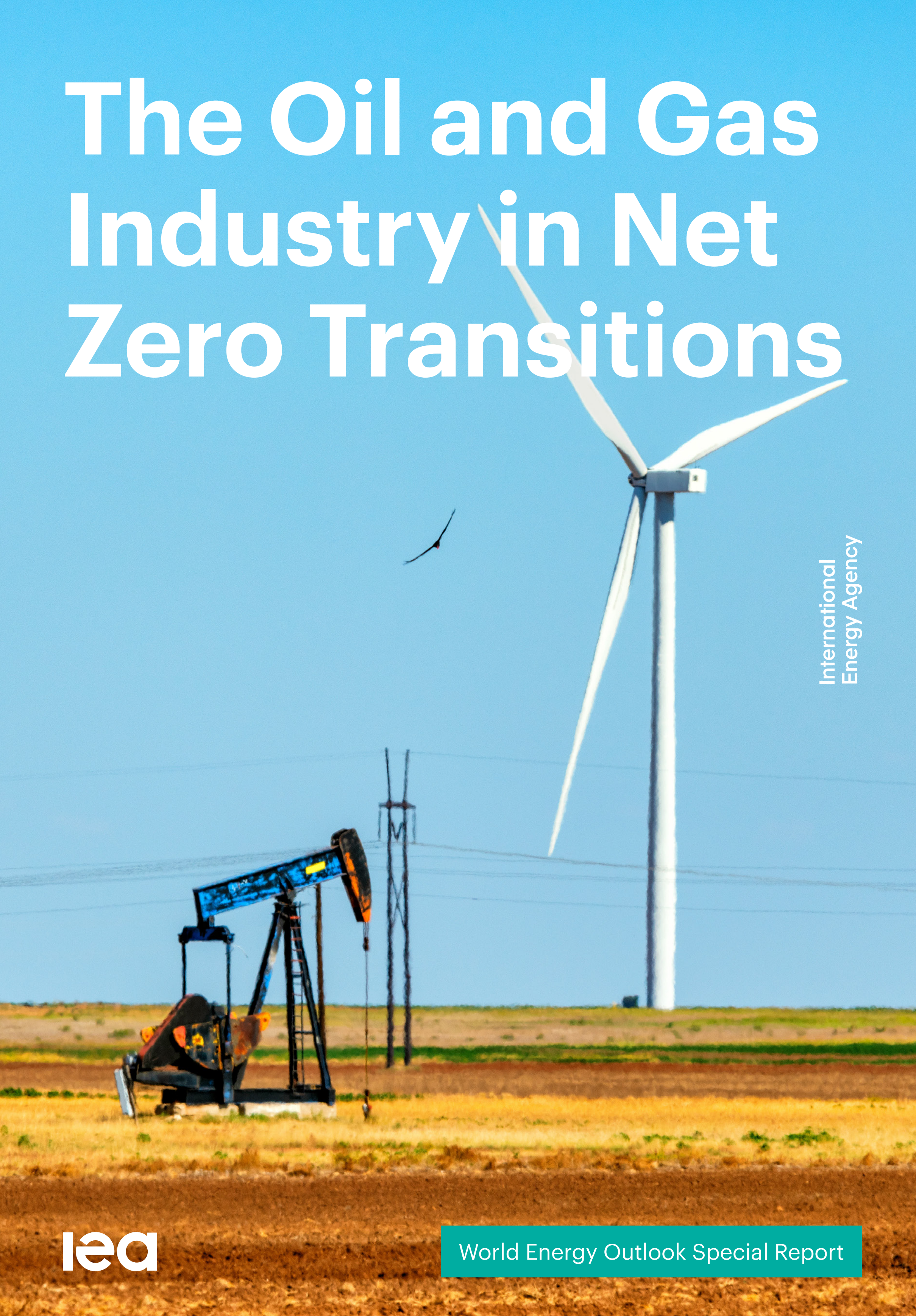
The Oil and Gas Industry in Net Zero Transitions



International Energy Agency

World Energy Outlook Special Report

INTERNATIONAL ENERGY AGENCY

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In the energy and climate worlds, everyone has an opinion about the role of the oil and gas industry in the transition to net zero emissions. For some, the conclusion is unambiguous. The oil and gas industry is an obstacle to change, so successful transitions require relegating oil and gas companies to history. For others, the capabilities and capital the industry holds can be instruments of change – potentially important ones.

Perspectives on this issue are complicated by the size and diversity of the industry itself. There are many different companies engaged in oil and gas, from small independent firms to huge national oil companies – from technology providers to market traders. And there are many different stances across the industry on energy transitions, from outright opposition through to grudging acceptance and, in some cases, active pursuit of new opportunities.

A productive discussion on this crucial topic requires a solid evidence base and dispassionate analysis. This is what the International Energy Agency (IEA) provides in this new special report. It is by no means our first such in-depth analysis of the sector: we have published a range of useful studies over the years that have highlighted the urgent need for change, most notably *The Oil and Gas Industry in Energy Transitions*, in January 2020. This new special report brings together, updates and expands that analysis in ways that make this the most comprehensive and authoritative work on this topic to date.

Since 2020, important changes have taken place in the global energy sector as the world has contended with the turmoil of the Covid-19 pandemic and the global energy crisis – and as an increasing number of governments have raised their climate ambitions and launched major policy initiatives to accelerate clean energy transitions. As a result, we have seen a 40% increase in clean energy investment – and impressive momentum in key technologies such as solar PV, wind and electric vehicles. This means that for the first time, we see peaks in demand for all of the fossil fuels before 2030, based on today's policy settings. These settings are not yet strong enough to deliver steep declines in demand on the other side of the peaks. However, if governments deliver in full on their national energy and climate pledges, and even more so if they manage to shift the world onto the narrow pathway to limiting global warming to 1.5 °C, the consequences for the oil and gas industry will be profound.

This report shows that the industry can and must do much more to respond to the threat of climate change. Regardless of which pathway the world follows, climate impacts will become more visible and severe over the coming years, increasing the pressure on all elements of society to find solutions. The industry therefore faces a choice – a moment of truth – over its engagement with clean energy transitions. So far, its engagement has been minimal: less than 1% of global clean energy investment comes from oil and gas companies. But there is no part of the industry that will be left unaffected by the transition to net zero. Every part of the industry needs to respond.

The uncomfortable truth that the industry needs to come to terms with is that successful clean energy transitions require much lower demand for oil and gas, which means scaling back oil and gas operations over time – not expanding them. There is no way around this. So while all oil and gas producers needs to reduce emissions from their own operations, including methane leaks and flaring, our call to action is much wider.

To escape the narrowing walls of their businesses based on traditional fuels, producers need to embrace the clean energy economy. This report explores what these opportunities look like, both for companies and for economies that rely heavily on oil and gas revenues. And with all of the above in mind, the report spells out clearly what it really means for producers to align with the Paris Agreement and with the 1.5 °C goal.

I would like to thank the excellent team of IEA colleagues who produced this extremely important study with all the nuance and objectivity that the subject requires – under the leadership of my colleagues Tim Gould, Chief Energy Economist, and Christophe McGlade, Head of the Energy Supply Unit. It provides important input to the discussions at the upcoming COP28 climate change conference in Dubai – but more than that, I am convinced this will be a reference work for many years to come.

