Emissions from Oil and Gas Operations in Net Zero Transitions

A World Energy Outlook Special Report on the Oil and Gas Industry and COP28

International Energy Agency

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Abstract

Today, oil and gas operations account for around 15% of total energy-related emissions globally, the equivalent of 5.1 billion tonnes of greenhouse gas emissions. In the International Energy Agency's Net Zero Emissions by 2050 Scenario, the emissions intensity of these activities falls by 50% by the end of the decade. Combined with the reductions in oil and gas consumption in this scenario, this results in a 60% reduction in emissions from oil and gas operations to 2030.

Fortunately, oil and gas producers have a clear opportunity to address the problem of emissions from their activities through a series of ready-to-implement and cost-effective measures. These include tackling methane emissions, eliminating all non-emergency flaring, electrifying upstream facilities with low-emissions electricity, equipping oil and gas processes with carbon capture, utilisation and storage technologies, and expanding the use of hydrogen from low-emissions electrolysis in refineries.

Upfront investments totalling USD 600 billion would be required to halve the emissions intensity of oil and gas operations globally by 2030. This is only a fraction of the record windfall income that oil and gas producers accrued in 2022 – a year of soaring energy prices amid a global energy crisis. This report aims to inform discussions on these issues in the run-up to the COP28 Climate Change Conference in Dubai in November and is part of a broader World Energy Outlook special report to be released later in 2023 focusing on the role of the oil and gas industry in net zero transitions.

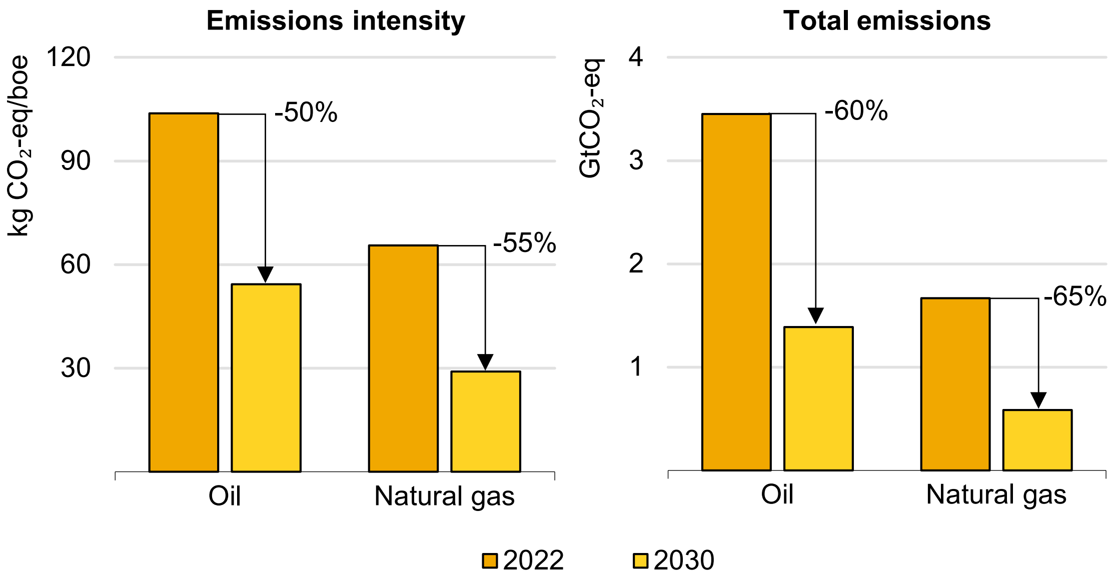
Executive summary

The production, transport and processing of oil and gas resulted in 5.1 billion tonnes (Gt) CO_2-eq in 2022. These "scope 1 and 2" emissions from oil and gas activities are responsible for just under 15% of total energy-related greenhouse gas (GHG) emissions. The use of the oil and gas results in another 40% of emissions.

In this report, we look at the changes and measures needed to reduce the emissions intensity of oil and gas operations in the IEA's Net Zero Emissions by 2050 (NZE) Scenario. The work brings together, expands and updates analysis from previous IEA work to inform discussions in the run up to COP28 in Dubai. It is part of a broader World Energy Outlook Special Report to be released in 2023 focussing on the role of the oil and gas industry in net zero transitions.

The NZE Scenario maps out a way to limit the global average temperature rise to 1.5°C alongside achieving universal access to modern energy by 2030. This scenario sees a rapid decline in oil and gas demand, which is sufficiently steep that it can be satisfied in aggregate without developing new oil and gas fields. There is also an immediate, concerted effort by all the oil and gas industry to limit emissions from its activities. In the NZE Scenario, the global average emissions intensity of oil and gas supply falls by more than 50% between 2022 and 2030. Combined with the reductions in oil and gas consumption, this results in a 60% reduction in emissions from oil and gas operations to 2030.

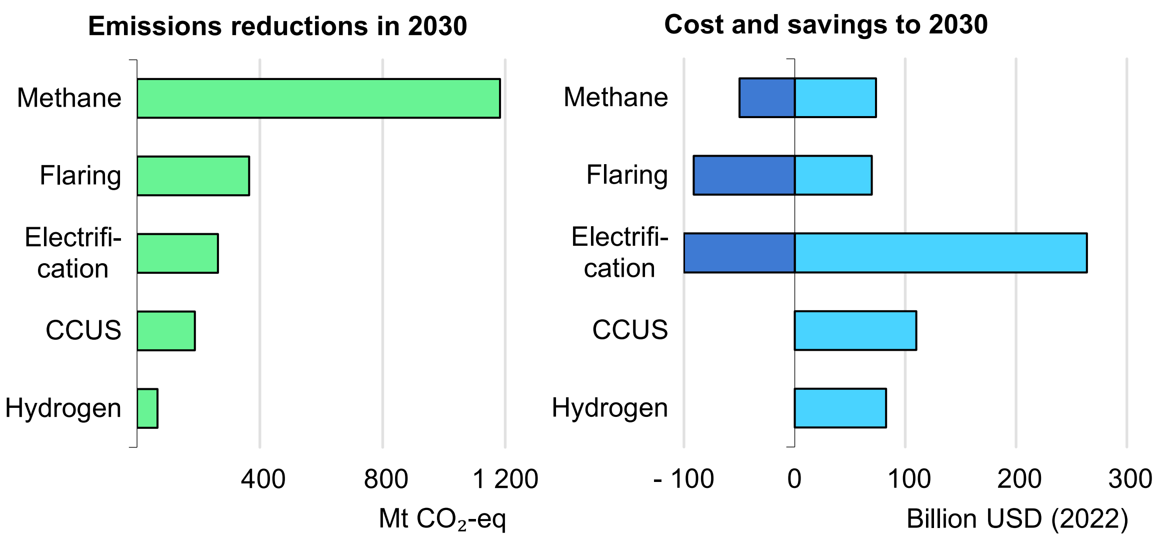
Scope 1 and 2 emissions intensities of oil and gas operations in the NZE Scenario and total emissions from operations in 2022 and 2030



Five key levers are used to achieve this reduction in emissions intensities: tackling methane emissions, eliminating all non-emergency flaring, electrifying upstream facilities with low-emissions electricity, equipping oil and gas processes with carbon capture utilisation and storage (CCUS), and expanding the use of low-emissions electrolysis hydrogen in refineries. No offsets are used to achieve the reductions in emissions in the NZE Scenario.

Tackling methane emissions is the single most important measure that contributes to the overall fall in emissions from oil and gas operations, followed by eliminating flaring and electrification. Scaling up CCUS and expanding the use of low-emissions hydrogen play complementary roles but have significant potential for positive spillovers into other aspects of energy transitions, by accelerating deployment and technology learning for these technologies.

Reductions in emissions from oil and gas operations in 2030 in the NZE Scenario and cumulative cost and savings of deploying these measures from 2022 to 2030



Tackling scope 1 and 2 emissions from oil and gas is one of the most viable and lowest cost options to reduce total GHG emissions from any activity to 2030. Around USD 600 billion upfront spending is required over the period to 2030 to achieve the full 50% reduction in the emissions intensity of oil and gas operations. This is 15% of the windfall net income the industry received in 2022. Many of the measures also lead to additional income streams by avoiding the use or waste of gas meaning they can quickly recoup the upfront spending required. For facilities implementing these measures, the average cost of producing oil and gas would increase by less than USD 2 per barrel of oil equivalent (boe).

A number of companies have to date announced targets to reduce their scope 1 and 2 emissions. These vary markedly in their scope and timelines for implementation. Only a fraction of these commitments matches the pace of decline seen in the NZE Scenario and most plan to use offsets to achieve their targets. Forward-leaning companies need to recognise the need to move faster than the global average reduction in emissions and build a broader coalition of companies willing to play their part.

To build public confidence in actions being taken, a consistent approach is needed to monitor, report, and verify emissions from oil and gas activities. This should be based on robust measurements to improve the accuracy, availability, and transparency of emissions data.

Introduction

The Net-Zero Emissions by 2050 Scenario (NZE) involves transformation of the global energy system that is unparalleled in its speed and scope. Policies are rapidly introduced to reduce emissions from existing fossil fuel infrastructure and to scale up the deployment of clean energy technologies. Clean energy investment therefore rises three-fold in the period to 2030 from USD 1.4 trillion in 2022 to more than USD 4 trillion in 2030. This investment surge leads to a decline in energy-related emissions and demand for fossil fuels.

The declines in oil and gas demand in the NZE Scenario are sufficiently steep that it is possible to meet them without the need for new long lead time upstream conventional projects. This brings down total upstream investments considerably compared with the levels seen in 2022. Nonetheless, continued investment in existing oil and gas assets is essential in the NZE Scenario. This is to ensure that oil and gas supply does not fall faster than the decline in demand and also to reduce the emissions arising from oil and gas operations.

This report sets out the current contribution of oil and gas activities to global greenhouse gas (GHG) emissions, the opportunity and costs of measures that can tackle these emissions, and the reductions seen in oil and gas "scope 1 and 2" emissions in the NZE Scenario in the period to 2030.[1]

This work builds on the modelling and approach to oil and gas emissions described in the World Energy Outlook (WEO) 2018, the WEO special report on The Oil and Gas Industry in Energy Transitions from 2020, and the latest version of the NZE Scenario published in the WEO 2022. Invaluable input to the analysis was provided by the Rocky Mountain Institute's (RMI) Oil Climate Index plus Gas (OCI+) and the World Bank Global Gas Flaring Reduction Partnership. Further details on definitions and the modelling approach can be found in the Technical Annex.

