement, flaring reduction or improvements to measurement and monitoring systems. These instruments are commonly issued at the corporate level but include restrictions on how funds are allocated.

A second approach is to link financing conditions to the achievement of predefined performance indicators. These may include reductions in methane intensity, lower flaring levels or improvements in measurement quality. Such instruments introduce performance-based incentives over time, as borrowing costs can vary depending on whether targets are met.

In 2025, the Methane Finance Working Group provided guidance on the design of these instruments. For use-of-proceeds structures, it outlines eligible methane and flaring abatement activities, as well as safeguards and disclosure requirements. For performance-linked instruments, it highlights the importance of robust, comparable metrics and transparent reporting frameworks to ensure environmental integrity.

Government and multilateral financial support

Some emissions reduction measures are technically feasible but are not implemented because of practical barriers such as high upfront costs, missing enabling infrastructure (e.g. available power connections) or institutional constraints that limit implementation capacity. Government support, such as grants, below-market loans and guarantees, can lower the cost of implementation and reduce risk for investors. Blended finance can further use this public support as an enabler to mobilise larger volumes of commercial finance. Public support can also help address early-stage development risks that can otherwise prevent projects from reaching bankability.

The World Bank's Global Flaring and Methane Reduction (GFMR) Partnership is one example of this approach. GFMR provides catalytic grants, technical assistance, and policy and regulatory support, particularly in countries and for state-owned entities facing capacity constraints.

Carbon markets

Carbon credits, which are tradable units representing 1 tonne of GHG emission reductions or removals, are often used at the corporate level to help achieve emissions reduction targets while generating revenue for emissions reduction and removal projects. Carbon credits have previously been used to label some LNG cargoes as "carbon neutral", with credits purchased to compensate for the estimated life-cycle emissions associated with a cargo. This practice has drawn growing scrutiny due to the widespread use of low-cost, nature-based credits with unclear permanence and verification standards. Questions have also been raised about the calculation of emissions reductions, including risks related to the lack of regulatory additionality in jurisdictions with existing climate policies.

Nonetheless, high-quality permanent carbon dioxide removal (CDR) credits could help channel funding towards genuine emissions removal projects. For all CDR solutions, robust accounting rules, independent international verification and clear definitions are essential to ensure credibility. Initiatives such as the Integrity Council for the Voluntary Carbon Market (ICVCM) Core Carbon Principles (CCP) and the Paris Agreement Crediting Mechanism (PACM) can also help improve credit quality and market integrity. In particular, the PACM Supervisory Body adopted a new standard in late 2025 to address non-permanence and reversals in the mechanism's methodologies. The standard includes stringent requirements for long-term monitoring, liability provisions and mechanisms to address reversal risks. These developments aim to strengthen confidence that credited removals are durable over time and not subject to significant uncertainty. Around the same time, the ICVCM approved specific CDR methodologies eligible for high-integrity CCP-labelled credits, including methodologies for engineered CDR approaches.

Box 9 The use of blended finance at Gorgon LNG, Australia

The CCUS system at the Gorgon LNG project cost around USD 2 billion within a much larger LNG megaproject with total capital costs of roughly USD 55 billion. The project was primarily financed through joint-venture equity from LNG partners, including Chevron, ExxonMobil and Shell, with the core capital expenditure funded on the partners' balance sheets. Public support included a capital grant of around USD 40 million from Australia's Low Emissions Technology Demonstration Fund. Additional financing was provided by export credit agencies and commercial banks, including the Japan Bank for International Cooperation and Mitsubishi UFJ Financial Group, to support participating companies' equity stakes. These loans applied to the overall LNG project, including the carbon capture facilities.

Technical annex

Data sources and limitations

This report provides a consistent set of estimates for CO_2 and methane emissions from LNG supply chains based on the latest and best available data. These estimates reflect a detailed spatial representation linking upstream assets to LNG terminals, the latest scientific studies and measurement campaigns, and emissions data from a variety of sources including the IEA Global Methane Tracker (2026) and Global Energy and Climate Model (2025); the World Bank for flaring; the Oil Climate Index plus Gas tool (OCI+) for energy use in production and processing; the United States Energy Information Administration (EIA), Federal Energy Regulatory Commission (FERC) and Environmental Protection Agency (EPA); the International Maritime Organization (IMO); Rystad Energy; and company and country reports.