Dr Fatih Birol
Executive Director
International Energy Agency

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Marina Dos Santos, Eleni Tsoukala and **Reka Koczka** provided essential support.

Justin French-Brooks carried editorial responsibility.

Valuable comments and feedback were provided by other senior management and numerous other colleagues within the International Energy Agency. In particular Mary Warlick, Toril Bosoni, Joel Couse, Laura Cozzi, Dan Dorner, Rebecca Gaghen, Timur Gül, Ilkka Hannula, Dennis Hesseling, Brian Motherway, and Hiro Sakaguchi.

Thanks go to the IEA Communications and Digital Office for their help to produce the report and website materials, particularly to Jethro Mullen, Poeli Bojorquez, Curtis Brainard, Jon Custer, Hortense De Roffignac, Astrid Dumond, Merve Erdil, Grace Gordon, Julia Horowitz, Oliver Joy, Isabelle Nonain-Semelin, Julie Puech, Robert Stone, Sam Tarling, Clara Vallois, Lucile Wall, Therese Walsh and Wonjik Yang. The IEA Office of the Legal Counsel, Office of Management and Administration and Energy Data Centre provided assistance throughout the preparation of the report.

Peer reviewers

Many senior government officials and international experts provided input and reviewed preliminary drafts of the report. Their comments and suggestions were of great value. They include:

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Atul Arya	S&P Global
Zubin Bamji	World Bank
Imene Ben Rejeb-Mzah	BNP Paribas
Chris Besson	Independent consultant
Jason Bordoff	Columbia University, United States
Siân Bradley	Beyond Oil and Gas Alliance (BOGA)
Mark Brownstein	Environmental Defense Fund
Nick Butler	King's College London
Michael Cohen	BP
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Annexes

A moment of truth is coming for the oil and gas industry

Structural changes in the energy sector are now moving fast enough to deliver a peak in oil and gas demand by the end of this decade under today's policy settings. After the peak, demand is not currently set to decline quickly enough to align with the Paris Agreement and the 1.5 °C goal. But if governments deliver in full on their national energy and climate pledges, then oil and gas demand would be 45% below today's level by 2050 and the temperature rise could be limited to 1.7 °C. If governments successfully pursue a 1.5 °C trajectory, and emissions from the global energy sector reach net zero by mid-century, oil and gas use would fall by 75% to 2050.

This new IEA report explores what oil and gas companies can do to accelerate net zero transitions and what this might mean for an industry which currently provides more than half of global energy supply and employs nearly 12 million workers worldwide. Since 2018, the annual revenues generated by the oil and gas industry have averaged close to USD 3.5 trillion. Around half of this went to governments, while 40% went back into investment and 10% was returned to shareholders or used to pay down debt. The implications of net zero transitions are far from uniform: the industry encompasses a wide range of players, from small, specialised operators to huge national oil companies (NOCs). While attention often focuses on the role of the majors, which are seven large, international players, they hold less than 13% of global oil and gas production and reserves. NOCs account for more than half of global production and close to 60% of the world's oil and gas reserves.

The industry's engagement with clean energy transitions will be a key topic at COP28, but this report provides a reference for a debate that will continue well beyond the UN climate summit in Dubai.

Most oil and gas companies are watching energy transitions from the sidelines

Oil and gas producers account for only 1% of total clean energy investment globally. More than 60% of this comes from just four companies, out of thousands of producers of oil and gas around the world today. For the moment the oil and gas industry as a whole is a marginal force in the world's transition to a clean energy system.

The first-order task is to slash emissions from company operations

While there is no single blueprint for change, there is one element that can and should be in all company transition strategies: reducing emissions from the industry's own operations. As things stand, less than half of current global oil and gas output is produced by companies that have targets to reduce these emissions. A far broader coalition – with much more ambitious targets – is needed to achieve meaningful reductions across the oil and gas industry. The production, transport and processing of oil and gas results in just under 15% of global energy-related greenhouse gas emissions. This is a huge amount, equivalent to all energy-related greenhouse gas emissions from the United States.

To align with a 1.5 °C scenario, these emissions need to be cut by more than 60% by 2030 from today's levels and the emissions intensity of global oil and gas operations must near zero by the early 2040s. These are appropriate benchmarks for industry-wide action on emissions, regardless of the future scenario. The emissions intensity of the worst performers is currently five- to ten-times higher than the best. Methane accounts for half of the total emissions from oil and gas operations. Tackling methane leaks is a top priority and can be done very cost-effectively – but it is not the only priority.

Transitions will hurt the bottom line for companies focused on oil and gas

The volatility of fossil fuel prices means that revenues could fluctuate from year to year – but the bottom line is that oil and gas becomes a less profitable and a riskier business as net zero transitions accelerate. Prices and output are generally lower and the risk of stranded assets is higher, especially in the midstream sector that includes refineries and facilities for liquefied natural gas. If expectations are that demand and prices follow a scenario based on today's policy settings, that would value today's private oil and gas companies at around USD 6 trillion. If all national energy and climate goals are reached, this value is lower by 25%, and by 60% if the world gets on track to limit global warming to 1.5 °C.

Oil and gas projects currently produce slightly higher returns on investment, but those returns are less stable. We estimate that the return on capital employed in the oil and gas industry averaged around 6-9% between 2010 and 2022, whereas it was 6% for clean energy projects. Oil and gas returns varied greatly over time compared with more consistent returns for clean energy projects.

Oil and gas investment is needed in all scenarios, but the demand trajectory in a 1.5 °C world leaves no room for new fields

Continued investment in oil and gas supply is needed in all scenarios, but the USD 800 billion it currently invests each year is double what is required in 2030 to meet declining demand in a 1.5 °C scenario. Investment in existing and some new fields is necessary in a world that achieves national energy and climate pledges, although there is no need in aggregate for new exploration. In a scenario that hits global net zero emissions by 2050, declines in demand are sufficiently steep that no new long lead-time conventional oil and gas projects are required. Some existing production would even need to be shut in. In 2040, more than 7 million barrels per day of oil production is pushed out of operation before the end of its technical lifetime in a 1.5 °C scenario.

In net zero transitions, new project developments face major commercial risks and could also lock in emissions that push the world over the 1.5 °C threshold. Producers need to explain how any new resource developments are viable within a global pathway to net zero emissions by 2050 and be transparent about how they plan to avoid pushing this goal out of reach.

Not all producers can be the last ones standing

Many producers say they will be the ones to keep producing throughout transitions and beyond. They cannot all be right. Oil and gas production is vastly reduced in net zero transitions but does not disappear. Even in a 1.5 °C scenario, some 24 million barrels per day of oil is produced in 2050 (three-quarters is used in sectors where the oil is not combusted, notably in petrochemicals), as well as some 920 billion cubic metres of natural gas, roughly half of which is used for hydrogen production.

The distribution of future supply among producers will depend on the weight assigned to lowering costs, ensuring diversity of supply, reducing emissions, and fostering economic development. Market forces naturally favour the lowest-cost production, but that leads to a high concentration in supply among today's major resource holders, notably in the Middle East. Prioritising the least emissions-intensive sources drives progress towards climate goals, but this often favours low-cost producers, so supply still becomes more concentrated. It is much better for transitions if all producers take targeted action to reduce their emissions. If production from low-income producers is favoured, these projects may not ultimately be very profitable in a well-supplied market. And if countries prefer domestically produced oil and gas as a way to buttress energy security, they reduce reliance on others but risk finding themselves with relatively high-cost projects in a low-price world.