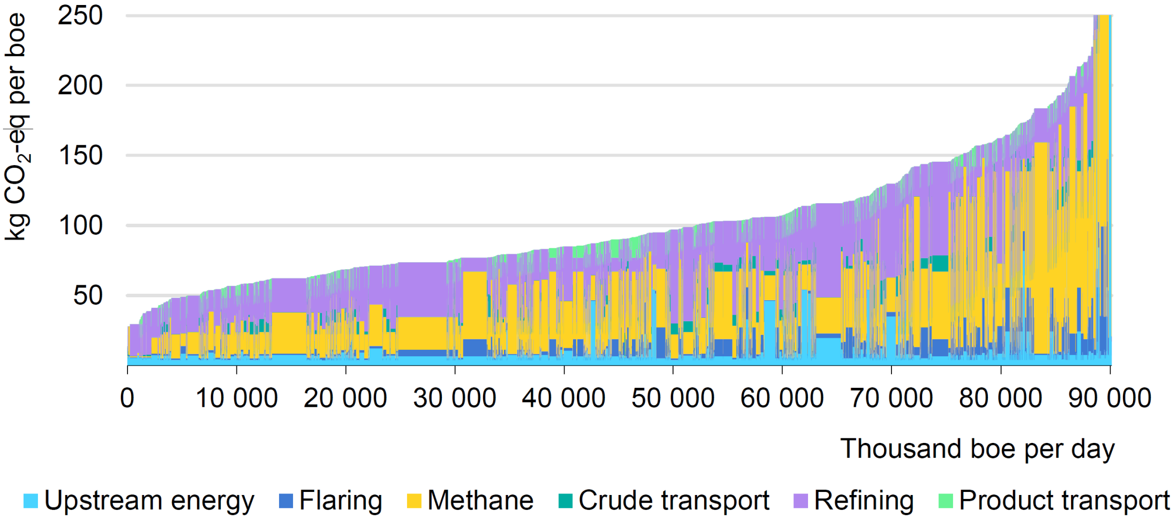
[1] In this report, "scope 1" emissions are taken as emissions that come directly from the oil and gas industry itself (e.g. emissions from powering the engines of drilling rigs or methane emissions that arise during oil and gas extraction or transport). "Scope 2" emissions arise from the generation of energy that is purchased by the oil and gas industry (e.g. from the generation of electricity taken from a centralised grid to power auxiliary services. The sum of scope 1 and 2 emissions is often referred to as the "well-to-tank" or "well-to-meter" emissions.

Emissions intensities today

Oil and gas operations today are responsible for 15% of global energy-related GHG emissions

According to latest IEA data and estimates, oil and gas operations resulted in 5.1 billion tonnes (Gt) CO_2-eq in 2022. Global energy-related GHG emissions were around 40 Gt CO_2-eq in 2022, meaning the oil and gas industry was directly responsible for nearly 15% of energy GHG emissions. Oil operations were responsible for 3.5 Gt CO_2-eq and natural gas operations for 1.6 Gt CO_2-eq.

Spectrum of scope 1 and 2 emissions intensities for oil, 2022



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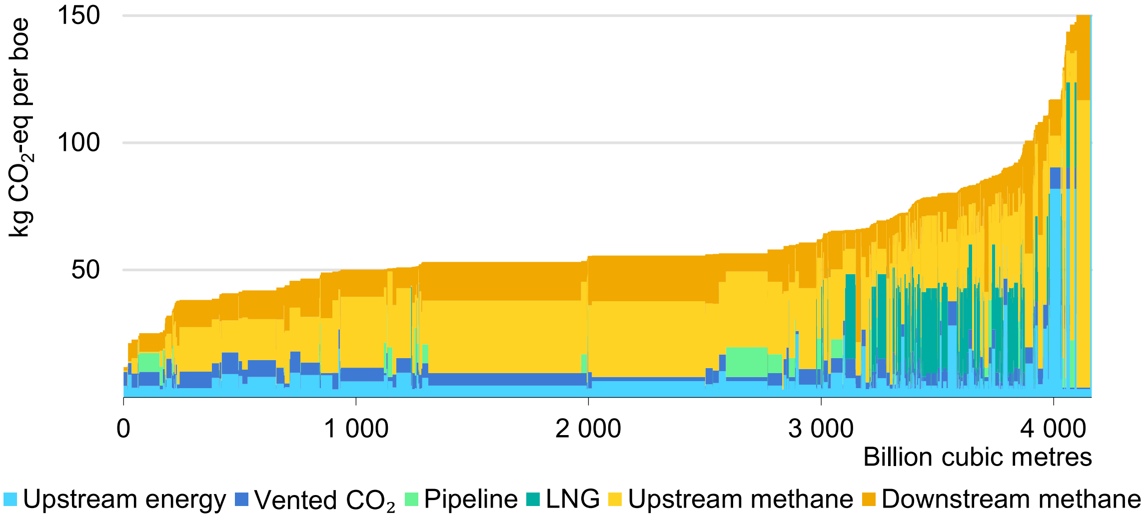
These emissions come from a variety of sources along the oil and gas supply chains. Extracting oil and gas from the subsurface requires large amounts of energy to power drilling rigs, pumps and other process equipment and to provide heat. Most oil is refined prior to use and this requires large quantities of energy, especially to produce the hydrogen that is used to upgrade and treat the crude oil. Natural gas also undergoes processing to separate natural gas liquids and remove impurities such as CO_2, hydrogen sulphide or sulphur dioxide. Crude oil, oil products and natural gas are transported, often over long distances, by both pipeline and by ship and these processes are also an important source of GHG emissions.

In 2022, the energy required for the extraction, processing, refining and transport of oil resulted in 450 Mt CO_2 emissions. Gas flaring, predominantly at oil production facilities, resulted in a further 250 Mt CO_2 emissions. The energy for natural gas extraction, processing and transport resulted in 270 Mt CO_2 emissions. In addition, we estimate that oil and gas operations resulted in the extraction of around 130 Mt of naturally occurring CO_2 that was vented to the atmosphere.

Natural gas is predominantly methane, a potent GHG, and there are multiple potential sources of fugitive and vented methane emissions along the oil and gas supply chains. We estimate that upstream oil operations resulted in [45 Mt of methane emissions in 2022](), upstream natural gas operations resulted in around 25 Mt and natural gas transport resulted in just over 10 Mt. In total, this is equivalent to 2.4 Gt CO_2-eq.[2]

Spectrum of scope 1 and 2 emissions intensities for natural gas, 2022



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Putting these figures together, 105 kg CO_2-eq is emitted on average for each barrel of oil produced: this is 20% of the full lifecycle emissions intensity of oil.[3] Scope 1 and 2 emissions from natural gas are 65 kg CO_2-eq per barrel of oil equivalent (boe) produced, 15% of the full lifecycle emissions of natural gas. There is a strikingly broad range of emissions for different types of oil and gas production: the highest 10% of production for oil, for example, results in around four-times more scope 1 and 2 emissions than the lowest 10%. For oil, emissions intensities

[2] One tonne of methane is considered to be equivalent to 30 tonnes CO_2 based on the 100-year global warming potential (IPCC, 2021).
[3] Different oil products result in different level of emissions when combusted but today's global average array of oil products produced from a barrel of oil equivalent (boe) results in 405 kg CO_2 when combusted. Natural gas combustion results in 320 kg CO_2 per boe (around 600 kg CO_2-eq per thousand cubic metres).

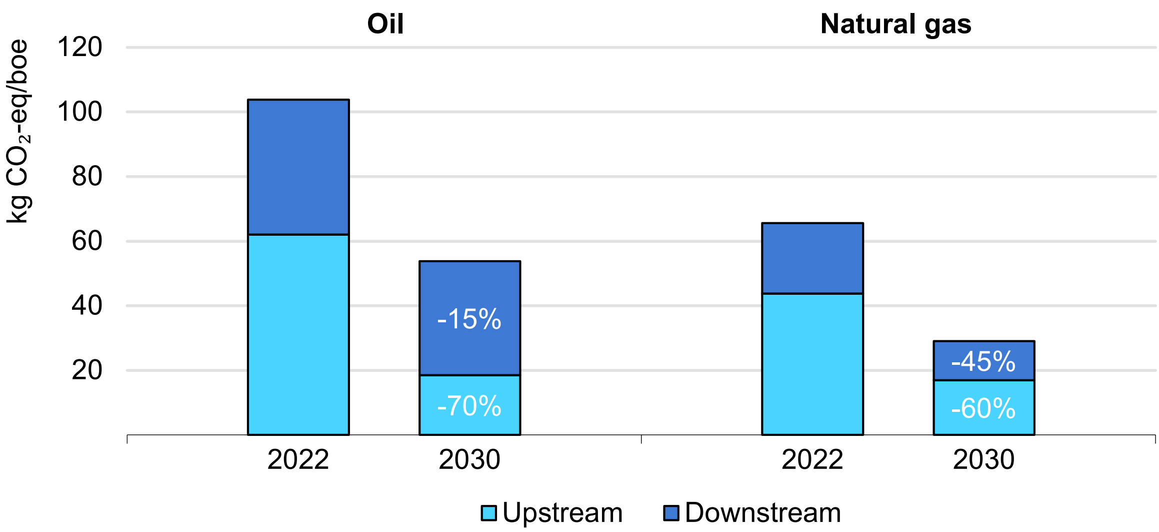
tend to be lower in places where the oil is easy to extract or where refining and consumption takes place close to the point of extraction. Intensities are also typically lower in locations that have low methane emissions or produce light oil or natural gas liquids (NGLs), which can be processed by simple refineries or bypass the refining sector entirely. For natural gas, the high energy intensity of transport means that countries that export a large share of their production as liquefied natural gas (LNG) or by long-distance pipeline tend to have a higher overall emissions intensity.