LNG supply chains are complex and can evolve quickly, and literature reviews have identified large differences in emissions estimates over time, even for the same assets. Data on GHG emissions are often not available and, even when they are available, seldom reflect direct measurements. These uncertainties are compounded by challenges in apportioning emissions to LNG supply, rather than to oil and other co-products, and in tracing feed gas from production sites to liquefaction terminals. Estimates are also often based on generic information, such as reservoir CO_2 content for naturally occurring CO_2.

We welcome all feedback, including measured, robust and transparent data sources that can help refine our estimates.

Estimating emissions

Production and processing

In this work, the mapping of upstream assets to LNG liquefaction facilities uses data from the EIA and FERC, as well as company reporting for the United States, and data from Rystad Energy for the rest of world, while recognising limitations in public disclosure and data transparency.

EIA data on LNG exports to domestic and international destinations are used to cross-check the volumes of natural gas used at each liquefaction site. We then link individual upstream gas assets known to produce LNG feed gas to each LNG terminal. Physical links and supply contracts often provide sufficient information to estimate the share of feed gas flowing to a specific terminal from each upstream asset. Where no other information is available, we estimate the contribution of each upstream asset based on its total production, pipeline capacity and other operational details (e.g. reported outages). We estimate emissions intensities for the upstream assets and calculate a production-weighted average to derive the annual average emissions intensity of feed gas at each LNG terminal. Overall, we consider production and emissions from around 51 upstream basins supplying feed gas for LNG exports.

CO_2 emissions from energy use

Our estimates of CO_2 emissions from energy use in production and processing are based on country- and production-specific data (e.g. conventional onshore, conventional offshore and shale gas) from the OCI+ tool. These estimates draw on a detailed field-by-field dataset developed by the Rocky Mountain Institute using the Oil Production Greenhouse Gas Emissions Estimator (version 3.0a), which considers the energy required for each stage of production (e.g. exploration, development, drilling, extraction, processing and maintenance).

Naturally occurring CO_2

Estimates of vented naturally occurring CO_2 emissions are based on a basin-by-basin assessment of natural gas CO_2 concentrations using data from the scientific literature, as well as company and government reports (for example, for the offshore Ichthys field in the Browse Basin, which supplies feed gas to the Ichthys LNG facility). We assume that all extracted CO_2 is emitted to the atmosphere, except for volumes already captured at facilities equipped with CCUS, which are subtracted from the total.

Methane emissions

The IEA estimates methane emissions from assets based on measured, satellite and inferred data following the methodology of the IEA's Global Methane Tracker 2026. These estimates are adjusted to account for asset-specific information, such as the type of production, the age of facilities and the type of operator (e.g. major, NOC). There is a high degree of uncertainty in estimating methane emissions, and estimates change as new measurement results emerge and as factors feeding into the estimation process change. We categorise countries according to measured data availability as "moderate", "limited" or "none".

Countries with "moderate" data availability are those whose methane emissions estimates are constrained by recent empirical datasets from airborne- and ground-based measurement campaigns that cover the majority of the country's oil and gas production and are documented in peer-reviewed studies.

Countries with "limited" data availability are those whose methane emissions estimates are informed by a) MethaneSAT observations covering at least 25% of the country's total oil and gas production; b) other peer-reviewed measurement studies covering part of a country's oil and gas activity (e.g. offshore production); or c) observations from coarse resolution satellite inversions (such as TROPOMI) available for at least 50 days of the year.

For countries with no measured data or relevant scientific study, we estimate emissions intensities by scaling production-specific emissions intensities from the United States using country- and production-specific scaling factors derived from a range of auxiliary sources.

See the Global Methane Tracker 2026 Documentation for further information.

Methane emissions also occur during transmission, liquefaction, shipping and regasification. Our estimates of emissions from transmission are based on country-specific methane emissions intensities for downstream operations, scaled to each transmission segment and modelled LNG flows, taking into account the extent of operating natural gas pipeline networks. The methane emissions intensity of liquefaction is assumed to be 0.05% (based on satellite data from GHGSat) and that of regasification is assumed to be 0.02% (based on Innocenti et al., 2023). Emissions estimates for shipping employ Independent Commodity Intelligence Services (ICIS) ship-tracking data on LNG cargoes, IMO data on ship engine types, and a range of studies to define assumptions on fuel use, emissions and operational factors, including distance travelled, energy use, propulsion technology and average vessel capacity.