The oil and gas industry is well placed to scale up some crucial technologies for net zero transitions…

Some 30% of the energy consumed in a net zero energy system in 2050 comes from low-emissions fuels and technologies that could benefit from the skills and resources of the oil and gas industry. These include hydrogen and hydrogen-based fuels; carbon capture, utilisation and storage (CCUS); offshore wind; liquid biofuels; biomethane; and geothermal energy. Oil and gas companies are already partners in a large share of planned hydrogen projects that use CCUS and electrolysis. The oil and gas industry is involved in 90% of CCUS capacity in operation around the world. CCUS and direct air capture are important technologies for achieving net zero emissions, especially to tackle or offset emissions in hard-to-abate sectors. For the moment, only around 2% of offshore wind capacity in operation was developed by oil and gas companies. Plans are expanding, however, and the technology frontier for offshore wind – including floating turbines in deeper waters – moves this sector closer to areas of oil and gas company strength. In addition, industry skills and infrastructure, including existing retail networks and refineries, give the industry advantages in areas like electric vehicle charging and plastic recycling.

…but this requires a step-change in the industry's allocation of investment

Companies that have announced a target to diversify their activities into clean energy account for just under one-fifth of current oil and gas production. The oil and gas industry invested around USD 20 billion in clean energy in 2022, some 2.5% of its total capital spending. In this report, we offer a new framework for assessing the strategies of oil and gas companies and the extent to which they are making a meaningful contribution to transitions.

For producers that choose to diversify and are looking to align with the aims of the Paris Agreement, our bottom-up analysis of cash flows in a 1.5 °C scenario suggests that a reasonable ambition is for 50% of capital expenditures to go towards clean energy projects by 2030, on top of the investment needed to reduce scope 1 and 2 emissions.

Not all oil and gas companies have to diversify into clean energy, but the alternative is to wind down traditional operations over time. Some companies may take the view that their specialisation is in oil and natural gas and so decide that – rather than risking money on unfamiliar business areas – others are better placed to allocate this capital. But aligning their strategies with net zero transitions would then require them to scale back oil and gas activities while investing in scope 1 and 2 emissions reductions.

Two pitfalls for the discussion about the future of oil and gas

A productive debate about the oil and gas industry in transitions needs to avoid two common misconceptions. **The first is that transitions can only be led by changes in demand.** "When the energy world changes, so will we" is not an adequate response to the immense challenges at hand. An imbalanced focus on reducing supply is equally unproductive, as it comes with a heightened risk of price spikes and market volatility. In practice, no one committed to change should wait for someone else to move first. Successful, orderly transitions are collaborative ones, in which suppliers work with consumers and governments to expand new markets for low-emissions products and services.

The second is excessive expectations and reliance on CCUS. Carbon capture, utilisation and storage is an essential technology for achieving net zero emissions in certain sectors and circumstances, but it is not a way to retain the status quo. If oil and natural gas consumption were to evolve as projected under today's policy settings, this would require an inconceivable 32 billion tonnes of carbon captured for utilisation or storage by 2050, including 23 billion tonnes via direct air capture to limit the temperature rise to 1.5 °C. The necessary carbon capture technologies would require 26 000 terawatt hours of electricity generation to operate in 2050, which is more than global electricity demand in 2022. And it would require over USD 3.5 trillion in annual investments all the way from today through to mid-century, which is an amount equal to the entire industry's annual average revenue in recent years.

Producer economies face major uncertainties, but their energy advantages are not lost in transition

Economies that are heavily reliant on oil and gas revenues face some stark choices and pressures in energy transitions. These choices are not new, but the prospect of falling oil and gas demand adds a timeline and a deadline to the process of economic diversification. Transitions create powerful incentives to accelerate the pace of change while also draining a source of revenue that could finance it. Compared with the annual average between 2010 and 2022, per capita net income from oil and natural gas among producer economies is 60% lower in 2030 in a 1.5 °C scenario. New producers entering the market face additional challenges, as they may overestimate the bounty that might lie ahead and underestimate the hazards. Many producers are also heavily exposed to risks from a changing climate, which stand to further disrupt the security of energy supply.

The challenges are formidable, but there are workable net zero energy strategies available to producer economies and national oil companies. Today's producer economies retain energy advantages even as the world moves away from fossil fuels. In most cases, today's major producers of low-cost hydrocarbons also have expertise and ample, under-utilised renewable energy resources that could anchor positions in clean energy value chains and low-emissions industries. Reducing emissions from traditional supplies, including end-use emissions; putting domestic energy systems on a cleaner footing by phasing out inefficient subsidies and boosting clean energy deployment; and developing low-emissions products and services offer a way forward.

Will the oil and gas industry be part of the solution?

Our scenarios plot out how the transition could be achieved, but the baseline expectation should be for a volatile and bumpy ride. Declining markets are difficult to plan for, and the potential for disruption also comes from geopolitical tensions and increased incidences of extreme weather. Governments need to be vigilant for risks to the affordability and security of supply. The implications of any physical disruptions to supply are felt most strongly in emerging and developing economies in Asia, whose share of global crude oil imports rises from 40% today to 60% in 2050 in a scenario that meets national energy and climate goals. On the supply side, even as overall demand falls back, the Middle East plays an outsize role in global markets as a low-cost producer of both oil and gas.

Dialogue across all parts of oil and gas value chains remains essential to deliver an orderly shift away from fossil fuels – and to ensure that today's producers have a meaningful stake in the clean energy economy. The industry must change, but this dialogue also needs clear signals from consumers on the direction and speed of travel to guide investment decisions, to assign value to oil and gas with lower emissions intensities, to develop markets for low-emissions fuels, and to collaborate on technology innovation. Energy transitions can happen without the engagement of the oil and gas industry, but the journey to net zero will be more costly and difficult to navigate if they are not on board.

Oil and gas in net zero transitions

SUMMARY

- Around 97 mb/d of oil and 4 150 bcm of natural gas were consumed globally in 2022. This resulted in just over 18 Gt CO_2 emissions, around half of total energy-related CO_2 emissions. Recent momentum in deploying clean energy technologies means that oil and gas demand peak before 2030 in the Stated Policies Scenario (STEPS), but the declines after these peaks are not steep enough to achieve the world's climate goals.
- Net zero transitions require a huge acceleration in clean energy technology deployment and faster reductions in oil and gas use. In the Announced Pledges Scenario (APS), oil and gas demand decline by around 2% each year on average to 2050 (to 55 mb/d and 2 400 bcm) and in the Net Zero Emissions by 2050 (NZE) Scenario they fall by more than 5% each year on average to 2050 (to 24 mb/d and 920 bcm).
- Attention on the oil and gas industry often focuses on the large international oil and gas companies (the "majors"), but they own less than 13% of global oil and gas production and reserves. By comparison, national oil companies own more than half of production and close to 60% of reserves.
- Major challenges lie ahead for midstream infrastructure in net zero transitions. The refining sector reduces its output of traditional products like gasoline and diesel, and focuses more on petrochemical feedstocks and products like asphalt and bitumen. Global liquefied natural gas (LNG) trade sees strong near-term growth, but trade peaks in the APS before 2035 and the utilisation of export terminals drops; in the NZE Scenario, demand for LNG can be met in aggregate by plants already in operation.
- In the APS and NZE Scenario, investment in existing oil and gas assets continues, but with very different outcomes for new project development. In the APS, new oil and gas projects are needed, although in aggregate there would be no need for further oil and gas exploration. In the NZE Scenario, falling demand means that no new long lead time conventional oil and gas projects are approved for development and, after 2030, a number of projects are closed before they reach the end of their technical lifetime.
- Many producers have set out why they think their resources should be preferred for development in net zero transitions. Some say that they have the lowest production costs or emission intensities; others claim that they are a better option for energy security; and some indicate that new oil and gas developments are needed to improve welfare. In the demand environment of the NZE Scenario, any new oil and gas resource developments would need to be matched by production reductions elsewhere to avoid oversupply and fossil fuel lock-in.
- Both over- and underinvestment in fossil fuels carry risks for secure and affordable transitions. Sequencing the decline in oil and gas investment and the increase in clean energy investment is vital to avoid damaging price spikes or supply gluts. At present, risks appear to be weighted more towards overinvestment than the opposite.

