Global Methane Tracker

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Contents

Background

The IEA's estimates of methane emissions are produced within the framework of the IEA's Global Energy and Climate Model (GEC). Since 1993, the International Energy Agency (IEA) has provided medium- to long-term energy projections using this large-scale simulation model designed to replicate how energy markets function and generate detailed sector-by-sector and region-by-region projections for the *World Energy Outlook* (*WEO*) scenarios. Updated every year, the model consists of three main modules: final energy consumption (covering residential, services, agriculture, industry, transport and non-energy use); energy transformation including power generation and heat, refinery and other transformation (such as hydrogen production); and energy supply (oil, natural gas and coal). Outputs from the model include energy flows by fuel, investment needs and costs, greenhouse gas emissions and end-user prices.

The GEC is a data-intensive model covering the whole global energy system. Much of the data on energy supply, transformation and demand, as well as energy prices is obtained from the IEA's own databases of energy and economic statistics (https://www.iea.org/data-and-statistics/data-product/world-energy-statistics) and through collaboration with other institutions. The GEC also draws data from a wide range of external sources which are indicated in the relevant sections of the GEC documentation.

The current version of GEC covers energy developments up to 2050 in 27 regions. Depending on the specific module, individual countries are also modelled: 13 in demand; 113 in oil and natural gas supply; and 32 in coal supply (see Annex A of the GEC documentation).

Methane emission estimates

The Global Methane Tracker covers all sources of methane from human activity. For the energy sector, these are IEA estimates for methane emissions from the supply or use of fossil fuels (coal, oil and natural gas) and from the use of bioenergy (such as solid bioenergy, liquid biofuels and biogases). For non-energy sectors – waste, agriculture and other sources – reference values based on publicly available data sources are provided to enable a fuller picture of methane sources.

Upstream and downstream oil and gas

Our approach to estimating methane emissions from global oil and gas operations relies on generating country-specific and production type-specific emission intensities that are applied to production and consumption data on a country-by-country basis. Our starting point is to generate emission intensities for upstream and downstream oil and gas in the United States (Table 1). The US Greenhouse Gas Inventory is used along with a wide range of other publicly-reported, credible data sources. Where scientific studies based on methane measurements provide differing results (e.g. Sherwin et al suggest that US upstream and midstream operations emitted around 21 Mt whereas Williams et al suggest a figure of 15 Mt), we choose the source with the most recent and most comprehensive data. The hydrocarbon-, segment- and production-specific emission intensities are then further segregated into fugitive, vented and incomplete flaring emissions to give a total of 19 separate emission intensities.

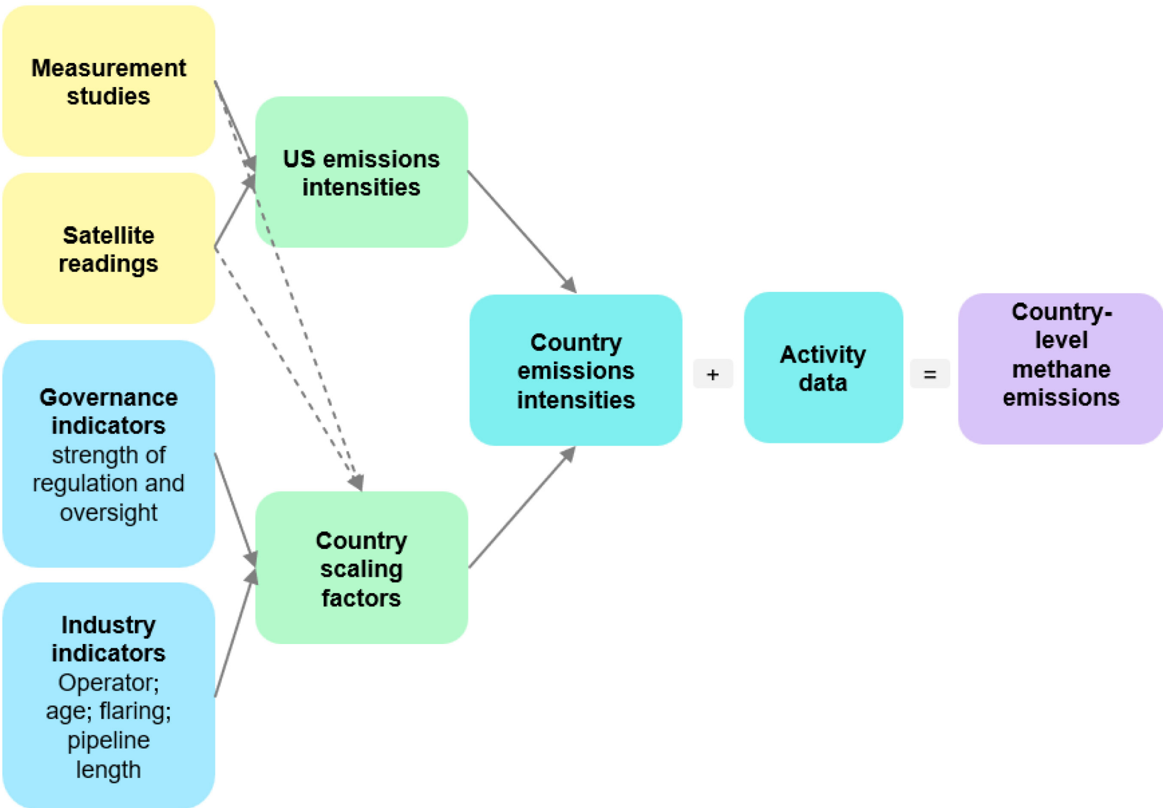
Table 1. Categories of emission sources and emissions intensities in the United States

Hydrocarbon	Segment	Production type	Emissions type	Intensity (mass methane/ mass oil or gas)
Oil	Upstream	Onshore conventional	Vented	0.34%
Oil	Upstream	Onshore conventional	Fugitive	0.09%
Oil	Upstream	Offshore	Vented	0.34%
Oil	Upstream	Offshore	Fugitive	0.09%
Oil	Upstream	Unconventional oil	Vented	0.68%
Oil	Upstream	Unconventional oil	Fugitive	0.17%
Oil	Downstream		Vented	0.014%
Oil	Downstream		Fugitive	0.003%
Oil		Onshore conventional	Incomplete-flare	0.07%
Oil		Offshore	Incomplete-flare	0.02%
Oil		Unconventional	Incomplete-flare	0.08%
Natural gas	Upstream	Onshore conventional	Vented	0.29%

Hydrocarbon	Segment	Production type	Emissions type	Intensity (mass methane/ mass oil or gas)
Natural gas	Upstream	Onshore conventional	Fugitive	0.13%
Natural gas	Upstream	Offshore	Vented	0.29%
Natural gas	Upstream	Offshore	Fugitive	0.13%
Natural gas	Upstream	Unconventional gas	Vented	0.65%
Natural gas	Upstream	Unconventional gas	Fugitive	0.29%
Natural gas	Downstream		Vented	0.18%
Natural gas	Downstream		Fugitive	0.12%

The US emissions intensities are scaled to provide emission intensities in all other countries. This scaling is based upon a range of auxiliary country-specific data, including available satellite data and measurement studies. For the upstream emission intensities, the scaling is based on the age of infrastructure, types of operator within each country (namely international oil companies, independent companies or national oil companies) and average flaring intensity (flaring volumes divided by oil production volumes). For downstream emission intensities, country-specific scaling factors were based upon the extent of oil and gas pipeline networks and oil refining capacity and utilisation.

Methodological approach for estimating methane emissions from oil and gas supply



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The strength of regulation and oversight, incorporating government effectiveness, regulatory quality and the rule of law as given by the Worldwide Governance Indicators compiled by the World Bank, affects the scaling of all intensities. Some adjustments were made to the scaling factors in a limited number of countries to account for other data that were made available (where this was considered sufficiently robust), such as comprehensive measurement studies. This includes data on satellite-detected large emitters and "basin-level inversions", which use satellite readings to assess methane emissions across a wider oil and gas production region, based on data processing by Kayrros, an earth observation firm (see Box 1). It also includes specific policy efforts to control methane emissions from the oil and gas sectors, as tracked in the IEA Policies Database.

Table 2 provides the resultant scaling factors in the top oil and gas producers (the countries listed cover 90% of global oil and gas production). These factors are directly used to modify the emissions intensities in Table 1. For example, the vented emission intensity of onshore conventional gas production in the Russian Federation (hereafter "Russia") is taken as 0.29% × 1.1 = 0.34%. These intensities are finally applied to the production (for upstream emissions) or consumption (for downstream emissions) of oil and gas within each country.