One tonne of methane is assumed to be equivalent to 30 tonnes of carbon dioxide based on a 100-year global warming potential (IPCC, 2021).

Flaring

Estimates of CO_2 emissions from flaring are based on a detailed review of upstream assets, pipeline connections and data from the World Bank, which provides information on the volumes and locations of all flares in 2024, as well as country-level assumptions on the liquids content of extracted natural gas. Methane emissions from incomplete combustion at flares are based on IEA country-level estimates of combustion efficiency (see Global Methane Tracker 2026 Documentation for further details).

Transmission

Estimates of energy use and CO_2 emissions from feed gas transmission are based on life-cycle and global supply chain assessments, as well as regional reports, including Zhu et al. (2025), the European Energy Research Alliance (EERA), and Future Energy Reports (FENEX).

Shipping

Our estimates for CO_2 and methane emissions from shipping are based on a detailed bottom-up assessment of fuel use, taking into account the engine type, cargo size, voyages and fuel mix of all the ships that carried LNG in 2025. Methane slip assumptions are in line with the range reported in recent studies such as Rosselot et al. (2024), Balcombe et al. (2022) and Thinkstep (2019). Key assumptions are presented in Table 1. Our estimates align well with IMO-reported emissions (e.g. MEPC 82/6/38 reports 44 Mt CO_2 from LNG carriers in 2023, compared with our estimate of 45 Mt CO_2).

Comparisons with the interim report

The global average emissions intensity of LNG from production to regasification is estimated to have been 18.6 g CO_2-eq/MJ in 2025, slightly lower than the 19.4 g CO_2-eq/MJ estimated for 2024 in the interim report. As detailed in Box 1, LNG exports in 2025 were around 30 bcm higher than in 2024, and several new LNG producers entered the market. The main changes by supply segment are:

- **Methane:** There have been some methodological changes, as described in the Global Methane Tracker 2026 Documentation. These include revisions to the estimation of emissions intensities in countries with limited or moderate measured data, as well as updates to the underlying datasets (e.g. new data from MethaneSAT). The global average upstream methane intensity was 3.9 g CO_2-eq/MJ in the interim report, compared with 4.0 g CO_2-eq/MJ in this report. The largest decrease was observed in Nigeria, where emissions intensity fell from 10 g CO_2-eq/MJ to around 5 g CO_2-eq/MJ. These reductions were partly offset by increases in the Asia Pacific region.
- **Shipping:** The global average CO_2 emissions intensity was 2.9 g CO_2-eq/MJ in the interim report, compared with 2.1 g CO_2-eq/MJ in this report. This reflects incremental improvements in the LNG carrier fleet, as newer vessels have entered service and older steam-powered ships are used less frequently, as well as refined estimates of emissions from different LNG carrier types.
- **Transmission:** The global average emissions intensity was 2.3 g CO_2-eq/MJ in the interim report, compared with 2 g CO_2-eq/MJ in this report. This reduction is driven mainly by additional data from Zhu et al. (2025), which provide lower measurement-based emissions estimates from pipelines in the United States. A revised allocation of feed gas across producing basins also contributed to the lower transmission emissions intensity in the United States.

Abatement and electrification cost estimates

Estimates of methane abatement costs are based on the IEA Methane Abatement Model, considering emissions sources across the LNG value chain. Details of the methodology are available in the Global Methane Tracker 2026 Documentation, including information on abatement options, potential savings, wellhead gas prices and discount rates.

Estimates of flare reduction costs are based on flare size and distance from existing infrastructure. Revenue from additional gas sales is based on 2024 gas prices. For further information on abatement options and costs, see Emissions from Oil and Gas Operations in Net Zero Transitions.

Estimates of electrification costs of liquefaction and upstream facilities are based on a detailed geospatial analysis of the location and characteristics of these assets. Fields likely to cease production within the next ten years are not considered. For each facility, the assessment considers current and future upstream energy use, distance to an existing electricity grid, grid connection costs, electricity prices, emissions intensity of electricity, wind and solar resources and costs, and battery costs. The choice between grid connection or decentralised renewables, as well as the optimal mix of wind and solar capacity, is based on the option with the lowest net present value in each year.