Reductions in the NZE Scenario

The emissions intensity of oil and gas supply falls by more than 50% to 2030, leading to a 60% overall reduction in emissions from oil and gas operations

In the NZE Scenario, a concerted effort by all oil and gas companies worldwide leads to a more than 50% reduction in the global average scope 1 and 2 emissions intensity between 2022 and 2030. Over this period, global oil and natural gas consumption both fall by around 20% to 2030. As a result, total scope 1 and 2 emissions from oil and gas operations fall by 60% between 2022 and 2030. The reductions in emissions are therefore much larger than those that would accrue simply by relying on reductions in demand to bring down emissions from oil and gas operations.

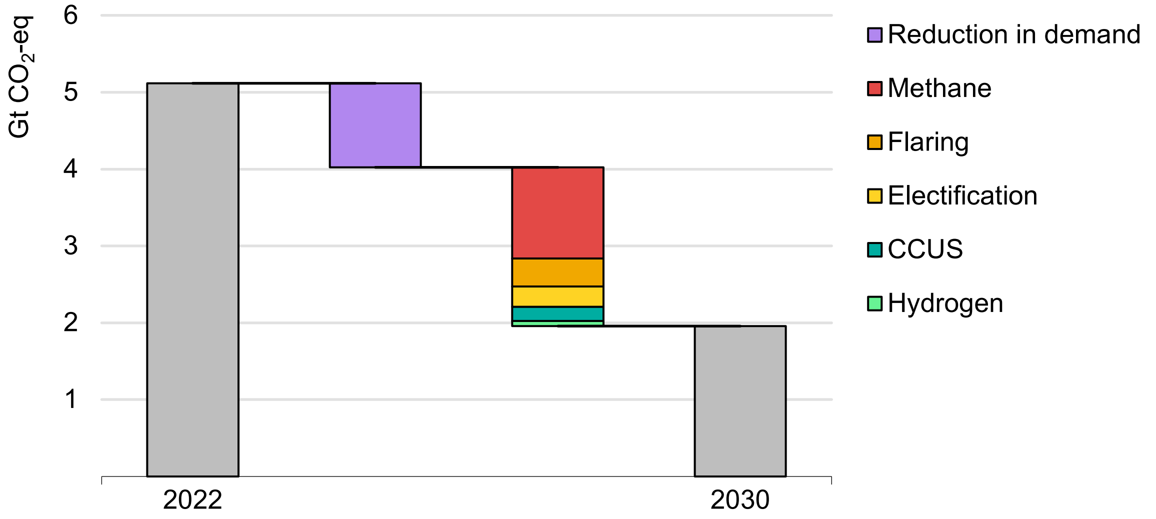
Summary of reductions in oil and gas emissions in the NZE Scenario to 2030



Five key levers are used to achieve this reduction in emissions intensities: tackling methane emissions, eliminating all non-emergency flaring, electrifying upstream facilities, equipping oil and gas processes with carbon capture utilisation and storage (CCUS), and expanding the use of low-emissions electrolysis hydrogen in refineries. No offsets are used to achieve the reductions in emissions in the NZE Scenario.

There are other options that could also help reduce scope 1 and 2 emissions from oil and gas activities. Transport emissions could be reduced by switching to low-emissions fuels in shipping, or emissions reduced through incremental improvements in the efficiency of upstream and downstream operations. We focus here on the key options that deliver the largest reductions in the period to 2030 and that are consistent with the goals of the NZE Scenario. These emissions reduction options are an integral part of the NZE Scenario but they should not be considered solely in this context: these are actions that can and should be taken in any future scenario for oil and gas demand.

Summary of reductions in total oil and gas emissions in the NZE Scenario by abatement measure to 2030



Notes: CCUS = carbon capture, utilisation and storage applied to hydrogen production at refineries or to supply refineries. Hydrogen is the use of low-emissions electrolysis hydrogen to replace hydrogen from unabated fossil fuels.

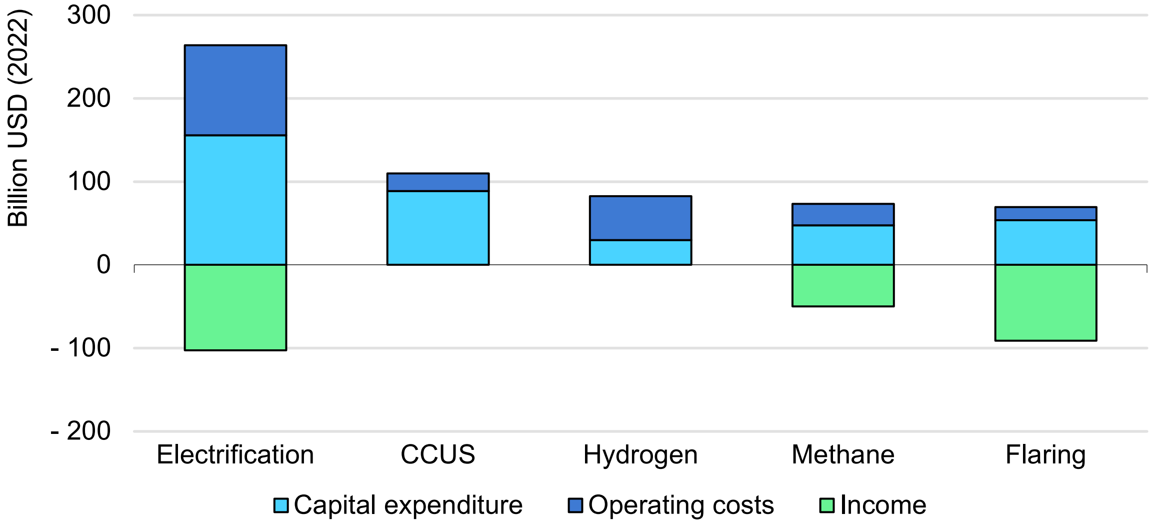
In the NZE Scenario, there is a 60% reduction in the global average upstream emissions intensity and a 20% reduction in the global average downstream emissions intensity to 2030. There are fewer immediately implementable options to reduce emissions in downstream activities, but action in these sectors to 2030 are crucial to help drive continued reductions in the emissions intensity of oil and gas operations after 2030.

Methane emissions account for a much larger share of overall scope 1 and 2 emissions for natural gas than for oil. Efforts to cut down on methane emissions in the NZE Scenario mean that the drop in the emissions intensity of natural gas (55% to 2030) is therefore slightly larger than for oil (50%).

A number of companies, accounting for just under half of global oil and gas production today, have announced plans or targets to reduce their scope 1 and 2 emissions. There is a need to build a much broader coalition of companies looking to achieve meaningful reductions in emissions with forward-leaning companies moving faster and achieving greater reductions than the global average pace of decline in the NZE Scenario.

We have assessed the cumulative level of spending that is required to implement these measures between 2022 and 2030. In total we estimate that USD 600 billion upfront spending is required, of which 65% is capital expenditure and 35% is operating costs. This is based on a granular assessment of actions across the five areas taking into account variations in technology costs across regions and spatial aspects, e.g. for electrification and flaring reduction. Total spending represents 15% of the net income generated by the oil and gas industry in 2022.

Cumulative capital and operating costs and savings from 2022 to 2030 in the NZE Scenario by measure



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Measures targeting methane emissions, flaring and electrification of operations avoid natural gas use on site or capture gas that would otherwise be lost. This can often be sold to generate an additional revenue stream and so many of the abatement options can end up paying for themselves. Nonetheless, even without these additional revenue streams, cutting methane emissions from oil and gas operations and stopping all non-emergency flaring are among the most readily-implementable and cost-effective measures available in any sector of the economy to reduce GHG emissions.

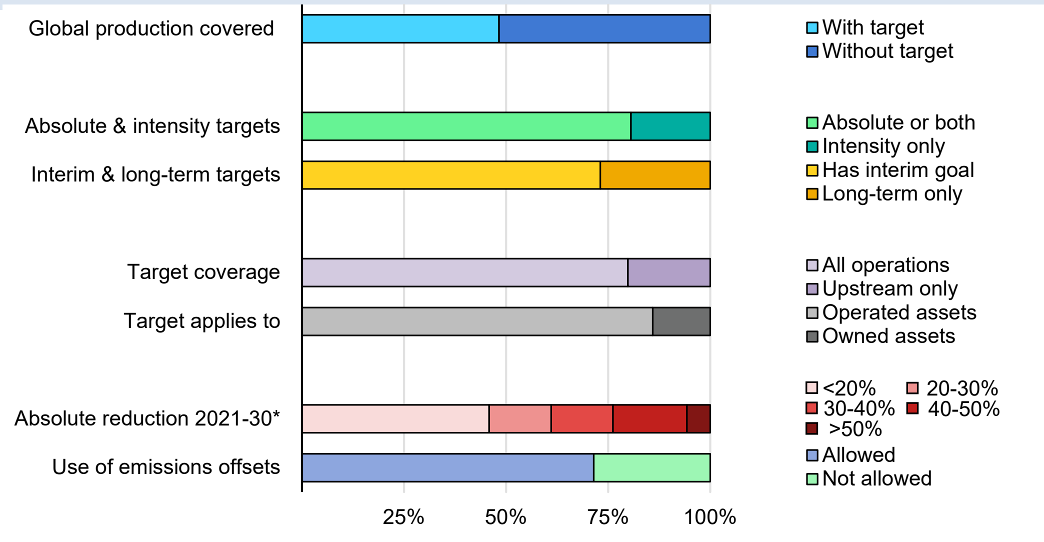
For long-lived projects, the spending to 2030 will continue to yield emissions reductions for many years after 2030. As oil and gas demand continues to decline in the NZE Scenario after 2030, operators may also be able to sell low emissions electricity or hydrogen to other users to generate additional revenue streams. In addition, reducing emissions through CCUS and the use of low-emissions hydrogen helps to stimulate learning and cost reductions in these technologies that are important for emissions reductions across the wider energy economy.

Action to reduce emissions from oil and gas operations is one of the most cost-effective ways to reduce global GHG emissions. We estimate that achieving the reductions in scope 1 and 2 emissions to 2030 in the NZE Scenario would add less than USD 2/boe on average to the cost of producing oil and gas at facilities implementing these measures (equivalent to around USD 0.3 per million British thermal units [MBtu]).