Table 2. Scaling factors applied to emission intensities in the United States

Country	Oil & gas production in 2024	Oil		Gas	
	mtoe	Upstream	Downstream	Upstream	Downstream
United States	1 750	1.0	1.0	1.0	1.0
Russia	1 069	1.7	1.5	1.1	0.8
Saudi Arabia	618	0.6	0.4	0.4	0.3
Canada	458	0.9	0.8	0.9	0.8
Iran	446	2.6	1.3	1.4	0.9
China	426	1.1	0.8	0.8	0.7
United Arab Emirates	250	1.3	0.8	1.1	0.6
Iraq	233	1.2	1.3	0.8	0.6
Qatar	233	1.1	0.7	0.9	0.6
Norway	203	0.0	0.1	0.0	0.1
Brazil	199	1.2	2.0	1.2	1.1
Algeria	155	3.7	2.2	1.8	1.6
Australia	150	0.6	0.5	0.4	0.5
Kuwait	150	1.1	0.7	0.9	0.6
Mexico	131	1.5	1.5	1.1	0.9
Nigeria	117	3.9	4.6	2.5	1.9
Kazakhstan	116	1.3	2.1	1.1	0.9
Malaysia	92	2.1	1.3	1.4	1.2

Country	Oil & gas production in 2024	Oil		Gas	
	mtoe	Upstream	Downstream	Upstream	Downstream
Oman	90	1.6	1.0	0.9	0.7
Turkmenistan	83	11.5	5.0	5.7	4.3
Egypt	82	1.9	1.1	1.0	0.8
Indonesia	80	2.6	2.3	1.5	1.4
Argentina	78	2.7	2.1	1.9	1.5
Libya	72	2.3	3.5	1.2	1.2
Venezuela	70	9.7	7.1	4.2	2.8

These data sources are also used to calculate emissions for past years. Changes in the types of operators, age of facilities, flaring intensities, satellite-detected large emissions as well as governance indicators and methane policies and regulations in place affect the scaling of intensities for historical years.

Box 1 Integrating emissions estimates from satellites

The Global Methane Tracker integrates results from all publicly-reported, credible sources where data has become available. This includes emissions detected by satellites. Changes in the atmospheric concentration of methane can be used to estimate the rate of emissions from a source that would have caused such a change. This is done based on data processing by Kayrros, an earth observation firm, to convert readings of concentrations to identify large sources of emissions from oil and gas operations. Reported emissions encompass methane sources above 5 tonnes per hour.

Oil and gas emissions detected by satellites are reported as a separate item within the Methane Tracker. These estimates are based on a conservative scaling up of emission events directly detected to account for the number of days within the year when observations could be made. This is carried out for all regions where observations were possible for at least 10 days in the year.

The ever-increasing availability of satellite data and information continues to improve global understanding of methane emissions levels and the opportunities to reduce them. However, satellites do have some limitations:

- Existing satellites struggle to provide measurements over equatorial regions, northern areas, mountain ranges, snowy or ice-covered regions or for offshore operations. This means there are many major production areas where emissions cannot be observed.
- Existing satellites should be able to provide daily methane readings globally, but this is not always possible due to cloud cover and other weather conditions. In 2024, there were around 50 countries where methane emissions from oil and gas operations could be detected for at least 10 days. Large emission events were observed in just over 20 of these countries. Coverage tends to be best in the Middle East, Australia and parts of Central Asia, where direct measurements could be made every three to five days. On the remaining days, cloud cover or other interference prevented measurement operations.
- The process of using changes in the atmospheric concentration of methane to estimate emissions from a particular source can rely on significant auxiliary data and be subject to a high degree of uncertainty.

The satellite readings included in the Global Methane Tracker currently provide data only for large emissions sources. This is, of course, subject to a high degree of uncertainty, but ensures that country-by-county estimates provide a comprehensive picture of all methane emissions sources. As additional data become available from measurement campaigns – whether recorded from ground or aerial processes or by satellites – these will be incorporated into the Global Methane Tracker and estimates adjusted accordingly.

Incomplete combustion of flares

Our approach to estimating methane emissions from flaring relies on generating country-specific and production type-specific combustion efficiencies that are applied to flaring data on a country-by-country basis. Global estimates of flared volumes of natural gas are based on reported data from the World Bank's Global Gas Flaring Reduction Partnership.

Combustion efficiency can decrease as a result of lower production rates, high and variable winds, and poor maintenance resulting from a lack of regulatory policy, enforcement or company policy (Johnson, Wilson and Kostiuk, 2001; Kostiuk, Johnson and Thomas, 2004). We estimate combustion based on a range of auxiliary country-specific data:

- Oil production type (unconventional onshore, conventional onshore and offshore), company type and production start-up year (based on Rystad Energy UCube data). Company types are grouped into Majors (ExxonMobil, Chevron, BP, Royal Dutch Shell, Eni SpA, TotalEnergies, and ConocoPhillips), National Oil Companies (NOCs) and Other (e.g. Independent, Private Equity). Maintenance levels to improve flaring combustion efficiencies were applied separately by company type assuming that Majors face greater scrutiny from investors and the public compared to NOCs or Other companies.
- Flaring design standards API 521 and API 537 were considered gauge flare stack sizes, assuming best-case design and optimal flare parameters during early production time.
- The impact of wind speed was incorporated using NASA's Prediction of Worldwide Energy Resources (POWER) Meteorology Data Access Viewer (NASA, 2021). Onshore wind speeds were assessed at 10m of height and offshore wind speeds at 50m of height to reflect closest height of flare stacks in actual facility design. Wind speed variability and its impact on combustion efficiency was incorporated corresponding to the location of production.
- The World Bank's Worldwide Governance Indicators database was used as the basis to assess the general strength of regulatory oversight.

Adjustments are made to consider data on satellite-detected large emitters and specific policy efforts to control methane emissions from the oil and gas sectors, as tracked in the IEA Policies Database. Countries with stronger flaring regulation and strong regulatory oversight are calibrated assuming companies were mandated to quickly inspect and repair any malfunctioning or poor performing flare sites. Countries with weak flaring regulation and low levels of oversight are assumed to perform little to no additional maintenance.

Abandoned oil and gas wells

Our approach to estimating methane emissions from abandoned oil and gas wells relies on estimating the number of abandoned oil and gas wells at a country level, and generating country-specific and production type-specific emissions intensities. Existing measurements of emissions cover a limited number of facilities and regions, and reliable data on abandoned wells is not available for most countries. This is an area with very high levels of uncertainty and our estimates will continue to be updated as the evidence base grows.

There are data sources providing estimates of the current number of abandoned oil and gas wells in some countries. These include the Oil and Gas Infrastructure Mapping database (Gautam, 2023), scientific studies (e.g. Song et al, 2020), and official sources (e.g. US EPA, 2024). These sources generally do not include undocumented wells, so actual values may be higher than currently reported. To estimate the number of abandoned wells historically and in countries for which no data exists, we use historical changes in production and assume a natural decline rate of 35% for tight and shale resources, and 8% for other resources. If production is greater than the decline given by these rates, we assume new wells have been developed and will continue operating for their typical lifespan (five years for tight and shale resources, 25 years for other resources).

Most abandoned wells do not emit significant volumes of methane. Wells that intentionally vent emissions, were improperly plugged and abandoned or have lost integrity are more likely to be significant sources of emissions. Emissions in the year after abandonment from onshore oil and gas wells, tight oil and shale gas wells, and shallow offshore facilities in the United States (Table 3) are based on scientific studies (e.g. Riddick et al, 2024; Williams, Regehr and Kang, 2020) as well as other publicly-reported, credible data sources. Riddick et al indicate that recently-producing wells tend to emit more than older ones and we assume that emissions per well fall by 2% per year after abandonment.

Table 3. Initial annual emissions from abandoned wells in the United States

Hydrocarbon	Production type	Emissions (kt CH4/well)
Oil	Onshore	0.2
Oil	Tight oil	0.3
Oil	Shallow offshore	0.003
Natural gas	Onshore	0.4
Natural gas	Tight gas and shale gas	0.5
Natural gas	Shallow offshore	0.005

Notes: These intensities refer to the amount of methane that reaches the atmosphere. While deep offshore wells may emit significant volumes of methane emissions, these are unlikely to reach the sea surface as the methane dissolves in the water column and is oxidized by microbes.

The strength of regulation and oversight – as measured by government effectiveness, regulatory quality and rule of law according to the World Bank's Worldwide Governance Indicators (WGI) – affects the country-level scaling of these intensities. This scaling also reflects specific policy efforts to control methane emissions from oil and gas, as tracked in the IEA Policies Database.

Coal mine methane

The IEA's estimates of coal mine methane (CMM) emissions are derived from mine-specific or region-specific emissions intensities for Australia, the People's Republic of China (hereafter "China"), India and the United States (which collectively account for around 75% of global coal production). Emission intensities for coal mines in the United States are based on the latest US Environmental Protection Agency's Greenhouse Gas Reporting Program and US Greenhouse Gas Inventory. Emission intensities for coal production in Australia are based on its latest National Inventory Reports. This is supplemented by data sources that provided disaggregated CMM data for China (Wang et al., 2018; Zhu et al., 2017) and India (Singh A. K. and Sahu J. N., 2018) (India Ministry of Coal, 2018).