Table 4 Regional mapping used in the report

Exporting region	Country
North America	Canada, Mexico, United States
Central and South America	Peru, Trinidad and Tobago
Europe	Norway
Russia	Russian Federation
Africa	Algeria, Angola, Cameroon, Republic of the Congo, Egypt, Equatorial Guinea, Mozambique, Nigeria, Senegal
Middle East	Oman, Qatar, United Arab Emirates
Southeast Asia	Brunei Darussalam, Indonesia, Malaysia
Other Asia Pacific	Australia, Papua New Guinea

Table 5 LNG electrification economics – key technical and economic assumptions

Generic inputs	Assumption
Electric load intensity	350 kWh/t LNG
Peak load contingency	10%
Backup gas capacity retained	20%
Grid power escalation	2.00%
Electric drive retrofit capex	USD 700/kW
Fixed grid interconnect capex	USD 20 million
Battery duration	8 hours
Battery round-trip efficiency	88%
Retrofit fixed operations and maintenance	1.50%
Solar and battery fixed operations and maintenance	2.0%
Interconnection fixed operations and maintenance	0.5%
Owner's cost/contingency	10%
Operations and maintenance escalation	2.0%
Construction period	0.5 years
Retrofit downtime	6 months
Plant-specific inputs (average values)	**Assumption**
Grid CO_2 intensity	425 $kgCO_2$/MWh
Grid power price in 2026	USD 72/MWh
Average feed gas cost	USD 1/MBtu
Lost LNG margin during downtime	USD 75/t
Grid reinforcement capex	USD 1 000/kW
Solar capex	USD 673/kWdc
Battery capex	USD 250/kWh
Distance to grid	32 km
Transmission connection cost	USD 1.2 million/km
Renewable energy source potential (1-10)	7.4

Abbreviations and acronyms

BOG	Boil Off Gas
C3MR	Propane pre-cooled mixed refrigerant
CCP	Core Carbon Principles
CCUS	Carbon capture, utilisation and storage
CDR	Carbon dioxide removal
CLEAN	Coalition for LNG Emissions Abatement toward Net Zero
COP	Conference of the Parties
CO_2-eq	Carbon dioxide equivalent
DFDE	Dual fuel diesel electric
DMR	Dual mixed refrigerant
EERA	European Energy Research Alliance
EIA	United States Energy Information Administration
EPA	United States Environmental Protection Agency
EU MER	EU Methane Emissions Reduction Regulation
FENEX	Future Energy Reports
FERC	United States Federal Energy Regulatory Commission
FSRU	Floating storage and regasification unit
GFMR	World Bank Global Flaring and Methane Reduction Partnership
GHG	Greenhouse gas
GWP	Global warming potential
ICIS	Independent Commodity Intelligence Services
ICVCM	Integrity Council for the Voluntary Carbon Market
IEA	International Energy Agency
IMO	International Maritime Organization
LDAR	Leak detection and repair
LNG	Liquefied natural gas
ME-GA	Gas admission
ME-GI	Gas injection
MiQ	Methane Intelligence Quotient
MRV	Monitoring, reporting and verification
NOC	National Oil Company
OCI+	Oil Climate Index plus Gas
OGCI	Oil and Gas Climate Initiative
OGDC	Oil and Gas Decarbonization Charter
OGMP 2.0	Oil and Gas Methane Partnership

ORV	Open-rack vaporiser
PACM	Paris Agreement Crediting Mechanism
SCV	Submerged combustion vaporiser
SMR	Single mixed refrigerant
VRU	Vapour Recovery Unit
X-DF	Dual fuel engine

Units

bcm	billion cubic metres
km	kilometre
°C	degrees Celsius
g	gramme
kg	kilogram
t	tonne
Mt	million tonnes
MJ	megajoule
PJ	petajoule
kW	kilowatt
MW	megawatt
kWh	kilowatt-hour
kWdc	kilowatt (direct current)
MWh	megawatt-hour
MBtu	million British thermal units
USD	US dollars
EUR	Euro

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