1.1 Introduction

This report explores the outlook for oil and natural gas producers in net zero transitions. Oil and gas account for around half of today's global energy supply, providing valuable energy services to consumers around the world but also resulting in over 18 Gt CO_2 emissions. Some of the services provided by oil and gas can be replaced with relative ease by clean energy technologies, as witnessed by the rise of electric vehicles (EVs) and renewable sources of power generation. Others are more difficult to replace, such as seasonal balancing for power systems in the case of gas, or long-distance air travel in the case of oil. The position of oil and gas in the energy mix will not be transformed overnight. But it has to change, and change dramatically, if the world is to avoid severe damage from a changing climate. This analysis examines the contours and implications of such a process. With the United Arab Emirates hosting COP28, 2023 is a critical year for oil and gas companies and producer economies to develop and justify strong and credible narratives about the role they intend to play.

The two main scenarios examined in this report are the Announced Pledges Scenario (APS) and the Net Zero Emissions by 2050 (NZE) Scenario. These scenarios set out what transition pathways aligned with regional or global net zero targets would mean for oil and gas companies and producer economies. They both require a significant acceleration in the pace of change compared with today's trends, which are reflected in the Stated Policies Scenario (STEPS). The report includes metrics, based on our scenarios, that allow stakeholders to make informed decisions on whether producers are making genuine efforts to adapt business models at the necessary pace and scale.

This chapter discusses the outlook for oil and natural gas demand and supply in net zero transitions. Chapter 2 sets out the technology options for the oil and gas industry, including options to cut emissions from its own operations, and the clean energy technologies that appear best suited to its existing skills and resources. Chapter 3 sets out some of the strategic responses of oil and gas producers to date and explores what the industry would need to do to align with net zero transitions. And Chapter 4 focuses on producer economies, examining how they can adapt to a changing energy system and how producers and consumers can work together to achieve fair, net zero aligned transition pathways.

The remainder of this chapter is structured as follows: Section 1.2 provides an overview of the structure of the oil and gas industry, highlighting the contribution of different types of companies to supply and investment trends. Section 1.3 examines oil and gas demand in the APS and NZE Scenario, including the main levers used to reduce demand, and where oil and gas use is most resilient. Section 1.4 describes the oil and gas price trajectories and how production evolves by region in net zero transitions. Section 1.5 examines the implications for oil refining and oil and gas trade. Section 1.6 explores alternative supply pathways that could be possible with the same overall demand trajectory of the NZE Scenario, highlighting potential upsides and downsides and how different supply-side dynamics might play out in practice. Finally, Section 1.7 examines the implications for investment, including the risks posed by overinvestment or underinvestment in oil and gas during net zero transitions.

1.2 The oil and gas industry today

There are thousands of companies around the world that produce oil and gas today. The industry is characterised by a wide variety of corporate structures and governance models, ranging from small businesses to some of the world's largest industrial corporations. The top fifty companies produce around 70% of total supply. For this report, we distinguish between four main types of company:

- **Majors** are large companies listed on stock markets in the United States and Europe. They have historically focused on developing large, capital-intensive projects and their upstream divisions represent most of their financial value and revenue. In this report, this group comprises seven companies: BP, ConocoPhillips, Chevron, Eni, ExxonMobil, Shell, and TotalEnergies.
- **Independents** are smaller fully integrated companies or independent upstream operators. They encompass a wide range of companies, such as Lukoil, Repsol, OMV and Woodside, as well as many North American companies – including shale gas and tight oil players – such as Apache, Hess, Marathon Oil, Pioneer Natural Resources and Oxy, and diversified international conglomerates with upstream activities, such as Mitsubishi Corp.
- **National oil companies (NOCs)** have been given mandates by their home governments to exploit national resources and have a legally defined role in upstream development. While some NOCs operate outside their home country and are also active downstream, the bulk of their assets are based in their home country's upstream operations. Most of the largest NOCs are located in the Middle East, such as Saudi Aramco, National Iranian Oil Company, Kuwait Petroleum Corporation, Abu Dhabi National Oil Company and QatarEnergy. There are also NOCs in Eurasia, including in Russia, in Latin America and many parts of Africa and Asia (see Chapter 3 for further details).
- **International national oil companies (INOCs)** share similarities with NOCs in their ownership and governance, but have substantial upstream investments outside their home country. This is usually done in collaboration with host NOCs or private companies. Some INOCs are also major players in the global gas markets. They include Equinor, China National Petroleum Corporation, Gazprom, Petronas and India's Oil and Natural Gas Corporation.

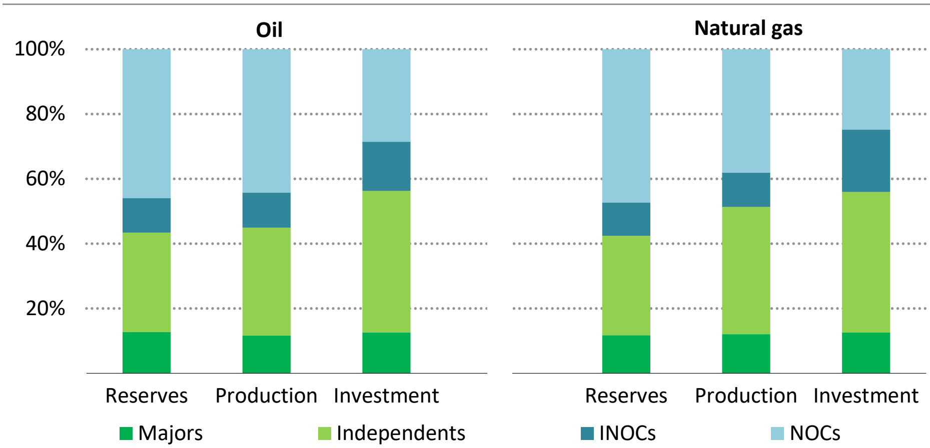
In addition to these categories, other types of company play a key role in the oil and gas industry. They include:

- Service companies that provide specialist engineering services for drilling, reservoir management, construction of infrastructure, and environmental impact management (e.g. SLB and Baker Hughes).
- Pure downstream companies that operate refinery and petrochemical sites (e.g. Marathon Petroleum, Phillips 66, Essar, Reliance and Valero).