Company scope 1 and 2 emission reduction targets to date

Based on an analysis of the 40 largest oil and gas companies, we estimate that just under half of global oil and gas production is now produced by companies that have announced a target to reduce their scope 1 and 2 emissions. These vary widely in their nature, scope and ambition.

Coverage and characteristics of company scope 1 and 2 emissions targets



*Intensity reduction targets are converted to absolute reductions assuming stated production plans or production growth in line with historic trends. Linear interpolation is used to derive a value for 2030 when not given.
Source: IEA analysis based on annual reports of 40 oil and gas companies representing two thirds of global production, other companies are assumed not to have a target.

Most targets are for an absolute reduction in scope 1 and 2 emissions, expressed either as a percentage reduction over time or for emissions from operations to be below a specific level by a given date. Some targets are instead for a reduction in the emissions intensity of operations, expressed as a percentage reduction or to fall below a specific level (usually expressed in kg CO_2-eq/boe). Most companies have announced long-term targets with one or more interim targets; companies making up one quarter of global oil and gas production have announced a target only for 2050. Most companies also indicate that their reduction targets cover only directly-operated assets, rather than covering production from any asset in which they hold an equity stake. Finally, mergers and acquisitions will impact the progress of companies towards their targets. A number of principles have been proposed to limit the risk that asset sales from a company with a target to a company without a target could lead to an increase in global emissions.

We have converted all targets into a percentage reduction in absolute emissions to 2030 and find that companies accounting for less than 5% of oil and gas production have targets that would meet or exceed the 60% reduction in absolute scope 1 and 2 emissions in the NZE Scenario to 2030. Most companies also indicate that they intend to use emissions offsets to achieve their targets (the reductions in the NZE Scenario do not rely on any use of offsets).

Emissions reductions by measure

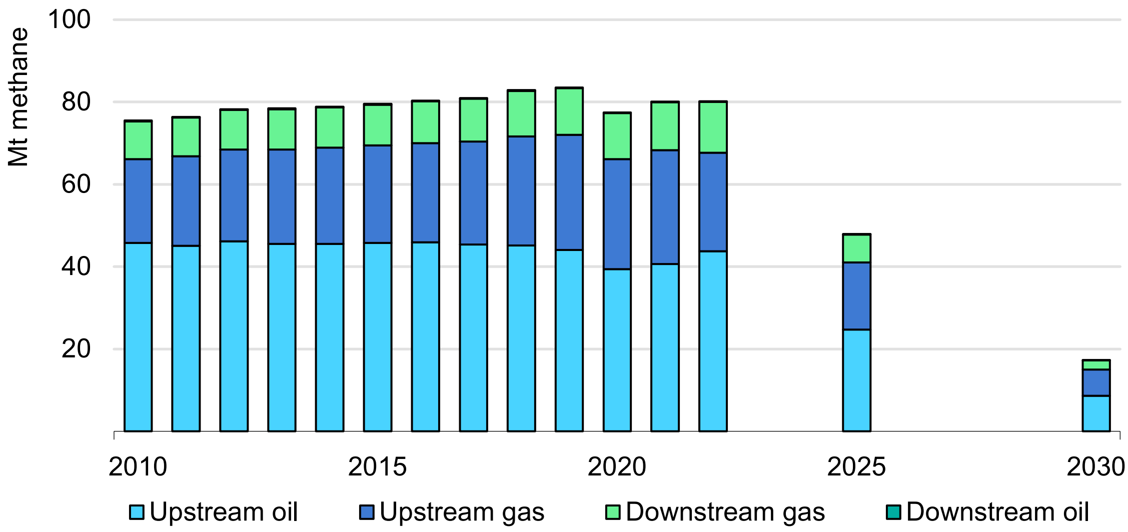
Minimise methane emissions

Cutting oil and gas methane by 75% is one of the most impactful measures to reduce GHG emissions to 2030

Methane is responsible for around 30% of the rise in global temperatures since the Industrial Revolution, and rapid and sustained reductions in methane emissions are key to limiting near-term warming and improving air quality. We estimate that the oil and gas industry is responsible for 80 Mt of methane emissions, equivalent to 2.4 Gt CO_2-eq. There is a wide variety of well-known technologies and measures available to reduce methane emissions from operations, and in the NZE Scenario emissions fall by over 60 Mt – a 75% reduction – to 2030.

One-third of this drop occurs because of reductions in oil and gas use to 2030 in the NZE Scenario, with the remaining two-thirds stemming from widespread efforts across all parts of the supply chain to reduce the emissions intensity of oil and gas operations (the methane emissions intensity of oil and gas production falls by more than 70% to 2030). By 2030, all oil and gas producers have an emissions intensity similar to the world's best operators today.

Oil and gas methane emissions in the NZE Scenario, 2010-2030

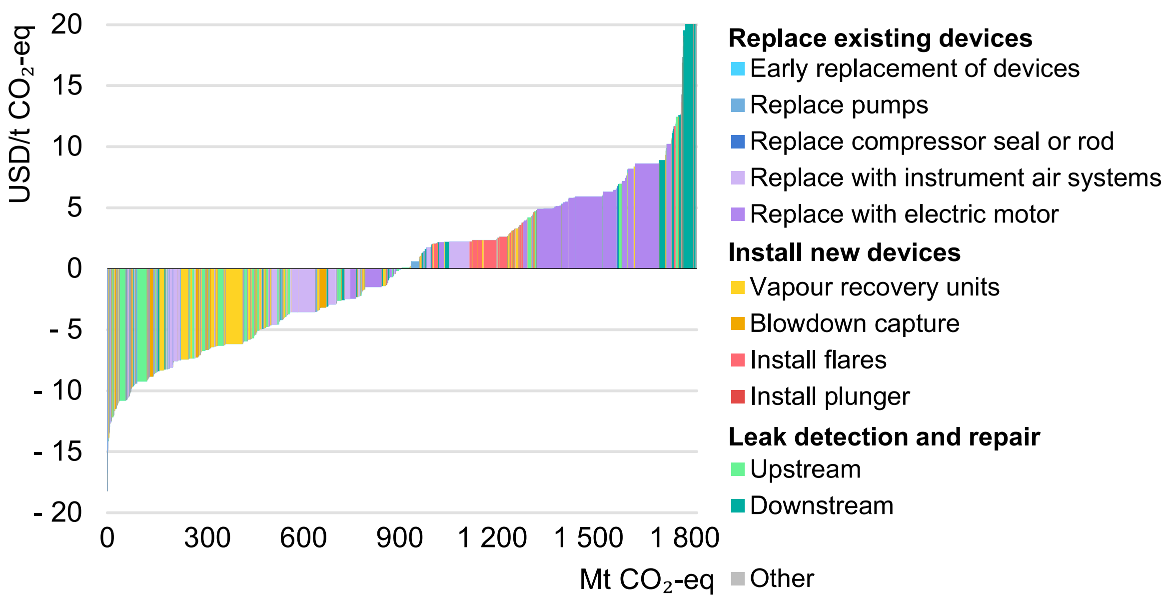


Technologies and measures to prevent methane emissions from oil and gas operations are well known and have already been deployed in multiple locations around the world. Key examples include leak detection and repair campaigns, installing emissions control devices, and replacing components that emit methane by design. Almost all available abatement measures cost less than USD 20/t CO_2-eq to deploy – and most would cost considerably less – meaning that mitigating methane emissions is amongst the lowest cost option of any technology that can bring about a step-change in global GHG emissions.

We estimate that USD 75 billion upfront spending is required between 2022 and 2030 to achieve the emissions reductions in the NZE Scenario. Around 65% of this is capital expenditure on new equipment and 35% is operating costs, mainly related to regular leak detection and repair programmes.[4]

Many measures can save money because the outlays required to deploy them are less than the market value of the methane that is captured and can be sold. Natural gas prices fall to low levels in the NZE Scenario but this additional income means that achieving a 75% reduction in emissions by 2030 would on average add just USD 0.05/boe to the cost of producing oil and gas in the NZE Scenario.

Costs from avoiding methane emissions at oil and gas operations, 2022



Note: Income from gas sales based on 2017-2021 average gas prices.

[4] The IEA will be releasing a second short report designed to inform discussions in the run-up to COP28 focusing on investment in reducing methane emissions and how this can be financed.

An immediate and significant change in the pace and scale of policy and industry action is needed to achieve the methane reductions in the NZE Scenario. As part of the Global Methane Pledge, 150 countries have committed to work together to collectively reduce methane emissions by at least 30% below 2020 levels by 2030. The most cost-effective opportunities for methane abatement are in the energy sector and the oil and gas sector should lead the way in efforts to achieve the Pledge. Industry efforts can and should also be enhanced with companies adopting a zero-tolerance approach to emissions from all assets in which they hold an equity stake and actively pushing for others to do similarly. Investors and financial actors can play an important role by taking the level of methane emissions into account when making financing decisions on oil and gas.

Greater transparency, through satellite detection, better industry standards and other monitoring tools, will greatly accelerate these efforts. Several countries have signed a Joint Declaration that calls for global action to support robust measurement and transparency of emissions data to help achieve rapid and sustained emissions reductions, and the US Inflation Reduction Act requires companies to report their emissions based on empirical and accurate data. The International Methane Emissions Observatory has been tasked to develop a comprehensive public dataset detailing methane emissions levels and sources from fossil fuel activities around the world.