The mine-level CMM estimates generated in this way are aggregated, verified and calibrated against country-level estimates taken from satellites and atmospheric readings (e.g. Shen et al., 2023; Deng et al., 2022; Miller et al., 2019). Methane emissions are calculated separately for the three main coal types in the Global Energy and Climate Model: steam coal, coking coal and lignite (see Table 3 for a summary of intensities). Methane emissions from peat mining are likely to be relatively small and are not included in this analysis.

Based on these data, coal quality, mine depth and regulatory oversight are used to estimate CMM emission intensities for mines in other countries for which there are no reliable measurement-based estimates. The World Bank's Worldwide Governance Indicators database as used as the basis to assess the general strength of regulatory oversight alongside policies related to coal mine methane tracked in the IEA's Policies Database. The emissions intensities also consider estimates from satellite-detected large emitters and basin-level emissions for coal producing regions, based on data processing by Kayrros.

The depth and type (surface or underground) of individual mines in operation around the world, as well as the associated coal resource (thermal or metallurgical) and methane gas content, is based on the GEM Global Coal Mine Tracker and the CRU database. Deeper coal seams tend to contain more methane than shallower seams, while coal of higher rank (e.g. anthracite) has higher methane content than coal of lower rank (e.g. lignite). In the absence of any mitigation measures, methane emissions to the atmosphere will therefore tend to be higher for underground mines than for surface mines. Mines that have both surface and underground operations are classified as underground. Mines that produce both thermal and metallurgical coal are classified on a country-by-country level to match IEA country-level data on coal production.

Table 4. Emissions intensities of major coal producers (kg CH_4/tonne of coal equivalent)

Region	Steam coal	Coking coal	Lignite
Australia	3.6	5.2	0.7
China	5.4	12.4	-
India	3.4	5.1	0.4
Indonesia	4.1	7.8	-
Russia	10.5	15.6	2.7
South Africa	7.4	5.3	-
United States	5.1	11.2	0.4

Note: Coking coal is the same as metallurgical coal. Intensities reflect average mine characteristics in each region (mine depth, coal quality and regulatory oversight, including available province or state-level information).

Resulting estimates of global CMM emissions amount to around 40 Mt (for 2024), within the range of other modelling efforts. Methane intensities for coking coal are generally higher because production comes from deeper mines with coal deposits of higher rank. Differences between input sources and IEA estimates can result from auxiliary data (e.g. satellite-based measurements) or activity data. For example, the IEA estimate for Australian CMM emissions is about 1.7 Mt (for 2024), above the official submission to the UNFCCC of 1.0 Mt (for 2022). This difference is mostly driven by auxiliary data, including data from studies indicating higher fossil emissions based on satellite inversions. Intensities vary significantly according to mine characteristics within each country (e.g. Australia's coking coal methane intensity is estimated to be relatively small as most of its production comes from low-depth mines with lower methane content).

Abandoned mine methane

Our approach to estimating methane emissions from abandoned mines relies on generating estimates of abandoned coal capacity and applying country-specific and production type-specific emissions intensities. Reliable data on abandoned mines (e.g. year of closure, condition of the mine, area covered) is not available for most countries and existing measurements of methane emissions from abandoned mines cover a very limited number of facilities and regions. This is an area with very high levels of uncertainty and our estimates will continue to be updated as the evidence base grows.

To estimate abandoned coal mine capacities, we start with historical changes in production for each production type and assume a decline rate of 5%. If production in any year is greater than this decline rate, we assume new capacity has been added. We assume that mines have a typical lifespan of 30 years and may add new capacity up to five years before closure.

Estimates of emission intensities for steam coal, coking coal and lignite facilities (Table 5) are based on scientific studies (e.g. Kholod et al, 2020; Chen et al, 2024) as well as the GEM Global Coal Mine Tracker and other publicly-reported, credible data sources.

Table 5. Initial emissions intensities of abandoned mines

Coal type	Emissions (t CH_4/ktce)
Steam coal	3.0
Coking coal	4.5
Lignite	0.3

Note: ktce = thousand tonnes of coal equivalent of retired capacity.

Methane emissions from abandoned mines depend on mine characteristics and mitigation measures. Abandoned surface mines usually do not present a significant source of emissions, so we only apply these emissions factors to retired coal capacity associated with underground mines. Mines may become flooded over time, limiting methane emissions (Kholod et al, 2020), and we assume that emissions per unit of capacity decline by around 30% per year after abandonment.

Some facilities use methane capture projects to minimise their emissions or integrate measures to limit emissions through mine sealing or flooding. Such measures may relate to closure plans and other elements of regulatory frameworks. Therefore, the strength of regulation and oversight – as measured by government effectiveness, regulatory quality and the rule of law according to the World Bank's Worldwide Governance Indicators – affects the country-level scaling of these intensities. This scaling also reflects specific policy efforts to control methane emissions from coal, as tracked in the IEA Policies Database.

Emissions from fuel combustion (end use)

Methane emissions are associated with fuel use, either due to incomplete combustion or as fugitive emissions. Methane can leak from storage vessels, pipelines or end use appliances (e.g. stovetops). It can also escape without combustion from mobile applications (e.g. natural gas fuelled vehicles) or stationary applications (e.g. power generators).

We estimate that nearly 20 Mt of methane emissions result from the incomplete combustion of biomass used for cooking or heating, mostly in emerging market and developing economies. Among fossil fuels, we estimate that about 3 Mt (2% of energy-related methane emissions) originate from the end use of coal, oil products and natural gas. This estimate is based on the emissions factors published by the Intergovernmental Panel on Climate Change (IPCC) for energy consumption by households, industries and the transport sector.

Methane emissions from the use of fuels in stationary and mobile applications are estimated using the latest regional data available from the IEA's Greenhouse Gas

Emissions from Energy database. The Tier 1 methodology from the 2006 IPCC Guidelines for greenhouse gas (GHG) inventories have been adopted for the purpose of estimating the non-CO_2 emissions from fuel combustion. Unlike CO_2, the non-CO_2 greenhouse gas emissions from fuel combustion are strongly dependent on the technology used. Since the technologies applied in each sector vary considerably, the guidelines do not provide default emission factors for these gases based on fuels only. Sector-specific Tier 1 default emission factors can provide a reasonable estimate for these emissions.

Some measurement campaigns have suggested that these emissions factors could significantly underestimate actual emissions across different end-use environments, including in industries, cities and households. Emission levels might also have changed in recent years. These are areas with very high levels of uncertainty and our estimates will continue to be updated as the evidence base grows.

For estimating the emissions corresponding to stationary combustion, the default Tier 1 non-CO_2 emission factors provided in the 2006 IPCC guidelines assume effective combustion in high temperature. The emission factors provided for methane are based on the 1996 IPCC Guidelines and have been established by a large group of inventory experts. However, due to the absence of sufficient measurements and since the concept of conservation of carbon does not apply in the case of non-CO_2 gases, the uncertainty range associated with these estimates is set at a factor of three.

Similarly for mobile combustion, the non-CO_2 emission factors are more difficult to estimate accurately than those for CO_2, as they will depend on vehicle technology, fuel and operating characteristics, mainly the combustion and emission control system of the vehicles. Thus, default fuel-based emission factors are highly uncertain. However, the Tier 1 method does allow using fuel-based emission factors if it is not possible to estimate fuel consumption by vehicle type.

For more details on the underlying methodology and assumptions please refer to the IEA GHG emissions from energy documentation.

Emissions from biogas supply

Our approach to estimating methane emissions from global biogas and biomethane production relies on generating country-specific and segment-specific emission intensities that are applied to production data on a country-by-country basis. Existing measurements on these sources cover a limited number of facilities and regions. This is an area with very high levels of uncertainty and our estimates will continue to be updated as the evidence base grows.

Our starting point is to generate emission intensities for biogas production and upgrading (Table 6). Scientific studies (e.g. Wechselberger et al, 2023; Bakkaloglu et al, 2024) are used along with other publicly-reported, credible data sources (e.g. European Commission: Joint Research Centre, 2024).

Table 6. Emissions intensities of biogas and biomethane supply

Supply segment	Supply type	Intensity
Production	Micro digesters	11%
Production	Industrial digesters with open digestate storage	6.3%
Production	Industrial digesters with closed digestate storage	2.9%
Upgrading	Water scrubbing	2.9%
Upgrading	Chemical absorption	0.5%
Upgrading	Other technologies	2.1%

Notes: Assumes methane has an energy density of 55 megajoules per kilogramme. Micro digesters are small-scale, farm-level digesters. Other technologies used to upgrade biogas to biomethane include membranes, pressure swing adsorption and physical absorption.

Methane emissions from biogas and biomethane supply can occur all along the supply-chain, including in substrate receiving and storage, biodigesters, digestate storage, upgrading units as well as leakage from storage tanks, connections and processing rooms. The intensities detailed above reflect typical emission sources from production and upgrading.

Some facilities take steps to minimise emissions, including leak detection and repair campaigns and regenerative thermal oxidisers. These measures are often tied to regulatory requirements that cap leakage rates, require regular measurements or otherwise incentivise methane abatement. These types of policies and regulations affect the country-level scaling of these intensities. We have identified several European countries that apply such requirements, including Denmark, France, Germany and Sweden (European Biogas Association, 2023).