- Trading companies whose business models tend to rely on owning only those physical assets that help optimise their position in the market (e.g. Vitol, Mercuria, Glencore and Gunvor).
- Midstream operators of pipeline systems (e.g. Enagas, Enbridge, TC Energy, Enterprise Products Partners and Kinder Morgan).
- Shipping companies operating tankers and LNG carriers (e.g. Maersk, Teekay, Euronav, Frontline and Mitsui).
- Storage companies that manage and lease tank capacity for crude and products (e.g. VTTI and OilTanking).
- Retail companies that buy product directly from refiners or from traders in the local or international market (e.g. Couche-Tard, Kroger and Avia).

Attention on the oil and gas industry often focuses on the role of the majors, but they own less than 13% of global oil and gas production and proved-plus-probable (2P) reserves (Figure 1.1). NOCs and INOCs account for more than half of global production and close to 60% of the world's oil and gas reserves. Their share of capital investment in upstream oil and gas projects is slightly lower, at around 45% of the global total. This is partly because they tend to own resources with lower-than-average development costs and partly because their assets tend to have slow decline rates, meaning lower levels of spending are required to maintain production.

Figure 1.1 ▹ Ownership of oil and gas reserves, production and upstream investment by company type, 2022



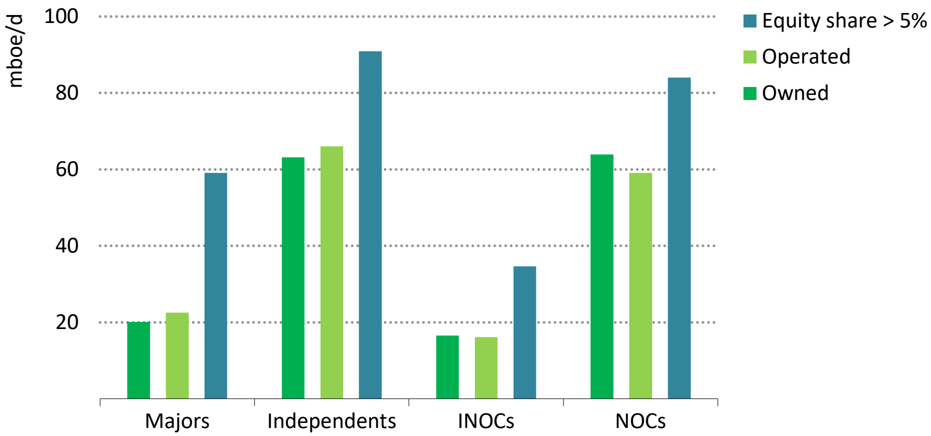
NOCs, including those with operations outside their home country, produce more than half of the world's oil and gas. The majors produce 13% of the total.

Note: INOCs = International national oil companies; NOCs = National oil companies.

Source: IEA analysis based on Rystad Energy.

Partnerships and joint ventures are prevalent across the oil and gas industry. Exploration and new field development are risky and complex processes, and companies often split the ownership of any discovery or development to spread the risk and reward and to encourage technical and operational collaboration. Joint ventures mean the financial engagement and influence of companies can spread further than the oil and gas assets that they directly operate. For example, of the oil and gas produced in 2022, the majors owned 20 million barrels of oil equivalent per day (mboe/d) and operated assets that produced 23 mboe/d; nearly three times as much oil and gas (60 mboe/d) was produced from assets in which they own more than 5% of production (Figure 1.2).

Figure 1.2 ▷ Oil and gas production in 2022 by ownership, operator, and from assets in which companies have an equity stake greater than 5%



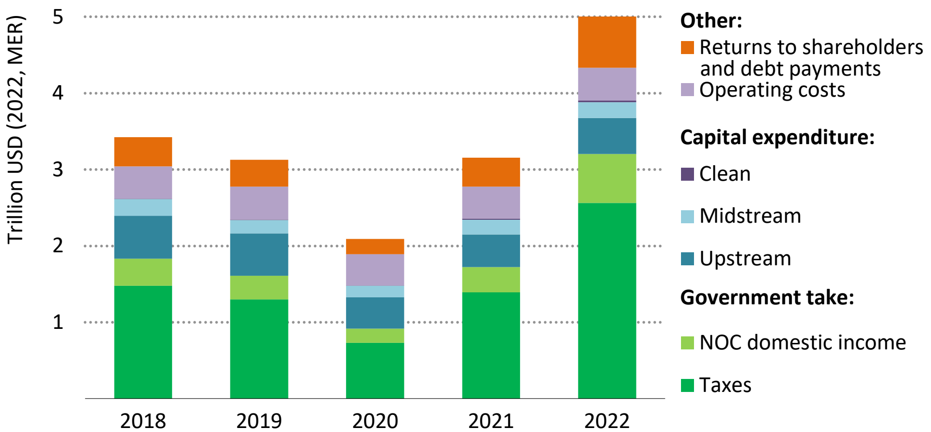
Companies' production includes oil and gas from both operated and non-operated assets, but the influence of companies can extend well beyond this.

Note: Equity share > 5% = total production from all assets in which a company holds at least a 5% share of the produced oil and gas.

Mergers and acquisitions are common in the oil and gas industry, with more than USD 200 billion worth of deals taking place annually on average between 2018 and 2022. These are used by companies to expand oil and gas production, diversify into new markets, acquire new technologies, benefit from economies of scale, and to increase clean energy holdings. The oil and gas industry spent around USD 15 billion acquiring clean energy ventures in 2022, around 10% of the total value of its mergers and acquisitions in that year. A number of major deals have also taken place in 2023, including the purchase of US shale independent Pioneer Resources by ExxonMobil for USD 60 billion and the purchase of Hess Corporation for USD 53 billion by Chevron.

The global oil and gas industry generated close to USD 3.5 trillion in revenue on average each year between 2018 and 2022 (Figure 1.3). This includes revenue from crude oil and natural gas production as well as the additional value created from processing, refining, transporting and marketing the final products to consumers. There is a high degree of year-on-year variation in this figure, ranging from a low of USD 2 trillion in 2020, given the impacts of the Covid-19 pandemic, to a historic record high of USD 5 trillion in 2022 during the global energy crisis.

Figure 1.3 ▷ Use of revenue by the oil and gas industry, 2018-2022



The oil and gas industry has generated around USD 17 trillion of revenue since 2018. Half was paid to governments and 40% was spent developing and operating oil and gas assets.

Note: NOC domestic income = National Oil Company income generated in their home country.

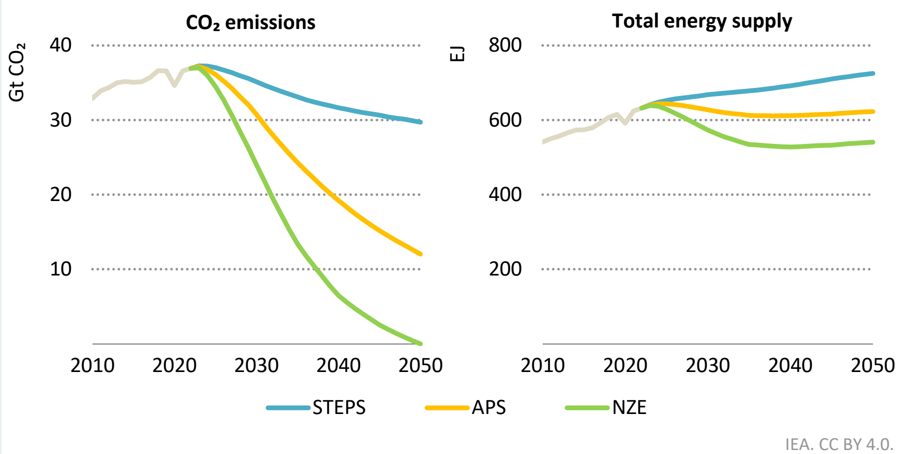
Around 50% of the revenue produced by the oil and gas industry since 2018 went to governments, either from royalties and taxes or from income generated by NOCs and INOCs in their home countries. A further 40% was capital and operating expenditure, and the remaining 10% was returned to shareholders through dividends and share buybacks or used to pay down debt.