Eliminate all non-emergency flaring

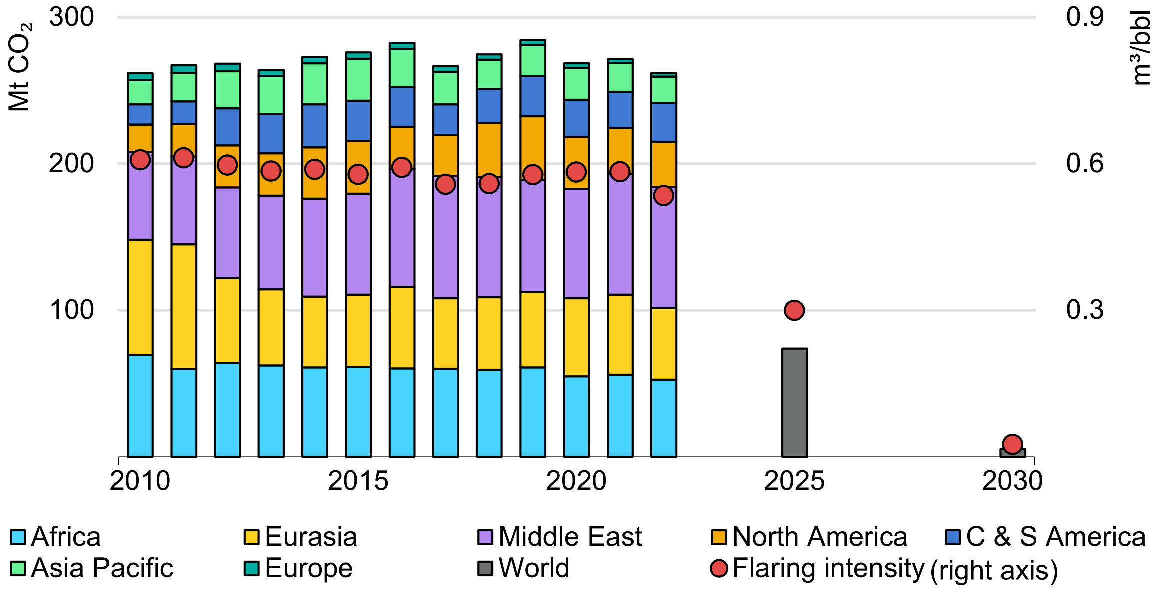
Natural gas flaring – totalling nearly 140 bcm in 2022 – is cut by 95% by 2030 in the NZE Scenario

Around 140 bcm natural gas was flared in 2022 causing 260 Mt CO_2 emissions – from the combustion of methane and natural gas liquids – and 8 Mt of methane emissions.[5] Flaring therefore resulted in 500 Mt CO_2-eq annual GHG emissions in 2022. Around 70% of gas flared goes to flares that operate on a near continual basis. In the NZE Scenario, all non-emergency flaring is eliminated globally by 2030, resulting in a 95% reduction in flared volumes and avoiding 365 Mt CO_2-eq.

There are many options to use natural gas that is currently flared, including by bringing it to consumers via a new or existing gas network, reinjecting it to support reservoir pressure, and converting it to compressed natural gas (CNG) or LNG. The gas can also be used to generate power, which needs to be equipped with CCUS if it is to substantially reduce the industry's scope 1 and 2 emissions.

[5] There should be minimal methane emissions if a flare is designed, maintained and operated correctly but this is not always the case. There are also occasions when flares are extinguished, resulting in direct venting to the atmosphere of gas that should be combusted. We estimate that around 92% of gas volumes directed into flares globally is properly combusted (in line with studies for the main oil and gas producing regions of the United States indicating a combustion rate of 90-92%).

CO_2 combustion emissions from flaring and flaring intensity in the NZE Scenario, 2010-2030



Notes: C & S America = Central and South America.

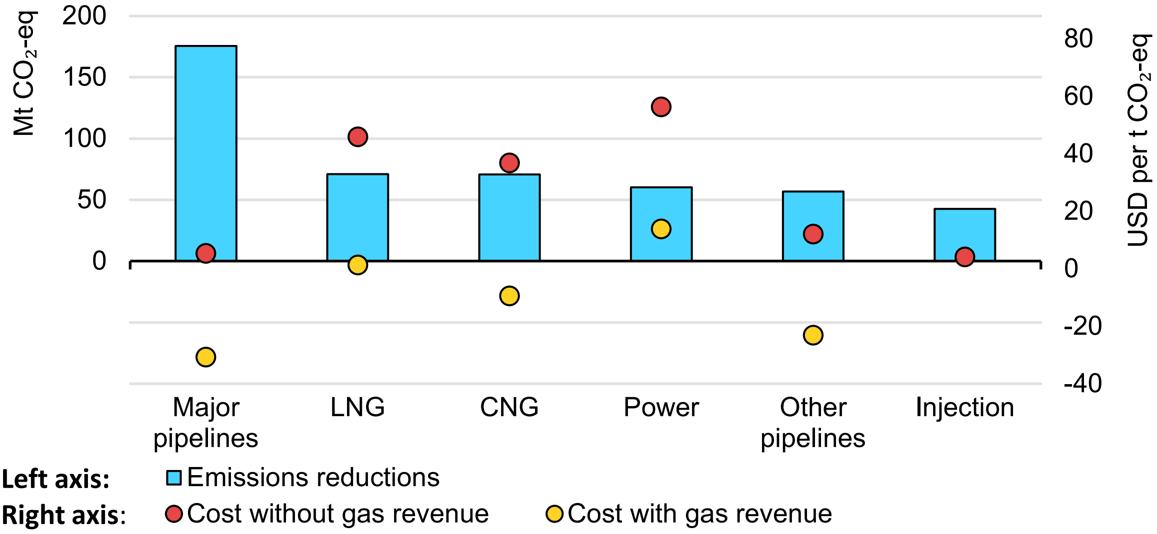
The costs of flaring reduction projects can vary significantly depending on the size and frequency of flaring and the distance to existing infrastructure. We estimate that around USD 70 billion upfront spending is required between 2022 and 2030 to achieve the flaring reductions in the NZE Scenario. The most cost-effective solution is to bring the gas to market via new pipeline connections to gas transmission or distribution grids, CNG or LNG terminals, and this is where most of the capital expenditure is directed. With the exception of gas injection, the gas that is saved can be resold, significantly lowering the net cost of abatement even at the low gas prices in the NZE Scenario. We estimate that two thirds of volumes flared could be avoided at no net cost because the value of the captured methane in the NZE Scenario is sufficient to cover the cost of the abatement measure; this share would be even higher in scenarios with higher natural gas prices.

Reported data on flaring and combustion efficiencies are often based on estimated emission rates that can vary substantially from the volumes recorded during measurement campaigns. Measuring flaring and venting levels is necessary for company accountability and to develop alternative options or lay a foundation for market-based mechanisms that favour low-emission oil and gas sources. Measurements should be made publicly available to help buyers, consumers and financial actors better understand scope 1 emissions.

New technologies have made it easier to monitor and reduce emissions. Flares can now be monitored on a near real-time basis, helping companies to identify bottlenecks and opportunities in operated and non-operated assets. Mobile mini-LNG or CNG production equipment can reduce the need for flaring and venting during well-testing and other short-term operations. Automated air/fuel ratio controls can ensure compressors and engines operate at optimal levels, reducing the amount of methane that escapes from combustion processes.

There are several efforts to cut down on flaring, including the Zero Routine Flaring by 2030, launched by the World Bank and the United Nations in 2015, which commits governments and companies to end routine flaring no later than 2030. Progress towards this goal has been relatively limited, however, and volumes of natural gas flared in 2022 were around the same level as in 2010. Achieving the pace and scale of reductions in flaring seen in the NZE Scenario will require strengthened and enforced policy, and industry and financial sector efforts.

Emissions reductions potential in 2022 and average cost of flaring reduction measures in the NZE Scenario



Notes: Abatement measures were selected based on flare size and distance from existing infrastructure. Gas income based on prices to 2030 in the NZE Scenario.

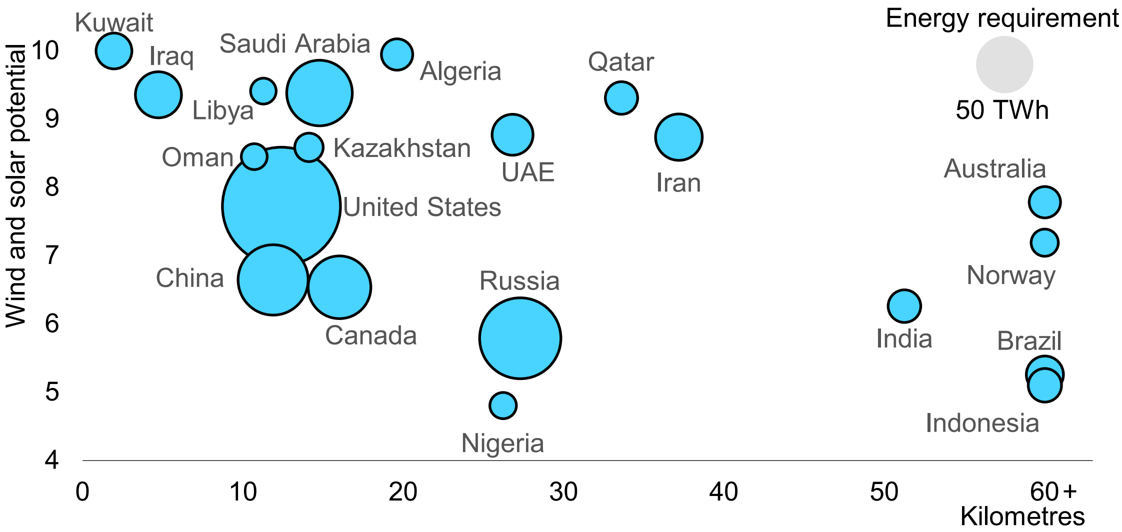
Sources: IEA analysis based on information provided by EDF, the World Bank Global Gas Flaring Reduction Partnership, the Methane Guiding Principle's Cost Model, and Capterio.

Electrify upstream operations

Electrifying operations cuts in half CO_2 emissions from upstream energy use in 2030

Oil and gas extraction requires a large quantity of energy to power drilling rigs, pumps, compressors, and other process equipment, while heat is used to keep drilling fluids or extracted oil at desired temperatures. A continuous supply of fuel to provide the energy required for upstream oil and gas operations is essential and diesel is often used to provide the energy required before production has started (i.e. during the drilling and development stage), and natural gas or electricity is often used during the production phase. The energy required for these upstream oil and gas processes resulted in more than 700 Mt CO_2 in 2022.

Average wind and solar potential and distance to nearest electricity connection for major oil and gas producers in 2022



Notes: Bubble size indicates total energy requirements in 2022 for upstream oil and gas production. The figure shows the twenty producers with the largest absolute requirements. Solar and wind potential are production-weighted averages calculated per square kilometre, normalised to a maximum score of five for each.