These intensities are then multiplied by biogas and biomethane production (in energy terms) by country to derive methane emissions from these sources. The amount of production coming from each supply type listed above is estimated based on data from the IEA's Technology Collaboration Programme on Bioenergy along with other publicly-reported, credible data sources (e.g. US EPA, 2024) and expert input.

Waste and agriculture

The Global Methane Tracker includes emissions estimates from non-energy sectors – waste, agriculture and other sources – based on publicly available data sources, to provide a fuller picture of methane sources from human activity. Reference estimates are taken as an average of estimates available for the most recent year from 2019-2024, based on the following sources.

United Nations Framework Convention on Climate Change (UNFCCC) – National greenhouse gas inventories submitted to the Climate Change secretariat. These submissions are made in accordance with relevant reporting requirements, such as the UNFCCC reporting guidelines on annual greenhouse gas inventories. The inventory data are provided in the annual greenhouse gas inventory submissions by Annex I Parties and in the national communications and biennial update reports by non-Annex I Parties. Data available here.

Emissions Database for Global Atmospheric Research – EDGAR is a global database of anthropogenic emissions of greenhouse gases and air pollution. EDGAR provides independent emission estimates compared to what is reported by Parties under the UNFCCC, using international statistics and a consistent IPCC methodology. Additional information can be found in Crippa et al. (2021). Data available here.

Community Emissions Data System – CEDS produces consistent estimates of emissions over the industrial era (1750 - present). It uses a variety of data to do so, including population and energy statistics, emissions inventories and other auxiliary data. Note that EDGAR is among the sources used to establish emissions factors for non-combustion sources. Further information on CEDS methodology and sources is available in Hoesly et al. (2018) and here. Data available here.

Climate Watch (CAIT) – CAIT draws on climate-relevant data from research centres, government agencies, and international bodies, including the U.N. Food and Agriculture Organization (FAO, 2022) and the U.S. Environmental Protection Agency. The CAIT Historical GHG Emissions data contains sector-level greenhouse gas emissions data for 194 countries for the period 1990-2020, including emissions of the six major greenhouse gases from most major sources and sinks. Further information can be found here. Data available here.

These datasets were aligned with the Global Methane Tracker's categories and regions by examining every major emitter and every source of anthropogenic emissions included in each database.

Methane abatement estimates

The Global Methane Tracker includes abatement cost curves for methane emissions from oil and gas production as well as coal mining. Unfortunately, the publicly available data on methane mitigation is limited. While hundreds of mitigation projects exist across the fossil fuel industry, most do not provide abatement data and related costs details. Our approach looks to reconcile all available information in a consistent and transparent manner.

In 2024, the IEA published its Methane Abatement Model, which allows users to estimate oil and gas methane abatement potential and the associated cost of abatement by country, segment and reduction technology. The source code for the model is hosted as a public project on GitLab and an outline tutorial provides in-depth instructions for using the tool. We welcome feedback on the model as well as contributions based on robust data sources that can support further refinements to the estimates of abatement potential and costs.

Marginal abatement cost curves for oil and gas

To construct the marginal abatement cost curves presented in the Methane Tracker Data Explorer, the 19 emissions sources listed in Table 1 were further separated into 82 equipment-specific emissions sources (Table 7),[1] with allocations generally based on proportions from the United States. However several modifications were made for countries based on other data sources and discussions with relevant stakeholders. Some of the largest changes made were for the proportion of emissions from pneumatic controllers (which are less prevalent outside North America), LNG liquefaction (assumed to be larger in LNG exporting countries) and associated gas venting.

Table 7. Equipment-specific emissions sources in the marginal abatement cost curves

Equipment source	Hydrocarbon	Segment
Gas Engines	Oil	Upstream
Large Tanks w/VRU	Oil	Upstream
Large Tanks w/o Control	Oil	Upstream
Heaters	Oil	Upstream
Small Tanks w/o Flares	Oil	Upstream
Malfunctioning Separator Dump Valves	Oil	Upstream
Pneumatic Devices, High Bleed	Oil	Upstream

[1] To aid visualisation of the marginal abatement cost curves, the costs and savings from multiple technologies are generally aggregated together. Within each country, abatement options for each of the 19 emission sources are aggregated into three cost categories: the lowest 50%, the middle 30% and the highest 20%.

Equipment source	Hydrocarbon	Segment
Pneumatic Devices, Low Bleed	Oil	Upstream
Pneumatic Devices, Int Bleed	Oil	Upstream
Chemical Injection Pumps	Oil	Upstream
Vessel Blowdowns	Oil	Upstream
Compressor Blowdowns	Oil	Upstream
Compressor Starts	Oil	Upstream
Associated Gas Venting	Oil	Upstream
Well Completion Venting (less HF Completions)	Oil	Upstream
Well Workovers	Oil	Upstream
HF Well Completions, Uncontrolled	Oil	Upstream
HF Well Completions, Controlled	Oil	Upstream
Pipeline Pigging	Oil	Upstream
Well Drilling	Oil	Upstream
Produced Water	Oil	Upstream
Well Blowouts Onshore	Oil	Upstream
Pressure Relief Valves	Oil	Upstream
Tanks	Oil	Downstream
Truck Loading	Oil	Downstream
Marine Loading	Oil	Downstream
Rail Loading	Oil	Downstream
Pump Station Maintenance	Oil	Downstream
Pipeline Pigging	Oil	Downstream
Uncontrolled Blowdowns	Oil	Downstream
Combustion	Oil	Downstream
Process Vents	Oil	Downstream
CEMS	Oil	Downstream
Glycol Dehydrator	Gas	Upstream
Produced Water	Gas	Upstream
Gas Well Completions without Hydraulic Fracturing	Gas	Upstream
Gas Well Workovers without Hydraulic Fracturing	Gas	Upstream
Hydraulic Fracturing Completions and Workovers that vent	Gas	Upstream
Hydraulic Fracturing Completions and Workovers with RECs	Gas	Upstream
Well Drilling	Gas	Upstream
Pneumatic Device Vents (Low Bleed)	Gas	Upstream
Pneumatic Device Vents (High Bleed)	Gas	Upstream
Pneumatic Device Vents (Intermittent Bleed)	Gas	Upstream
Chemical Injection Pumps	Gas	Upstream

Equipment source	Hydrocarbon	Segment
Kimray Pumps	Gas	Upstream
Dehydrator Vents	Gas	Upstream
Large Tanks w/VRU	Gas	Upstream
Large Tanks w/o Control	Gas	Upstream
Heaters	Gas	Upstream
Separators	Gas	Upstream
Gas Engines	Gas	Upstream
Well Clean Ups (LP Gas Wells) - Vent Using Plungers	Gas	Upstream
Well Clean Ups (LP Gas Wells) - Vent Without Using Plungers	Gas	Upstream
Vessel BD	Gas	Upstream
Pipeline BD	Gas	Upstream
Compressor BD	Gas	Upstream
Compressor Starts	Gas	Upstream
Gathering and Boosting Stations	Gas	Upstream
Pressure Relief Valves	Gas	Upstream
Gas Turbines	Gas	Upstream
Recip. Compressors	Gas	Upstream
Centrifugal Compressors (wet seals)	Gas	Upstream
Centrifugal Compressors (dry seals)	Gas	Upstream
Dehydrators	Gas	Upstream
AGR Vents	Gas	Upstream
Pneumatic Devices	Gas	Upstream
Blowdowns/Venting	Gas	Upstream
Reciprocating Compressor	Gas	Downstream
Centrifugal Compressor (wet seals)	Gas	Downstream
Centrifugal Compressor (dry seals)	Gas	Downstream
Generators	Gas	Downstream
Dehydrator vents (Transmission)	Gas	Downstream
Dehydrator vents (Storage)	Gas	Downstream
Pneumatic Devices (High Bleed)	Gas	Downstream
Pneumatic Devices (Intermittent Bleed)	Gas	Downstream
Pneumatic Devices (Low Bleed)	Gas	Downstream
Pipeline venting	Gas	Downstream
Station Venting Transmission	Gas	Downstream
Station Venting Storage	Gas	Downstream
LNG Engines	Gas	Downstream
Pressure Relief Valve Releases	Gas	Downstream
Pipeline Blowdown	Gas	Downstream

The abatement options included in the marginal abatement cost curves to reduce emissions from these sources are listed in Table 8. Every abatement option has a specific capital cost, which is annualised based on the number of years it is expected to last. These are added to yearly operational costs, which include wages, maintenance and related expenditures. Costs were again based upon information from the United States. However, labour costs, whether the equipment is imported or manufactured domestically (which impacts the capital costs and whether or not import taxes are levied), and capital costs were adjusted based on country-specific or region-specific information using data from the International Labour Organization, Bloomberg (2024) and the World Trade Organization. Similarly, applicability factors are modified based on other available information (for example, that the use of solar-powered electric pumps is more limited in high-latitude countries).