Companies have responded to the prospect of net zero transitions with a range of strategies. The most common approaches are to reweight overall production towards natural gas, demand for which is perceived to be more durable through net zero transitions, and to take steps to reduce emissions from operations. Some companies have diversified their capital expenditure more substantially, moving into clean energy technology areas such as offshore wind, carbon capture, utilisation and storage (CCUS), low-emissions fuels, and electricity. Oil and gas companies with the largest proportions spent around 15-25% of their total capital budgets on clean energy in 2022 through mergers and acquisitions, joint ventures and direct investment. As a whole, the industry spent around USD 20 billion on clean energy, representing less than 3% of its total capital budget and around 1% of total clean energy investment globally. For the moment, the oil and gas industry remains a marginal force in directly building up a clean energy system (see Chapter 3).

Box 1.1 ▷ Scenarios examined in this report

Three scenarios provide a framework for the analysis in this report (Figure 1.4). These scenarios have been fully updated to reflect the latest economic and energy data and are described in detail in the *World Energy Outlook 2023* (IEA, 2023a). Rates of economic growth – 2.6% on average globally each year to 2050 – and population growth are the same across the scenarios. We focus our analysis mainly on the APS and the NZE Scenario, which achieve net zero transitions for the energy sector at different speeds.

Figure 1.4 ▷ Energy-related CO_2 emissions and total energy supply by scenario



Our scenarios paint very different pictures for the future of emissions and energy.

The **Stated Policies Scenario (STEPS)** looks at what governments are actually doing rather than what they say they will achieve. It is an outlook based on a detailed sector-by-sector review of energy and climate policies and measures currently in place or under development by governments. In this scenario, each of the fossil fuels has a peak in demand before 2030, but declines after these peaks are relatively muted. Annual CO_2 emissions are 20% below 2022 levels in 2050 and these trends are consistent with a temperature rise of around 2.4 °C in 2100 (with a 50% probability).

The **Announced Pledges Scenario (APS)** assumes that governments meet all of the climate-related commitments they have announced in full and on time. Pledges made by companies, businesses and industry organisations are also taken into account. Energy-related CO_2 emissions soon peak and they are around 70% lower than 2022 levels in 2050. There are also major reductions in all other energy-related greenhouse gas (GHG) emissions, including methane from fossil fuel operations. This pathway is consistent with a temperature rise of 1.7 °C in 2100 (with a 50% probability).

The **Net Zero Emissions by 2050 (NZE) Scenario** describes a pathway for the global energy sector to reach net zero CO_2 emissions by 2050 without offsets from land-use measures. Advanced economies reach net zero emissions earlier than emerging market and developing economies, and universal access to electricity and clean cooking is achieved by 2030. There are also efforts to cut down on methane and other GHG emissions. The global average surface temperature rise peaks at just below 1.6 °C around 2040 and then gradually falls to 1.4 °C in 2100 (with a 50% probability).

1.3 Demand

1.3.1 Oil

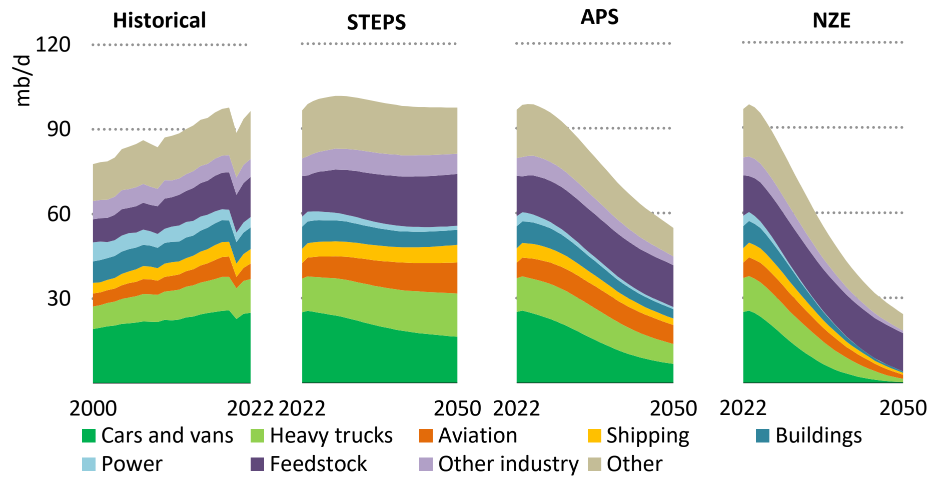
Global oil demand increased by just over 1 mb/d on average each year between 2010 and 2019. The Covid-19 pandemic caused a 9 mb/d drop in oil demand in 2020, the largest annual drop in history, but demand has since rebounded and it stood at 96.5 mb/d in 2022. Oil provides a large range of the energy service demands required by society, including, for example, about 25 trillion passenger kilometres in cars, 30 trillion tonne kilometres for trucks, 320 million tonnes of high-value chemicals, and many other outputs.

In the STEPS, oil demand reaches a maximum level of 102 mb/d in the late 2020s before declining to 97 mb/d in 2050. There are large declines in oil use in cars, buildings and power generation, although most of this is offset by growth in oil use in trucks, aviation and petrochemicals.

Net zero transitions require replacing existing uses of oil and gas and satisfying the growth in energy service demands in a low-emissions way. In the APS, oil demand soon peaks and declines to 93 mb/d in 2030 and 55 mb/d in 2050. In the NZE Scenario, demand falls to 77 mb/d in 2030 and 24 mb/d in 2050 (Figure 1.5).

Road transport. Almost half of global oil use is currently in road transport, but this is under increasing pressure from the rise of electric vehicles (EVs). The EV market has been growing exponentially in recent years, and nearly 20% of new cars being sold globally in 2023 are electric. In the APS, the share of electric car sales rises to nearly 45% in 2030 and 80% in 2050, reflecting electrification ambitions announced by governments, including a commitment by more than 40 governments to accelerate the transition to zero-emission cars and vans, as well as a major scale-up in EV manufacturing hubs around the world that encourages consumers to choose to buy a domestically manufactured EV over an internal combustion engine (ICE) car. Electric and hydrogen heavy truck sales grow from 1% today to just under 20% of total sales in 2030 and 60% in 2050.

Figure 1.5 ▷ Oil demand by scenario, 2000-2050



Road transport accounts for almost half of oil demand today and sees the largest changes to 2050. Oil use for petrochemicals is much more robust despite increases in recycling.