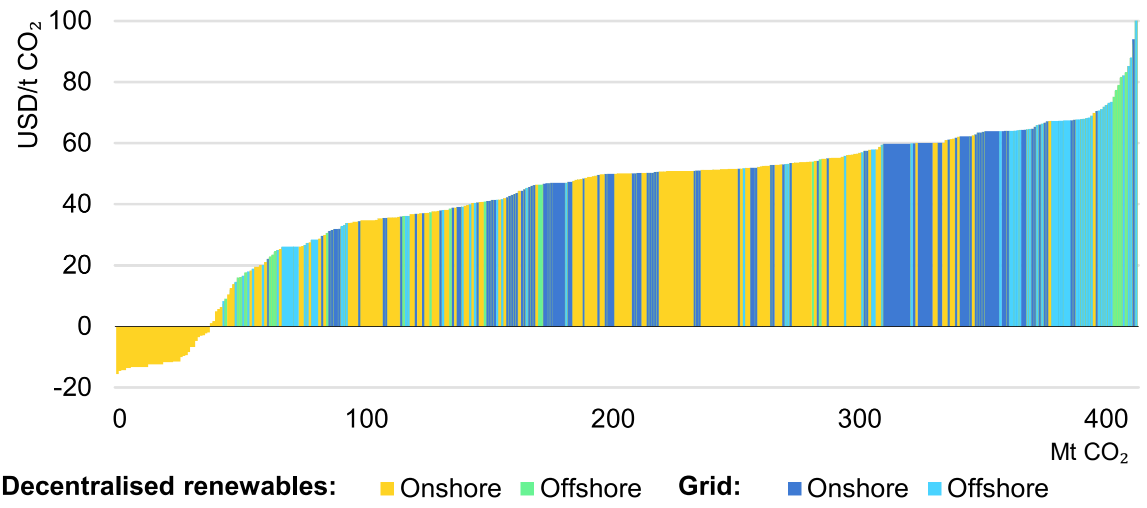
A large portion of the energy required at upstream facilities is to power electrical equipment, with the electricity produced using small-scale onsite natural gas generators. These are quite inefficient and also use some of the valuable products that could often be sold. Using more efficient equipment – such as swapping an open cycle gas turbine for combined cycle – can save around 30% of the energy required. But full electrification can lead to even greater efficiency improvements. More than half of global oil and gas production today lies within 10 km of an electricity grid and 75% takes place in an area with good wind or solar resources. The energy at upstream facilities could therefore be provided by electricity from a centralised grid or generated in a decentralised renewable energy system.

Norway has been leading efforts to electrify upstream oil and gas operations, with grid connections or dedicated offshore wind installations an integral part of its plan to reduce emissions by 70% from Norway's Continental Shelf production by 2040. BP has electrified a substantial portion of its assets in the Permian Basin in Texas. But there are few examples of large-scale actions being taken by other oil and gas producers, especially for existing assets.

Operators face several choices when implementing an electrification programme, including selecting the appropriate technology and design (whether to use direct or alternating current cables, or choosing the right mix of wind, solar and battery capacity), and assessing total costs in the context of the capital required to build renewable capacity or grid connections, as well as the price of the electricity and natural gas and the value of avoided CO_2. It is also important to ensure a continuous, reliable source of energy to maintain operations and ensure safety; there are several solutions available to do so, including the use of batteries, hybrid systems or the retention of existing assets for back-up power.

We have carried out a detailed geospatial analysis to assess the most feasible and cost-effective solution for electrifying the 8 200 oil and gas production sites that are in operation in the NZE Scenario in 2030.[6] We estimate that around 400 Mt CO_2 – three quarters of emissions from upstream energy use in 2030 – would be technically avoidable through electrifying facilities. The remainder cover operations that are impractical for full electrification, including those that require substantial amounts of heat and those with large process emissions (such as coal-to-liquids facilities). We also exclude production which takes place in remote locations far from grids or with low solar or wind resources.

Costs of electrifying oil and gas operations in 2030 in the NZE Scenario



Note: Costs take into account revenue from sales of oil and gas not used in operations.
Source: IEA analysis based on geospatial data from World Bank (2023), Global Solar Atlas (2023), Rystad Energy (2023).

[6] No new fields are developed in the NZE Scenario and so this assessment looks only at opportunities for electrifying existing fields, taking into account changes in production to 2030. Fields that stop producing before 2030 are not considered. For each field, the assessment examines current and future: upstream energy use, distance from an existing electricity grid, grid connection costs, electricity prices, emissions intensity of electricity, wind and solar potential and costs, and battery costs. Projections of prices and costs are based on data in the NZE Scenario to 2030. The choice of electrifying a site through grid connection or decentralised renewables, and the optimal mix of wind and solar capacity, is based on the option with the lowest net present value in each year.

Some of the lowest cost options are production sites close to electricity infrastructure in countries with relatively low electricity prices or in renewables-rich areas with plenty of available land (as in the Middle East and North Africa). Offshore sites are generally more costly to electrify as many platforms are far from the coast, are located in deep waters and operate in harsh environments.

In the NZE Scenario, emissions from energy use in oil and gas production are reduced by 270 Mt CO_2 in 2030 by means of electrification. This costs just over USD 260 billion to 2030, of which 10% is for grid connections, 35% is for purchasing electricity from the grid and 50% is for developing decentralised hybrid solar PV, wind and battery storage systems. The remainder is used to develop pipeline connections to nearby gas gathering pipelines to connect un-used natural gas to nearby markets. On average this would add around USD 0.3/boe at fields that are electrified.

Alongside the electrification of upstream oil and gas production, there are also opportunities further downstream – such as the use of electric motors to power the LNG liquefaction process (as is currently done in the Snøhvit terminal in Norway and the Freeport terminal in the United States) rather than using industrial open-cycle gas turbines (which can emit as much as 250 kg CO_2 per tonne LNG). Using grid electricity in place of gas in compressor stations can similarly reduce emissions associated with the transport of natural gas via transmission pipelines.

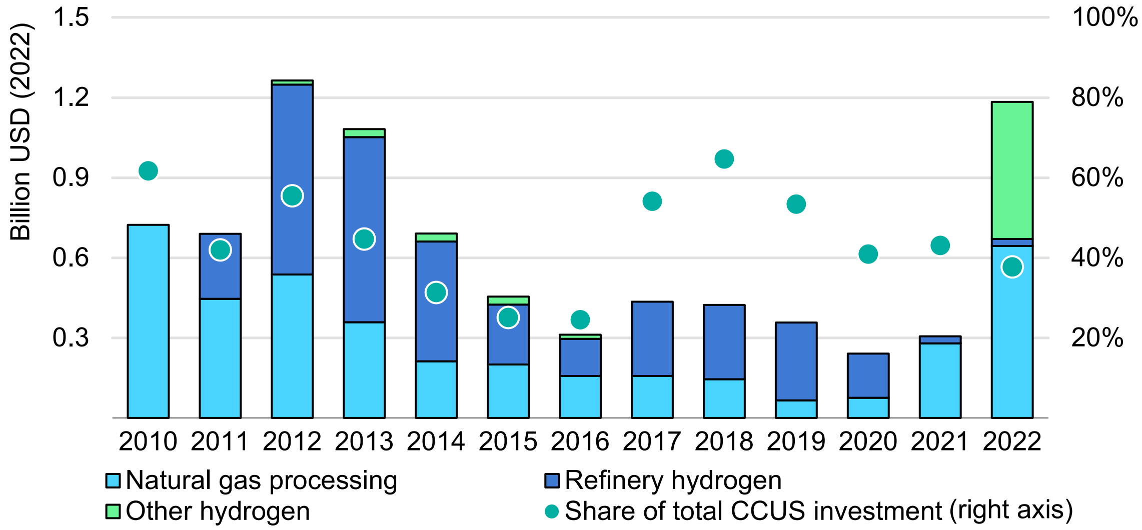
Most electrification options would incur a net cost to operators, even when accounting for efficiency gains and the sale of the additional oil and gas not required. Policy or regulatory incentives are therefore necessary to stimulate the required upfront investment. This could take the form of a CO_2 price – which provided the spur for development in Norway – or might come in the form of tax breaks or exemptions on a portion of electricity tariffs. Costs could be kept down if operators collaborate to build shared clean electricity infrastructure that would feed wider areas of production, an example being 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.

Deployment of CCUS

Oil and gas companies are already leaders in CCUS and boosting deployment would significantly cut their own emissions

The oil and gas industry is involved in 90% of CO_2 capture and storage capacity in operation around the world today. More than 40% of CCUS investment since 2010 has been in projects directly related to the oil and gas value chains. There are 15 large CCUS projects in operation that capture and store 25 Mt CO_2 per year from natural gas processing, mostly in Australia, Brazil, the People's Republic of China (hereafter "China"), the Middle East and the United States and another three refinery or upgrader facilities in Canada and the United States that each capture around 1 Mt CO_2 per year.

CCUS investment in oil and gas value chains and share of total CCUS investment



Source: Analysis based on IEA CCUS project database.

Several activities along the oil and gas supply chain result in highly concentrated sources of CO_2 emissions suitable for CCUS. In addition, once the CO_2 is captured and compressed, geological storage resources are often found close to existing oil and gas activities, and sometimes within their operational scope. There are three main processes to which CCUS can be applied to reduce the emissions intensity of oil and gas operations.

Gas processing. When extracted, natural gas can contain numerous impurities, including CO_2 that is usually removed before long distance transport and vented to the atmosphere.[7] We estimate that around 150 Mt of naturally occurring CO_2 is extracted each year through oil and gas operations of which 125 Mt CO_2 is vented to the atmosphere. Of the 25 Mt CO_2 that is captured, most is injected into oil fields to boost production but some is geologically stored at inactive fields. We estimate that it would cost USD 15-30/t CO_2 to capture and store most of these highly concentrated CO_2 streams, which would translate into an additional cost of USD 0.1/MBtu for extracting natural gas with a 5% CO_2 content. Where conditions

[7] For pipelines, CO_2 levels in natural gas have to be reduced to below 0.5% or sometimes as high as 3% (mole fraction basis). For LNG, the threshold is around 0.005%.

have been favourable in the United States, it has been possible to entirely cover this cost with revenue from the sale of CO_2 to oil producers.