Table 8. Abatement options for methane emissions from oil and gas operations

Abatement option
Blowdown Capture (per Compressor)
Blowdown Capture (per Plant)
Improve flaring-Completion
Improve flaring-Portable
Improve Flaring-Portable Completions Workovers without Hydraulic Fracking
Improve Flaring-Portable WO Plunger Lifts
Install New Methane Reducing Catalyst in Engine
Install Non-Mechanical Vapor Recovery Unit
Install Plunger Lift Systems in Gas Wells
Install Vapor Recovery Units
Install Electronic Flare Ignition Devices
Install Automated Air-Fuel Ratio Controls
Mechanical Pumping for Liquids Unloading
Pipeline Pump-Down Before Maintenance
Redesign Blowdown Systems and Alter ESD Practices
Reduced Emission Completion
Replace Kimray Pumps with Electric Pumps
Replace Pneumatic Chemical Injection Pumps with Electric Pumps
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps
Replace with Instrument Air Systems
Replace with Electric Heater
Replace with Electric Motor
Replace with Servo Motors
Replace with Solenoid Controls

Abatement option
Replacement of Reciprocating Compressor Rod Packing Systems
Route to Existing Flare - Large Dehydrators
Route to Existing Flare - Large Tanks
Route to Flare - Small Dehydrators
Route to Existing Flare - Small Tanks
Route Vent Vapors to Tank
Wet Seal Degassing Recovery System for Centrifugal Compressors
Wet Seal Retrofit to Dry Seal Compressor
Advanced AGR
Microturbine
Mini-LNG
Mini-GTL
Mini-CNG
Monitor and plug abandoned wells
Annual LDAR
Biannual LDAR
Quarterly LDAR
Continuous LDAR
Daily LDAR

Leak detection and repair (LDAR) programmes are the main mechanisms for mitigating fugitive emissions along the production, transmission and distribution segments of the value chain. The costs of carrying out inspections and undertaking repairs differ depending on the segment in question, since it takes longer to inspect a compressor on a transmission pipeline than in a production facility. It is assumed that inspections can be carried out annually, twice a year, quarterly, daily, or be based on continuous monitoring systems, with each option included as a separate mitigation option in the marginal abatement cost curves. Daily LDAR is used to tackle emissions from large leaks that occur sporadically such as those detected by satellites. Annual inspections are assumed to mitigate 40% of fugitive emissions, biannual inspections mitigate 60%, quarterly inspections mitigate 75%, and a continuous LDAR programme reduces fugitive emissions by 90%; based on current technology, it is assumed that the remaining 10% cannot be avoided.

In our marginal abatement cost curve, we have grouped these abatement options into several categories. We have also associated each abatement option with policy measures that target those actions. The abatement and policy options that appear in the marginal abatement cost curves are described in further detail in the glossary below.

Box 2 Policies Database and Policy Explorer

The Global Methane Tracker incorporates information from the IEA's Policies Database. This cross-agency database brings together information on past, existing or planned government policies and measures covering many topics across the energy sector, including energy efficiency, renewables, technology innovation and methane abatement.

The entries in the Policies Database related to methane abatement are categorised by policy type and by sector. For each entry, we have included a brief description, links to original source material and other information about the measure. This information is based on a broad review of policy and regulatory measures in place across the world. We have identified different measures through desktop research and through discussions with governments. As of the release of the Global Methane Tracker 2025, this database has more than 500 entries including in-depth information on policies in place in 25 countries and more limited information on many more. The policy explorer shows 16 different types of policies, which are categorised by the primary regulatory approach: prescriptive, performance-based, economic, or information-based. Detailed definitions for these categories and policy types can be found in the glossary. We welcome feedback regarding any updates to existing policies or on additional policies that are missing from the database.

Well-head prices used in net present value calculation

Since natural gas is a valuable product, the methane that is recovered can often be sold. This means that deploying certain abatement technologies can result in overall savings if the net value received for the methane sold is greater than the cost of the technology. Well-head prices are used in each country to determine the value of the methane captured. As described in the IEA's World Energy Outlook 2019, marginal abatement cost curves reflect this issue from a global, societal perspective. Any credit obtained for selling the gas is applied regardless of the contractual arrangements and prices assume that there are no domestic consumption subsidies (as the gas could be sold for a higher price on international markets). The well-head gas prices used could therefore be substantially different from subsidised domestic gas prices.

Representative natural gas import prices from 2024 are the starting point for the well-head prices within each country. To estimate well-head prices over time, each country is designated as either an importer or an exporter, based on the trends seen in the Stated Policies Scenario. For importing countries, any gas that would be saved from avoiding leaks would displace imports. The well-head price is taken as the import price minus the cost of local transport and various taxes (assumed to be around 35% of the import price). For exporting countries, the relevant well-head price is taken as the import price in their largest export market, netted back to the emissions source. In calculating the net-back, allowances are made for transport costs (including liquefaction and shipping or pipeline transport), fees and taxes. For example, in Indonesia the export price is taken as the import price in Japan: USD 11 per million British thermal units (MBtu) based on average 2024 prices. Export taxes are then subtracted, along with a further USD 1.5/MBtu to cover the cost of liquefaction and shipping. This gives a well-head gas price in Indonesia of about USD 6/MBtu. In the United States and Canada, the well-head price is taken as the benchmark (Henry Hub) gas price minus 35% (to cover the cost of local transportation and fees).

The costs and revenue for each technology or abatement measure are converted into net present value using a discount rate of 8% and divided by the volume of emissions saved to give the cost in USD per MBtu.

To reflect the volume of natural gas that would be lost, we assume a methane content of 83% for well-head flows of natural gas. Methane is assumed to have an energy density of 36 MJ/m^3 and density of 0.68 kg/m^3, meaning that 1 tonne of methane is about 50 MBtu.

Marginal abatement cost curves for coal mine methane

To construct marginal abatement cost curves for coal mine methane (CMM), emission estimates at the mine level are split into specific sources of emissions, according to the type of mine (see Table 9). Sources of emissions include vented emissions (i.e. intentional emissions, often for safety reasons, due to the design of the facility or equipment), emissions due to incomplete combustion (i.e. methane slips from flares, engines, boilers or oxidation systems) and fugitive emissions (i.e. unintentional emissions).

Table 9. Emissions sources in thermal and coking coal mines

Type	Specific source	Underground	Surface
Vented	Ventilation systems	60%	0%
Vented	Drainage systems	25%	15%
Incomplete combustion	Other losses	2%	1%
Fugitive	Other losses	5%	1%
Fugitive	Post-mining	3%	8%
Fugitive	Outcrops, workings	5%	75%
Total	**Total**	**100%**	**100%**

Note: Outcrops, workings includes unsealed mine entries.

Ventilation systems. The main source of methane from underground mines is ventilation shafts that release air into the atmosphere.

Drainage systems. These are used to drain coal seams in advance of mining (pre-drainage) and to drain coal seams and strata after by mining (post-drainage). Pre-drainage can include vertical or horizontal wells drilled into coal seams or adjacent gas-bearing strata to extract associated methane. Post-drainage can be achieved from vertical, inclined and horizontal boreholes drilled over longwalls or strata. The gas is generally drained to surface pumping stations where it can be vented, flared or prepared for utilisation or sale to third parties. In some instances, it is vented underground and mixed with the ventilation air.

Other losses. These are associated with methane released from the potential gas infrastructure of methane projects installed on a mine, whether pre-operational, operational or decommissioned. They include methane resulting from incomplete combustion (e.g. at flares or utilization units) and fugitive emissions (e.g. pipeline leaks).

Post-mining. Activities such as processing, storage and transport, where quantities of methane still trapped in the matrix of the coal can seep out. This includes methane released from waste heaps due to desorption from the methane-bearing coal matter.

Outcrops and workings. These are the main sources of methane at surface mines, where shallow areas being explored often have fractured ground above them. They include mine entrances and emissions migrating to the surface from gas-bearing strata through cracks or boreholes.

The allocation of emissions to each source is based on existing literature such as: the UN Economic Commission for Europe (UNECE) Best Practice Guidance for Effective Management of Coal Mine Methane at National Level, the Tools and Resources Library of the US Environmental Protection Agency (EPA) Coalbed Methane Outreach Program and input from reviewers. In the absence of region-specific information, the splits in Table 6 are assigned to the emissions by mine type for all countries. The allocation of emissions to drainage systems considers the potential deployment of these in existing mines, including facilities where drainage systems are not currently installed.

For the purposes of developing CMM abatement estimates, we assign an abatement potential and an annual cost for each measure described in the glossary. Key references for the costs, efficiency and applicability of abatement measures include: the EPA's Global Non-CO_2 Greenhouse Gas Emission Projections & Mitigation report and its Methodology, as well as the CMM Cash Flow Model; the Global Methane Initiative's International Coal Mine Methane Projects Database and its Coal Mine Methane Mitigation and Utilization Technologies; the IEA's oil and gas methane abatement model; UNECE's Best Practice Guidance on Ventilation Air Methane Mitigation; and input from reviewers.