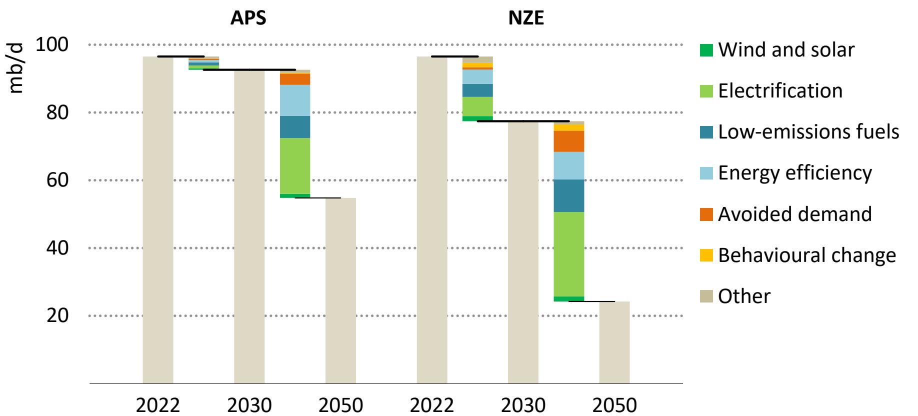
Notes: Other includes buses, 2/3 wheelers, agriculture, other energy sector, and other non-energy use.

In the NZE Scenario, virtually no new ICE cars are sold from 2035, and all new trucks use electricity or hydrogen from 2040 in advanced economies and China, and from 2045 in the rest of emerging market and developing economies. To 2030, 20% of the overall reduction in oil demand comes from electrifying road transport (Figure 1.6). A further 5% of the reduction comes from behavioural change measures in road transport, including through improvements to public transport coverage and quality, and encouraging walking and cycling, car sharing and carpooling. By 2050, 1.5 billion of the 1.6 billion cars on the road are electric, and 140 million out of 180 million heavy-duty trucks and buses on the road are electric.

Aviation. Around 5 mb/d of oil was used in domestic and international aviation in 2022, a substantial increase from levels in 2021, but still far below the levels seen before the Covid-19 pandemic. Low-emissions fuels – including liquid biofuels and low-emissions hydrogen-based liquids – comprise less than 0.01% of the fuel used in aviation today. In the APS this share grows to 5% in 2030 and to over 35% in 2050, driven by government ambitions in the United States, the European Union, the United Kingdom and Japan, alongside industry initiatives. In the NZE Scenario, low-emissions fuels provide around three-quarters of fuel use in 2050. Behavioural changes – stemming from greater use of high-speed rail, fewer business flights, and frequent flyer levies – avoid 0.6 mb/d of oil demand in aviation in 2050 in the NZE Scenario.

Shipping. Around 5 mb/d of oil is consumed by ships annually, with a very small share of overall fuel use from low-emissions fuels (0.2% as biodiesel). In the APS this share grows to over 50% in 2050, mainly as a result of efforts to achieve the target set by the International Maritime Organization (IMO) to reduce emissions from maritime transport by at least half by 2050.[1] In the NZE Scenario, increases are even larger and 85% of the fuel used by the world's shipping fleet in 2050 comprises low-emissions fuels, predominantly hydrogen and hydrogen-based fuels.

Figure 1.6 ▷ Reductions in oil demand in the APS and NZE Scenario



The electrification of cars and trucks makes the largest contribution to reducing oil use, with efficiency improvements and low-emissions fuels also playing an important role.

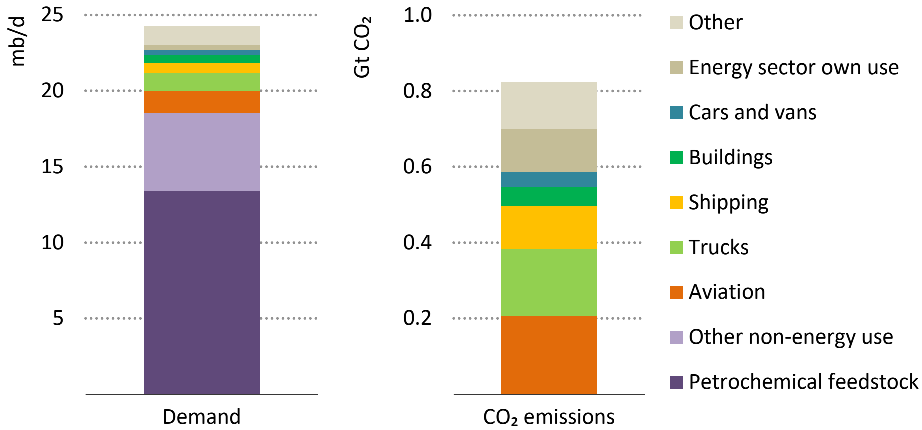
Notes: Avoided demand = material efficiency, reductions in oil use in refineries from lower demand, and other structural and economic effects. Other = hydropower, geothermal, nuclear, district heating, and natural gas.

Petrochemical feedstocks. Around 14 mb/d of oil was used as a feedstock in 2022, mainly to produce plastics. Demand for virgin plastics is set to grow rapidly, even though a number of policies to ban or reduce single-use plastics, improve recycling rates and promote alternative feedstocks have been announced. In the APS, these policies increase the global average collection rates for plastic waste from 16% today to 37% in 2050; despite this increase, oil use as feedstock still increases by 0.6 mb/d to 2030 and then only declines slightly to 2050. The use of alternative feedstocks, including bio-based feedstock, remains a niche industry due to a considerable cost gap and competing demand with other sectors. In the NZE Scenario, the global average plastics collection rate increases to 50% in 2050 and, combined with an increase in the use of alternative feedstocks, this means oil use as a petrochemical feedstock peaks in the mid-2030s and declines to around 13.5 mb/d in 2050.

[1] In July 2023 the IMO adopted a revised version of its GHG emissions strategy that looks to achieve net zero emissions from international shipping by 2050. Enforcement mechanisms are yet to be decided and so this is not included in the APS.

Efficiency improvements also play a role in all end uses to reduce oil demand. In the NZE Scenario, oil use in buildings is eliminated by electrification of heating and cooking appliances, even as liquefied petroleum gas (LPG) is used as an intermediary solution to provide full access to clean cooking; oil demand to produce power is replaced with solar and wind generation.

Figure 1.7 ▷ Oil demand and CO_2 emissions from oil use in the NZE Scenario, 2050



Three-quarters of the oil used in 2050 is in sectors where it is not combusted. Around 0.8 Gt CO_2 is emitted from oil use in 2050, mainly from aviation and trucks.

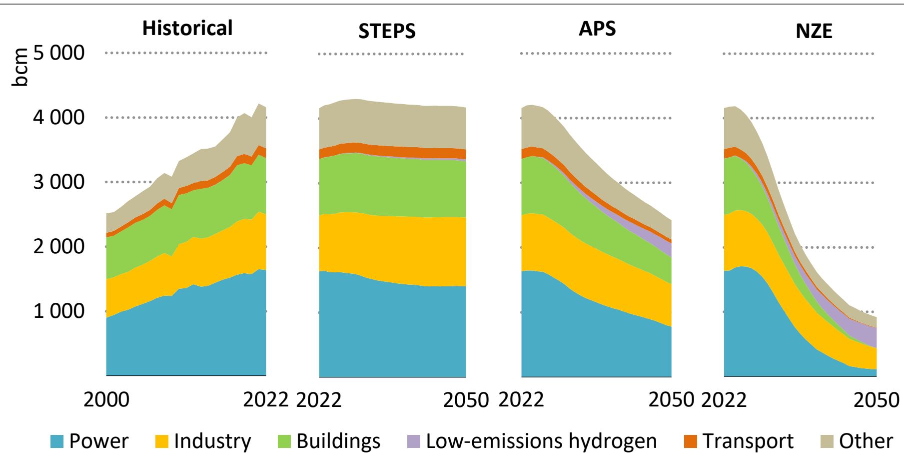
Note: Other non-energy use includes products not used in energy applications such as paraffin waxes, asphalt and bitumen.