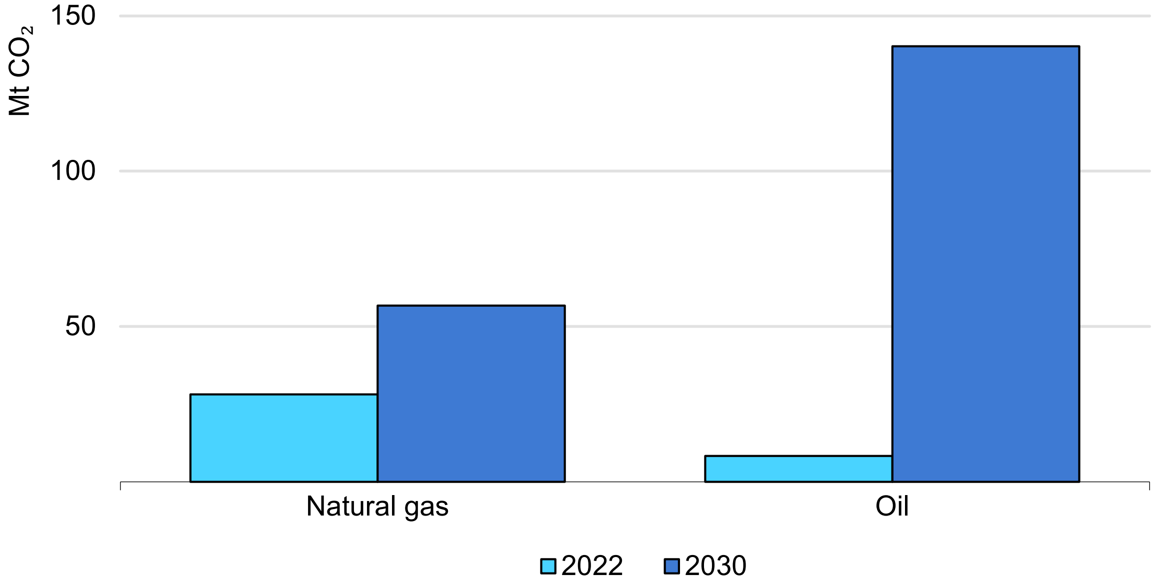
Refining and bitumen upgrading. Around 40 Mt of hydrogen is currently used to refine and upgrade oil globally and the CO_2 emissions from the transformation of fossil fuels to produce this hydrogen can be captured.[8] Hydrogen production units create a relatively pure stream of CO_2 that is often vented: this accounts for 60% of the total CO_2 emitted by a steam methane reformer and it is straightforward to capture it. Coal- and natural gas-based hydrogen units can be designed for 95% CO_2 capture to meet expectations for lower emissions intensity of hydrogen supply. CCUS can also reduce emissions from catalytic crackers, heat plants and power generation at refinery sites. Equipping CCUS to hydrogen production costs USD 15-45/t CO_2 avoided (for coal) or USD 50-80/t CO_2 avoided (for natural gas), with costs around twice as high for other onsite CO_2 sources where the sizes of the individual CO_2 streams are smaller. Other options to reduce emissions from refineries include switching to the use of low-emissions electrolytic hydrogen (see next section) and electrifying heat and power supplies; these may be more cost-effective options in some cases.

LNG liquefaction. Liquefying natural gas requires cooling it to -162 °C, which is an energy intensive process that is usually powered by consuming a portion of the gas flowing to the (often remote) facility. The amount used in this way varies markedly between facilities but averages around 9% globally. In addition to any venting of naturally-occurring CO_2, this means around 2-3 tonnes of CO_2 is emitted for every ten tonnes of LNG produced. There are no projects in operation today that use CCUS to reduce these process emissions, but it could reduce emissions by around 90%. Costs would vary by project scale and experience but would likely average around USD 40/t CO_2 avoided which would translate into around a USD 0.25/MBtu increase in the cost of the liquefaction process (around a 20% increase in costs).

In the NZE Scenario, CO_2 captured from these three applications grows from around 25 Mt CO_2 in 2022 to 160 Mt CO_2 in 2030. The largest increase comes from deploying CCUS in the oil value chain, both on site at refineries and at the production sites of external suppliers who sell hydrogen to refiners (around 30% of the hydrogen consumed in refineries today comes from these external suppliers). Achieving this level of CCUS deployment in 2030 would require around USD 100 billion investment to 2030, mostly for capital costs. This investment continues to provide emissions reductions after 2030. There are even greater emissions reductions from across the oil and gas supply chain through the use of CCUS after 2030.

[8] This section focuses on low-emissions hydrogen produced using CCUS. Refineries can also reduce their emissions by substituting existing hydrogen demand for low-emissions hydrogen using water electrolysis and can select whichever approach is most competitive in a given location. Hydrogen from electrolysis is discussed in the next section.

CO_2 emissions avoided globally through CCUS in the natural gas and oil value chains in the NZE Scenario



Note: CO_2 emissions avoided are lower than the volume of CO_2 captured due to the reduction in efficiency of processes because of CO_2 capture and compression.

Learnings from the financing, construction and operation of CCUS at gas processing and hydrogen facilities this decade in the NZE Scenario also contribute to cost reductions for CCUS in other sectors, such as cement production. The involvement of oil and gas companies can also help develop new geological CO_2 storage resources to underpin future deployment. For example, three oil companies are involved in the Northern Lights CO_2 storage facility that will store CO_2 from cement and waste-to-energy plants in Norway.

In the NZE Scenario, policies are soon introduced to boost the deployment of CCUS, including through measures that mitigate risks for large-scale CO_2 storage development, offer performance-based payments for proven CO_2 avoidance, and create markets for low-emissions products. There have been a number of positive policy developments and incentives recently in this regard. These include tax credits of up to USD 85/t CO_2 under the US Inflation Reduction Act, which can be coupled with support from Low Carbon Fuels Standard certificates in some states, and various support schemes for low-emissions hydrogen around the world. In Europe, the European Commission has proposed making EU oil and gas supply conditional on investment in CO_2 storage resources. In oil-producing locations, first-movers may store the CO_2 through enhanced oil recovery to improve project economics.

Use of low-emissions electrolysis hydrogen

Electrolysis hydrogen plays a smaller role to reduce oil and gas emissions to 2030 but enables much larger reductions later on

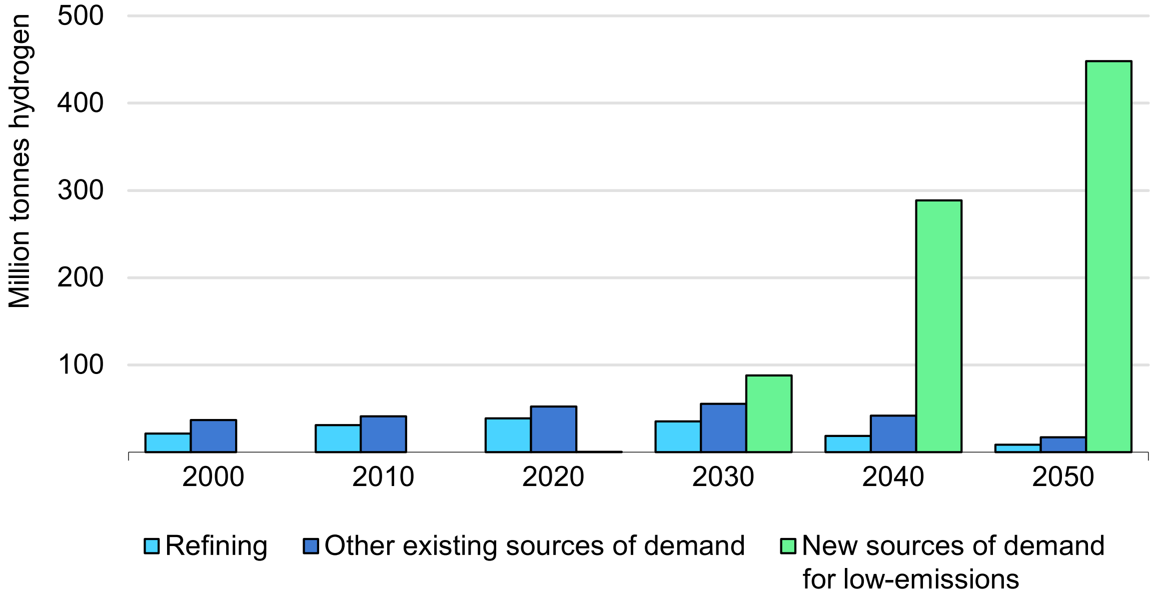
Four of the five largest projects under construction globally to produce hydrogen from electrolysis are being developed by oil and gas companies or will supply hydrogen to a refinery.[9] This includes a 260 MW electrolyser to produce hydrogen for a refinery and a 200 MW electrolyser for use at a coal-to-chemicals plant, both in China, and a 200 MW electrolyser to replace hydrogen from a natural gas reformer in the Netherlands. Around the world, oil and gas companies, including those engaged in natural gas distribution, are involved in nearly 50 electrolysis projects in operation or development, representing more than 1.6 GW of capacity.

Around 40 Mt of hydrogen is used by refineries today, more than two-fifths of global hydrogen demand, resulting in over 200 Mt CO_2 annually. In the NZE Scenario, the declines in oil consumption mean the required volumes of hydrogen falls slightly but demand in 2030 is similar to levels in 2015. There are a number of reasons why refineries are well suited for the deployment of low-emissions hydrogen:

- They can accommodate a new source of low-emission hydrogen without the need for new end-user equipment. This avoids the need to synchronise investment in low-emissions hydrogen supply with investment in hydrogen demand technologies. In some cases, existing sources of hydrogen can be kept online to ensure continuous supply during a transition period.
- They are often co-located with other industrial sources of hydrogen demand, which can share some project risks and diversify hydrogen supplies over time.
- They are often in locations that are well-suited for developing the renewable electricity (such as offshore wind or solar PV) or CO_2 storage that are essential for low-emissions hydrogen and minimise the need for new infrastructure to move electricity, hydrogen or CO_2.
- They are typically coastal and so can be linked into the planning of future import or export hubs for hydrogen and hydrogen-based fuels.