Abatement potentials

Table 10 shows the criteria and abatement potential for each measure, according to the type and specific source of emissions. The abatement potential is the product of two factors: the **applicability factor** indicates the share of emissions coming from facilities where it is feasible to deploy abatement measures (e.g. methane concentrations are sufficiently high), while the **effectiveness factor** indicates how much methane each measure abates (e.g. we assume flares would combust 95% of methane emissions on average).

Table 10. How specific sources of emissions are abated and abatement potential of measures

Specific source	Choice of measure	Measure	Type	Applicability factor	Effectiveness factor	Abatement potential
Drainage systems	Emissions <1 kt	Flare	Vented	75%	95%	**71%**
	Other mines	Drained CMM utilisation	Vented	75%	95%	**71%**
Ventilation systems	Intensity <10kgCH_4/t or emissions <10 kt	VAM oxidation	Vented	70%	95%	**67%**
	Other mines	On-site recovery & use	Vented	70%	95%	**67%**
Other losses	All mines	Efficiency improvements	Incomplete combustion	75%	75%	**56%**
Other losses	All mines	Capture and route	Fugitive	50%	75%	**38%**
Post-mining	All mines	Capture and route	Fugitive	25%	60%	**15%**
Outcrops, workings	All mines	Capture and route	Fugitive	10%	60%	**6%**

Note: These potentials are applied to all mines for all countries as more detail at the country-level is not available. Flares are also used to handle the variability of methane flows in CMM utilisation projects. In this sense, this measure is also assigned to 10% of emissions from degasification systems in mines with drained CMM utilisation.

Abatement costs

Costs include both capital and operational expenditures. Capital costs are one-time expenses incurred to implement abatement measures (e.g. purchase of equipment). Operational costs include work salaries, maintenance and related expenditures. Costs for each measure are converted into annual values using a discount rate of 8% and considering the lifetime of the abatement measure.

Table 11. CMM abatement costs and assumptions by abatement measure for a typical mine in the United States

Measure	Capital cost (Million USD)	Operational cost (Million USD)	Lifetime (years)
Flare	1.2	0.1	20
Drained CMM Utilisation	5.1	3.3	20
VAM Oxidation	10.8	1.2	15
VAM on-site recovery and use	11.9	1.4	15
Efficiency improvements	0.16	0.03	15
Capture and route	1.3	0.3	15

Note: Costs and measures vary according to mine characteristics and region. Costs shown here are for a typical site in the United States with annual methane emissions above 0.5 kt and annual coal production below 5 million tonnes

Capital and operational costs for each measure are derived for the United States and scaled to all other countries. Operational and capital costs are modified based on country-specific or region-specific information where available. For example, base capital costs for VAM oxidation are twice as high for mines in Russia and Kazakhstan, as these usually require a system to remove dust from VAM flows. Also, regional power prices affect the annual operational costs of running VAM oxidation units. The prices shown in Table 11 are for a typical site in the United States. Further cost modifications are applied based on the mine characteristics, including regional labour and capital costs.

For drained CMM utilisation, costs also vary according to absolute methane emissions on the assumption that electricity generation and drainage systems would require additional investment, the costs shown above are for a mine emitting around 2.5 kt CH_4/year. The size of gas-fired generators are scaled to the level of absolute emissions, assuming a capacity factor of 75% and the capital costs indicated in the IEA's World Energy Outlook 2024 for a Combined Cycle Gas Turbine Plant (roughly USD 1 000/kW). For example, for a mine with emissions of around 2.5 kt/year of vented emissions that could be abated by drainage systems, we would assume a 2.5 MW facility, costing USD 5.1 million with a collection system and other expenditures (e.g. grid connection, owner's costs, contingencies).

For VAM oxidation or on-site recovery and use, costs are scaled for mines emitting more than 10 kt CH_4/year on the assumption that further abatement equipment would be required.

For capture and route, costs are also scaled for mines with coal production above 5 million tonnes (Mt) per year on the assumption that the size of operations influences expenditure with monitoring and routing implements. For example, the annual costs for the capture and route measure in a mine that produced 8 Mt of coal are 1.6 times higher than those for mines with a production below 5 Mt.

Energy prices used in net present value calculation

Abatement measures provide energy that could avoid the need to purchase electricity or use coal that has been extracted (e.g. on-site recovery and use). They can also provide revenue associated with the sale of energy (e.g. degasification for power generation). This means that deploying certain abatement technologies can result in overall savings if the value generated by the methane used or sold is greater than the cost of the technology.

Measures that do not enable energy use or provide only limited energy gains are not associated with any revenue. This is the case, for example, of flaring and ventilation air methane oxidation.

The marginal abatement cost curves examine potential savings from a global, societal perspective. The credit obtained for energy savings, selling power or additional coal is therefore applied regardless of the contractual arrangements necessary, however, a discount is applied to reflect transport costs, fees and taxes. Prices assume that there are no industry or local consumption subsidies (as the power or coal could be sold on the regional market at a greater price). The energy prices used could therefore be substantially different from facility-level prices.

The economic costs and revenue for each technology or abatement measure are converted into net present value using a discount rate of 8% and divided by the volume of emissions saved to give the cost in USD per gigajoule (GJ). Methane is assumed to have an energy density of 55 MJ/kg and a density of 0.6797 kg/m^3.

Revenues associated with **drained CMM utilisation** are calculated based on 2024 regional electricity prices discounted by 40%. For example, in 2024, electricity prices in the industry in the United States averaged USD 22/GJ, so the revenue for methane savings from drained CMM utilisation are set to USD 13/GJ for mines in the United States (USD 0.05/kWh).

Revenues associated with **VAM on-site recovery and use** are calculated based on average regional coal prices discounted by 33%. For example, in 2023, coal prices in the industry in the United States averaged USD 3/GJ, so the revenue for methane savings from VAM on-site recovery and use are set to USD 2/GJ for mines in the United States.

Revenues associated with the **capture and route** option are calculated based on the abatement measures assigned to each mine. If a mine has the potential for drained CMM utilisation, this will be the reference for revenue calculations, considering the emissions saving of the capture and route option. Otherwise, if a mine has the potential for VAM on-site recovery and use, this will be the reference for revenue calculations. If a mine does not have any of these options, no revenue is associated with the capture and route option.

Projections of energy-related methane emissions and assessed temperature rises

We have carried out analysis using the Model for the Assessment of Greenhouse Gas Induced Climate Change (MAGICC) to assess the impacts of different emissions trajectories on the average global surface temperature rise. MAGICC climate models have been used extensively in assessment reports written by the Intergovernmental Panel on Climate Change. MAGICC 7, the version used in this analysis, is one of the models used for scenario classification in the IPCC's Sixth Assessment Report. Emissions of all energy-related greenhouse gases from the WEO 2024 scenarios are supplemented with commensurate changes in non-energy-related emissions based on the scenario database published as part of the IPCC Special Report on Global Warming of 1.5 °C. All changes in temperatures are relative to 1850-1900 and match the IPCC 6th Assessment Report definition of warming of 0.85 °C between 1995-2014.

An important consideration in assessing temperature rises is the date to examine. If the aim of climate policy is to limit peak warming, then the key factor is the time when the global temperature rise will reach a peak. In the IEA's Net Zero Emissions by 2050 Scenario, global energy-related net CO_2 emissions drop to zero in 2050. This is also the estimated date when increases in global temperatures are expected to peak. We therefore choose to focus our analysis on the temperature rise in 2050.

The Stated Policies and Net-Zero Emissions by 2050 scenarios project methane emissions from fossil fuel operations to 2050. Changes in other non-energy sources of methane are introduced via a process of "infilling" based on the most relevant Shared Socioeconomic Pathway-Representative Concentration Pathway (SSP-RCP) and a quantile rolling windows method from Silicone (Lamboll et al. 2020). For the Stated Policies Scenario, non-energy sources of methane are initially based on SSP 2-4.5.

Differences are then examined in the temperature rise in 2050 between the Stated Policies Scenario and the Stated Policies Scenario with full methane abatement. All other variables, including the other greenhouse gases (such as CO_2, N_2O, HFCs etc.), are kept constant to isolate the impact of the methane abatement policies on the median temperature rise in 2050. Full methane abatement reduces the temperature rise in the Stated Policies Scenario by around 0.1 °C in 2050.

Glossary

Oil and gas abatement technologies

A variety of technologies and measures are available to reduce methane emissions from oil and gas operations. The options deployed vary by country, depending on the prevailing emissions sources, gas prices and capital and labour costs. For the purposes of the marginal abatement cost curve, we have grouped the different abatement technologies into the following categories:

Replace existing devices

Many pieces of equipment in the oil and natural gas value chains emit natural gas in their regular course of operation, including valves, and gas-driven pneumatic controllers and pumps. Retrofitting these devices or replacing them with lower-emitting versions can reduce emissions.

Replace pumps. Pneumatic pumps that use pressurised natural gas as a power source also vent natural gas in the ordinary course of their operation. These emissions can be eliminated through replacement with electrical pumps powered by solar or other generators, or connected to the grid.

Replace with electric motor. Gas-driven pneumatic devices continuously release small amounts of gas, even when specified as "low-bleed." These devices can be replaced with "zero-bleed" technologies that use electrical power to operate, instead of pressurised natural gas. An electric motor can also replace a diesel or gas engine used onsite during drilling and well completion.

Replace compressor seal or rod. Different kinds of compressors are used across the oil and natural gas supply chains to move product through the system, and the methane abatement cost curve includes several activities that reduce the possibilities for gas to escape.

Replace with instrument air systems. Pumps and controllers that vent natural gas by design can be replaced with instrument air systems that pressurise ambient air to perform the same functions without emitting methane.

Installing new devices

Many opportunities exist across the supply chain to install devices that can reduce or avoid large sources of vented emissions:

Vapour Recovery Units (VRUs). VRUs are small compressors designed to capture emissions that build up in pieces of equipment across the oil and natural gas supply chains. For instance, VRUs can capture gases that accumulate in oil storage tanks and that are otherwise periodically vented to the atmosphere to prevent explosion.

Blowdown capture. Gas blowdowns are conducted at wellheads or elsewhere along the supply chain when equipment (e.g. vessels, compressors) must be depressurised. Blowdowns can be triggered by emergency signals or routine start up or shut down procedures. When this happens, operators open the well to remove the liquids and gas. Emissions are mitigated when excess gas is recovered and used onsite or sent to the sales line, instead of being vented or flared.

Improve flaring. While still a source of CO_2 and methane emissions, flaring is preferable to direct release of the methane gas to the atmosphere. Combustion efficiencies at flares can decline as a result of lower production rates, environmental conditions and poor maintenance. Flaring can be improved using automated air-fuel ratio controls and electronic ignition devices. Vents from tanks, dehydrators and other equipment can be routed to flares while portable flares can help reduce emissions from non-routine activities such as well workovers or completions.

Install plunger. Periodically over the life of a producing well, downhole liquids need to be removed to facilitate continued flow of product (often called "liquid unloading"). Traditionally, a well operator opens the well and vents methane, relieving pressure and drawing liquids up through the wellbore. Plunger lifts may be installed to extract liquids more efficiently, while limiting the escape of methane. As pressure from accumulating fluids builds up, it pushes on the plunger. The plunger draws up gas and liquids in its wake. If a certain threshold of reservoir pressure is achieved through withdrawal of the plunger, gas can go directly to the sales line with no venting.

Associated gas utilisation. There are various technologies available to enable the utilization or commercialisation of small volumes of associated natural gas, including microturbines, mini-CNG, mini-GTL (gas to liquids), or mini-LNG facilities. Micro-technologies can offer capacity for compression or liquefaction of associated gas in remote locations. These technologies avoid venting and flaring by capturing gas for use at the facility, in the surrounding community, or for transport by truck or rail.

Leak detection and repair (LDAR)

Leak detection and repair (LDAR) refers to the process of locating and repairing fugitive leaks. LDAR encompasses several techniques and equipment types. One common approach is the use of infrared cameras, which make methane leaks visible. LDAR can be applied across the supply chain, to both upstream activities (including well development, gathering, processing) and/or downstream activities (such as transmission or distribution lines).

In the cost curve, we include varying frequencies of these programmes, from annual to quarterly. We also consider the option of a continuous monitoring system, either based on remote or facility-based sensors (Daily LDAR), which abates emissions from large leaks that occur sporadically such as those detected by satellites.

The cost of inspection differs depending on the value chain segment in question. LDAR programmes tend to be more cost-effective for upstream operations since it takes longer to inspect compressors on transmission pipelines, relative to those concentrated at a production facility.

Other

IEA analysis includes alternative and innovative technologies and techniques in addition to the categories above as well as measures to address emissions from abandoned wells.

Monitor and plug abandoned wells. Wells that were not appropriately decommissioned, or that have vents, can continue emitting methane for many years. Monitoring these sites allows the identification of wells with significant levels of emissions, which can then be plugged and remediated.

Other. This label includes approaches such as: installing methane-reducing catalysts; conducting a pipeline pump-down before maintenance; and reduced-emission or "green" completions.

Coal mine methane abatement technologies

There are significant opportunities to reduce emissions from the coal sector based on existing technologies. Abatement technologies are grouped into six types of abatement measures, two for each main emissions source: degasification systems (drained CMM utilisation, flare); ventilation systems (VAM oxidation, on-site recovery and use); and other CMM sources (capture and route to abatement; efficiency improvements). Mitigation measures vary by mine type, the specific source of emissions, CMM concentrations, and absolute emissions volumes.

Degasification systems

Higher-concentration sources of methane can be captured if measures are planned prior to the start-up of mining operations. Degasification wells and drainage boreholes can capture methane in coal reservoirs (coal seams or strata), reducing the potential of leaks during production. These systems can also be applied to working mines before operations move to new areas of coal exploration or after operations have ceased in an area. While underground mines hold the greatest potential for abatement through these systems, degasification programs have also been successfully applied to surface mines (see, for example, the case of North Antelope Rochelle Mine).

The quality of post-drained gas must be maintained sufficiently high for safe utilisation. This is achieved through design, monitoring and suction control. If gas is captured, it can either be used or flared, depending on the concentration of methane, mine characteristics and the local context.

Flare. When the amount of drained gas is limited and there are no feasible alternatives to use its energy content, flares can combust methane to reduce its climate impact. Flare systems include open flares and enclosed combustion systems. This abatement measure is assigned to degasification systems of mines with annual emissions below 1 kt CH_4. Flares are also used to handle the variability of methane flows in CMM utilisation projects. In this sense, this measure is also assigned to 10% of emissions from degasification systems in mines with drained CMM utilisation.

Drained CMM utilisation includes several technologies that could be used at mines with total emissions above the threshold established for flaring. This includes:

- Degasification for power generation - Drained methane can be used for on-site power generation provided there is sufficient and continuous gas flow. This can help meet the mine’s electricity requirements (e.g. powering mining machines, conveyor belts, ventilation systems) and, when in excess, be sold to the local power grid.

- Degasification for pipeline injection - If methane concentrations are high enough and there are nearby markets and transport infrastructure for natural gas, the captured methane can be directed to pipelines. Often this will require a processing stage to ensure the gas meets pipeline requirements.

- On-site use in coal drying or mine boiler - Captured methane can be used as a heat source either in boilers (for in-mine heating) or coal drying systems. This allows mines to use less coal for these activities.

- Combined heat and power generation - Many CMM abatement projects direct captured methane to systems that produce both electricity and heat. These often provide an optimal solution since they serve the two main energy needs of coal operations and provide greater flexibility.

- Alternative and innovative technologies - These include using captured methane for manufacturing feedstock, mini liquefied natural gas (LNG) or mini compressed natural gas (CNG) systems. These can be an alternative for mines that expect to capture gas with a high methane content for a limited amount of time or that face challenges to implement other mitigation options.

The choice of the abatement technology depends on local characteristics, such as the availability of nearby pipelines, heating demand and methane concentrations. For modelling purposes, we use power generation as the reference option, as this is the most common drained CMM utilisation measure to date. The costs associated with this option include spending for the installation and maintenance of the degasification system as well as gas-fired generators and a grid connection. Gas capture is often carried out to facilitate a required production rate of coal, safely within legally allowed methane concentrations. Mitigation costs include work done to improve gas capture beyond that which is necessary for mine safety, such as directional horizontal wells targeting coal seams.

Ventilation systems

Underground coal mines use ventilation systems to move fresh air into the mine, dilute methane released into the mine workings as coal is extracted and maintain safe working conditions. Methane concentrations are kept low inside mines to avoid explosion risks. As a result, ventilation air exhausts contain very low concentrations of methane (typically less than 1%). However, since these are generally large-scale systems with high flow rates, they are the largest source of CMM emissions.

Ventilation air methane can be directed to processes such as blending or oxidation to make it usable as an energy source or destroy it.

Ventilation air methane oxidation. Thermal or catalytic oxidation technologies are technically feasible at low methane concentrations (between 0.25% and 1.25%) and enable the destruction of VAM to reduce its climate impact. This is the abatement measure assigned to ventilation systems of mines with a methane intensity below 10 kgCH_4/t of coal or total annual CMM emissions below 10 kt.

On-site recovery and use is the abatement measure assigned to ventilation systems of mines with methane intensities and total emissions above the thresholds established for VAM oxidation. Where methane concentrations are high enough and operational characteristics suitable, oxidation technologies allow for heat recovery. This recovered heat can support shaft heating during winter or coal drying systems. VAM can also be used a supplemental fuel, serving as combustion air for engines, turbines and boilers (see the US EPA's Ventilation Air Methane Utilization Technologies).