[9] This section focuses on low-emissions hydrogen produced from water electrolysis. Refineries can also reduce their emissions by substituting existing hydrogen demand for low-emissions hydrogen produced with CCUS, as discussed in the previous section.

Evolution of hydrogen demand in the NZE Scenario



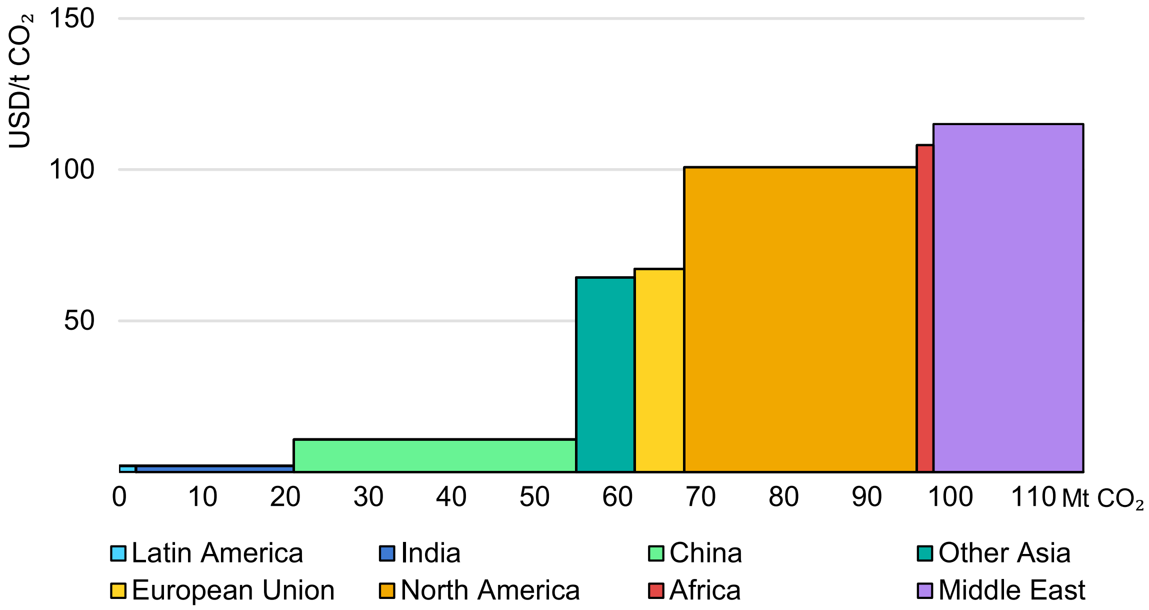
Notes: Other existing sources of demand include ammonia, methanol and direct reduction of iron. New sources of demand for low-emissions hydrogen include inputs to hydrogen-based fuels production, iron and steel, transport, biofuels production, electricity storage and power generation, and heat generation.

We estimate that the cost of avoiding one tonne of CO_2 through the use of low-emissions electrolysis hydrogen in 2030 will range widely depending on the relative prices of fossil fuels and costs of renewable electricity. Costs are lowest in regions where the imported natural gas prices are relatively high and renewable electricity costs relatively low, which includes India and parts of Latin America. In these regions, this would add around USD 0.2/bbl to the cost of refining a barrel of oil. In China, lower capital costs of electrolyser installation reduce the cost gap with coal-based hydrogen to just USD 0.2/kg of hydrogen. Between them, China and India represent 50 million tonnes of CO_2 abatement potential. In Europe and North America, the costs of avoiding CO_2 are less favourable, but would still only add USD 2/bbl to the cost of refining.

In the NZE Scenario, around 6 Mt of low-emissions electrolysis hydrogen is projected to be used in refineries in 2030. Around 65% of this is produced on site at refineries themselves and the remainder is purchased from external suppliers. In total, this requires around 60 GW of electrolyser capacity and around 280 TWh of low-emissions electricity.

This would cost just over USD 80 billion, split between capital expenditure for electrolysers and new renewable capacity to produce the hydrogen onsite (35%) and operational costs and purchases of low-emissions electrolysis hydrogen from third party suppliers (65%). This investment yields other co-benefits by reducing costs and risks for other projects related to new sources of hydrogen demand (such as electricity storage, hydrogen-based fuels, and steel production).

Cost of avoiding CO_2 emissions with low-emissions electrolysis hydrogen, and CO_2 emissions from refinery hydrogen by region in the NZE Scenario in 2030



Notes: Regions not shown have higher average abatement costs. Levelised costs based on average fossil fuel and costs of the cheapest dedicated renewable electricity installations per region in the NZE Scenario in 2030, inclusive of capital costs of the existing hydrogen source.

Achieving the scale up of low-emissions electrolysis hydrogen in the NZE Scenario requires policies to create a well-functioning market. This can be achieved through a production-based economic incentive, for example as direct payments or tax credits for producing low-emissions hydrogen or oil products with a low emissions intensity. Regulatory constraints could also be used, for example by restricting the use of hydrogen or sale of oil products with an emissions intensity above a stated level (this could be in the form of a cap-and-trade system, including fuels standards with tradeable certificates). Robust measurement and reporting frameworks are also needed, which would need to include clear rules on the eligibility of different sources of hydrogen for support programmes, based on emissions intensity, and compatible international agreements to govern any imports. Permitting timelines will also need to be shortened considerably for renewable power, pipeline and electrolyser capacity and, for low-emissions electrolysis hydrogen produced by external sources and sold to refiners, rules established over pipeline and storage infrastructure access.

Technical annex

Modelling approach for emissions in 2022

The Global Energy and Climate Model tracks a barrel of oil or cubic metre of natural gas from where it is produced to where it is refined or processed and finally to where it is consumed. In this analysis we focus on scope 1 and 2 CO_2 and methane emissions from oil and gas operations. Methane emissions are taken from the Global Methane Tracker 2022.

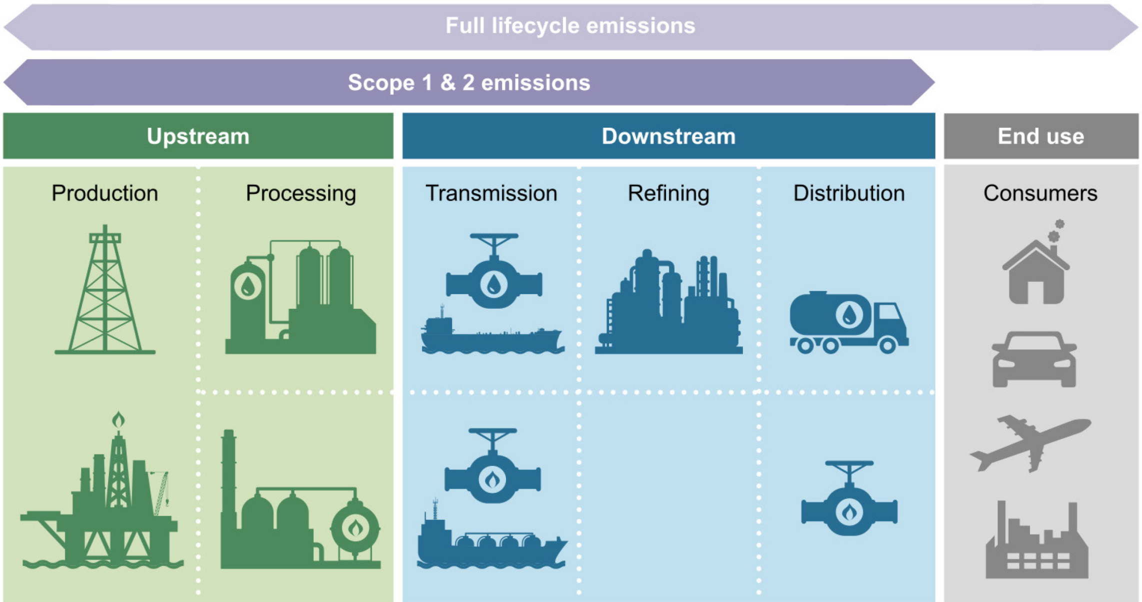
For upstream CO_2 emissions, we generate country-specific energy intensities for each type of oil and gas production that take into account the various processes used along production stages (e.g. exploration, development, drilling, extraction, processing, maintenance). The intensities are derived from the Oil Climate Index plus Gas tool (OCI+) which is based on a detailed field-by-field dataset and was created by the Rocky Mountain Institute (RMI) using the Oil Production Greenhouse Gas Emissions Estimator (OPGEE, version 3.0a). Intensities are projected into the future taking into account continued technological improvements (which tend to reduce the energy intensity of production) and resource depletion (which tend to increase the energy intensity).

We account for CO_2 emissions from gas flaring (mostly from oil fields) based on data from the World Bank Global Gas Flaring Reduction Partnership and CO_2 venting (mostly from gas fields). For downstream CO_2 emissions, transport energy use and emissions take into account the different trade routes and whether the transport is by ship or pipeline. Refining emissions take into account the different qualities of oil used as feedstock and the level of the processing required to provide the end-use products demanded by consumers. Hydrogen needs in refining operations take into account differences in the sulphur content of crude oil and the allowed sulphur content of final products. Values are adjusted based on the process-level information in the Petroleum Refinery Life Cycle Inventory Model (PRELIM).

The global average array of oil products produced from a barrel of oil equivalent (the "product slate") can vary substantially between different individual refineries. However, refineries generally try to limit the production of heavier products, and so at a regional level there is only a slight variation in the emissions from combusting a barrel of oil equivalent. The additional emissions associated with converting a barrel of extra heavy oil into synthetic crude oil are captured in our modelling as refining emissions. Some oil products are used as feedstocks and not combusted, reducing the global average emissions associated with all oil use.

Our analysis does not consider all emissions that could be included in a full lifecycle assessment. We do not include the energy used in manufacturing the drilling rigs or the steel used in wells or pipelines; these amounts are not easily available in energy statistics and are likely to be dwarfed by the direct use of energy. We also do not consider land-use CO_2 emissions from clearing areas for production facilities in onshore areas. Previous assessments have indicated that these are likely to be relatively small - less than 1% of total lifecycle emissions of a barrel of conventional crude oil – although emissions can be very site specific, depending on how the land was used prior to construction of the facility, and are subject to large uncertainty ranges.

Scope of emissions included in analysis



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