Other CMM sources

Both surface and underground mines have additional CMM sources not covered in the above groups. These include methane from post-mining activities, outcrops and workings, and losses of methane resulting of incomplete combustion or leaks from gas infrastructure or equipment.

Efficiency improvements are the main option to reduce methane slips from incomplete combustion at flares, improve oxidation rates at VAM oxidation units and minimise losses from gas engines and related equipment. These include measures to monitor abatement processes (e.g. flaring destruction efficiency), automate air-fuel ratio controls, manage gas flows and operating temperatures as well as reduce upset conditions (e.g. unlit flares).

Capture and route are the main options for addressing fugitive emissions from coal mines. These form the bulk of surface mine emissions and are also relevant for underground mines. They include emissions from outcrops, fractured ground above workings and unsealed mine entries. Fugitive sources also include unintentional emissions from gas infrastructure of methane projects installed on a mine.

Capture and route measures avoid methane emissions by monitoring potential sources of emissions, capturing or sealing fugitive sources (e.g. closing unused mine entries or boreholes), and directing them to drainage or VAM abatement systems. They include supplementary equipment maintenance and planning to avoid equipment downtime and unnecessary methane venting related to routine operations.

Policy options

Different types of regulatory measures can be applied to methane. For each abatement technology described above, we have assigned a specific policy measure that targets this technology. Thus, for the purposes of our estimates of mitigation potential in the marginal abatement cost curve, we have grouped the different abatement actions into the following policy options:

Tried and tested policies

Certain policies have well-established precedents, as they have already been applied in multiple settings. These measures have proven to be both effective and relatively straightforward to administer. Policies in this category have the added benefit of not requiring very advanced tools to verify compliance, although some basic quantification and reporting mechanism is generally necessary. The measures in this category also tend to fall on the lower end of the abatement cost curve – and tend therefore to be the most cost-effective overall.

Leak detection and repair (LDAR). This refers to policies that require companies to establish programs for locating and repairing fugitive leaks. These policies often specify the method and equipment required for leak detection, the frequency of detection campaigns, which facilities must undertake the inspections, and a requirement to fix leaks within a certain timeframe. Within the IEA methane emissions model, this corresponds to both upstream and downstream abatement options. The model assumes that leak detection and repair will apply to all facilities and may be applied at different frequencies. In the policy marginal abatement cost curve, this includes inspection requirements that are at least quarterly, as this frequency is common among current requirements.

Technology standards. This refers to policies that set specific guidelines for equipment, technologies or procedures. Generally, such requirements mandate that certain equipment be replaced by a lower-emitting alternative. Within the methane model, this corresponds to the following abatement options: replace compressor seal or rod; early replacement of devices; replace with instrument air systems; and replace pumps.

Zero non-emergency flaring and venting. This refers to policies that either prohibit all non-emergency flaring and venting or those that mandate specific processes and procedures which result in less flaring and venting. Within the methane model, this corresponds to the following abatement options: install plunger; improve flaring; blowdown capture; and vapour recovery units.

Additional measures

Robust measurement-based monitoring regimes combined with additional regulations can encourage additional abatement. Within the IEA methane emissions model, additional measures correspond to the following abatement options: replace with electric motor; continuous leak detection and repair; daily leak detection and repair; monitor and plug abandoned wells; other. These actions can be driven by a combination of different policies, including enhanced technology standards, performance standards, emissions pricing, financing instruments, and monitoring, reporting and verification regimes. More information about these additional measures can be found in Curtailing Methane Emissions from Fossil Fuel Operations.

Policy explorer

The Global Methane Tracker now includes a detailed country-by-country breakdown of policies in place for certain countries. This tool is based on the IEA's Policies Database. The explorer tool categorises policies by type of policy (prescriptive, performance-based, economic, or information-based). Specific definitions used in the policy explorer tool are found below. Further details can be found in Driving Down Methane Leaks from the Oil and Gas Industry: A Regulatory Roadmap and Toolkit.

Prescriptive

Regulations that direct regulated entities to undertake or not to undertake specific actions or procedures. This command-and-control approach focuses on setting procedural, equipment or technological requirements such as the installation or replacement of specific devices.

Leak detection and repair. Requirements to implement fugitive emissions management plans that include the process of locating and repairing fugitive leaks. Policies may address the type of equipment used, frequency of inspection, the leak threshold that triggers repair requirements and the length of time allowed to conduct the repairs.

Flaring or venting restrictions. Regulations that limit the amount of flaring or venting allowed or that prescribe the equipment or process for flaring or venting. This includes limitations on total volume, banning of such activities in routine proceedings (allowed only for safety reasons or special conditions), the need to request authorisations beforehand, or specifications of equipment or procedures.

Technology standards. Requirements that outline the equipment, technology or procedure that must be employed in a regulated activity (e.g. requiring the use of no-bleed pneumatic devices; requiring both high- and low-pressure gas-liquid separation stages to minimise vapour released from produced hydrocarbon liquid; requiring collection of vented natural gas from the unloading of liquids). This includes best available technology requirements, which refer to a benchmark technology or procedure for reducing emissions that is considered reasonably practicable and evolves according to technological development.

Permitting requirements. Permits are a means of granting authorisation for specific operations or procedures (e.g. pollution permits, drilling permits). Permits also include conditions that limit their validity, which may be temporal, technological or spatial.

Performance

Regulations that establish a performance standard for regulated entities, but do not dictate how the target must be achieved. An absolute or relative performance target can be applied at the national level, through economy- or sector-wide targets; at the company level; at the level of each facility; or even to individual types of equipment.

Reduction targets. These refer to reduction goals, including the definition of baselines, intermediate goals and means of assessing progress, reviewing objectives and achieving established targets. At national level or sectoral level (e.g. 50% methane reductions in the oil and gas industry in 2030 from the 2010 baseline), these generally serve as a strategic instrument and do not impose specific requirements on companies.

Flaring or venting standards. Regulations that limit the amount of flaring or venting for the purpose of disposal allowed through a performance metric (e.g. minimum gas utilisation rates, admissible volume as a percentage of output) or establish other performance requirements (e.g. flaring must be designed for 98% efficiency). Regulations aimed primarily at fugitive emissions are not included in this category.

Process or equipment emissions standards. Regulations that limit emissions through a performance metric set at the process- or equipment-level (e.g. glycol dehydration units must control emissions by 95%). They generally cover different aspects related to atmospheric emissions, such as leak rates, discharge characteristics (e.g. temperature) or means (e.g. minimum height of discharge).

Facility or company emissions standards. Regulations that limit emissions through a performance metric set at the facility or company-level (e.g. each company must reduce emissions by 20% on a per unit basis). They generally cover different aspects related to atmospheric emissions, such as quantity (e.g. volume) or characteristics (e.g. concentration). This includes company or facility specific limits and associated reduction plans.

Economic

Regulations that use economic provisions to induce action by applying financial penalties or incentives. This may include taxes, subsidies or market-based instruments, such as tradeable emissions permits or credits, that allow firms to choose among different strategies to address emissions (e.g. directly reduce emissions or pay for offsets), effectively changing the cost curve of abatement.

Taxes or charges on emissions. Taxes, fees or other charges that are levied on emissions, including nationwide carbon taxes applied to methane or royalties and other charges imposed on fugitive emissions and methane emitted as result of operation of equipment or certain processes (e.g. emissions from high- or intermittent-bleed pneumatic devices).

Taxes or charges on gas disposal (flaring or venting). This refers to taxes, fees and charges that are levied when operators dispose of excess gas by flaring or venting.

Grants or other financial incentives. This includes all types of positive financial incentives that governments provide to reduce emissions. This could include direct provision of loans or grants to invest in reduction measures or other incentives such as allowing cost recovery for abatement costs via reductions in royalties, taxes or fees.

Emissions trading schemes and certified reduction credits. Emissions trading schemes typically define an emissions limit and allocate emissions allowances among the regulated community. These allowances can then be traded among companies according to their needs and capabilities. Certified reduction credits allow entities that go beyond established requirements to be accredited as voluntary methane reductions, which may be traded. This item also includes any requirements that allow companies to achieve emissions reduction by buying tradable credits.

Information

Regulations that are designed to improve the state of information about emissions, and may include requirements that regulated entities estimate, measure and report their emissions to public bodies.

Measurement requirements. Mandatory data collection for activities, equipment or production flows (e.g. volume of gas flared or vented, fugitive emissions leak rates from compressors), requiring operators to record, process and submit requested information. They support the definition of activity or emission factors that are specific to measured devices, facilities and settings.

Reporting requirements. Regulated entities must record and report required information. This can include reporting emissions monitoring data, key events (e.g. accidents, flaring), state of facilities or operational data. Regulations can indicate if information must be disclosed to the public or sent to regulatory authorities.

Emissions estimates and quantification. Requirements to estimate methane emissions through activity and emission factors.

Public disclosure. Requirements for regulated entities to share specified information related to methane emissions with the public (e.g. requirements to publish methane emission reports online, to undertake public information campaigns, or to disclose information upon public request). This also includes instruments that require public bodies to make specified information received from regulated entities available to the public.

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