Oil demand of 24 mb/d remains in 2050 in the NZE Scenario, one-quarter of the 2022 level. Three-quarters of this is used in sectors where the oil is not combusted, including as a petrochemical feedstock, and in products such as paraffin waxes, asphalt and bitumen (Figure 1.7). The remainder is combusted and this results in around 0.8 Gt CO_2 emissions in 2050. This is mainly in the remaining diesel trucks on the road and from aviation, which are each responsible for around 200 Mt CO_2 in 2050, as well as from shipping at 110 Mt CO_2. These residual emissions are offset from within the energy sector through the use of direct air capture with CCUS (DACS) and bioenergy with CCUS (BECCS).

1.3.2 Natural gas

Natural gas markets were upended by Russia's invasion of Ukraine. The sharp reduction in pipeline supply to Europe tightened global gas markets, resulting in record high prices and a drop in global demand of around 1% in 2022. Europe registered a record 13% fall in natural gas demand. Aggregate demand in emerging markets in Asia, the past engine of global gas demand growth, fell for the first time ever, as the spikes in global prices shook confidence in gas as an affordable alternative to coal or oil. Prices have moderated in 2023 and are expected to come under downward pressure in the second half of the 2020s as a large new wave of LNG export facilities starts operation. There is still significant scope for demand growth this decade, notably in industry, despite the near-term risks brought about by the supply squeeze. Nonetheless, increasingly cost-competitive low-emissions options for power generation and heating – alongside increased climate ambitions among many emerging market and developing economies in Asia – raise major questions about the long-term outlook for natural gas demand.

Figure 1.8 ▷ Natural gas demand by scenario, 2000-2050



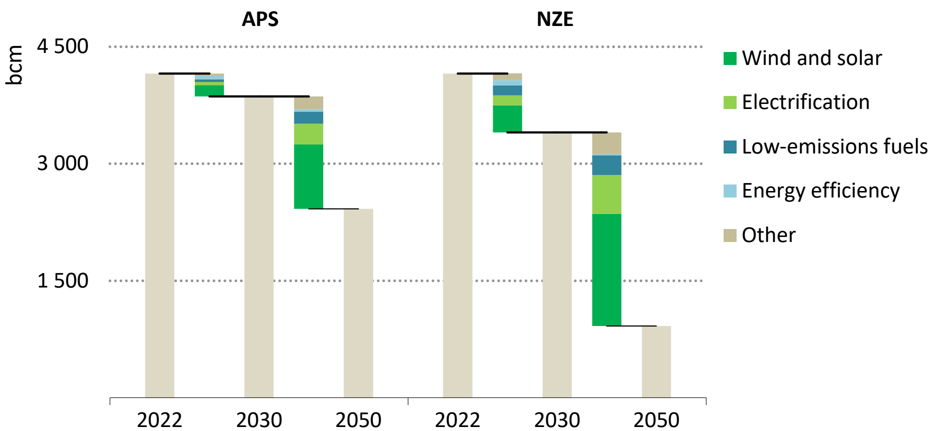
Gas demand declines steadily in the APS, with the largest reductions being in buildings and power. In the NZE Scenario there is little to no room for gas to act as a transition fuel.

Global natural gas demand in 2022 was around 4 150 bcm, 40% of which was consumed in the power sector, and around 20% in each of buildings and industry. In the STEPS, natural gas demand growth to 2030 is considerably lower than the 2.2% seen on average between 2010 and 2021. Demand peaks before 2030, after which moderate growth in some emerging market and developing economies is offset by declines in advanced economies, resulting in relatively stable demand globally between 2030 and 2050.

In the APS, global natural gas demand soon peaks and by 2030 is nearly 10% lower than in 2022 (Figure 1.8). A modest net increase in demand in emerging market and developing economies between 2022 and 2030 is more than offset by reductions in advanced economies, where gas is gradually replaced by renewables and offset by efficiency gains, notably in the buildings sector. In the NZE Scenario, natural gas falls rapidly in all sectors and demand is 20% lower in 2030 than in 2022. There are several factors that contribute to a reduction in natural gas demand over time:

Renewables. Annual wind and solar capacity additions reach 500 gigawatts (GW) by 2030 in the STEPS, 900 GW in the APS and 1 150 GW in the NZE Scenario. Each gigawatt of installed renewable capacity can displace anywhere in the range of 200-800 million cubic metres (m^3) of natural gas in the power sector. The installed capacity of gas-fired power plants falls less quickly than overall generation because some capacity is either added or retained for flexibility purposes in both the APS and NZE Scenario. Leaving gas plants on the system is often necessary to support a renewables-rich grid, especially to manage seasonal variations in demand; this requires an appropriate market design to remunerate balancing services.

Figure 1.9 ▷ Reductions in natural gas demand in the APS and NZE Scenario



Wind and solar play essential roles in reducing natural gas demand in the power sector. A wide range of other fuels and technologies are needed to reduce gas use in other sectors.

Note: Other = nuclear and other renewables.

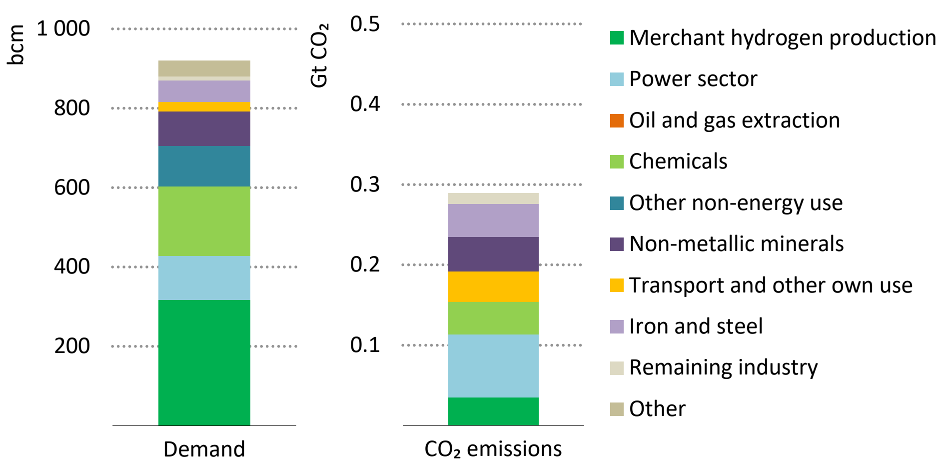
Bioenergy. Around 30 bcm of natural gas is replaced by the use of biomethane in 2050 in the STEPS, compared with 75 bcm in the APS and 110 bcm in the NZE Scenario, primarily to serve remaining energy service demands met by gaseous fuels in buildings. Biomethane is sourced from organic wastes, residues and other feedstocks that do not compete with food or have harmful effects on biodiversity. Large volumes of natural gas are also displaced by modern solid bioenergy in industry, buildings and for power generation.

Electrification. Around 140 bcm of natural gas is displaced through end-use electrification by 2050 in the STEPS, 300 bcm in the APS and 600 bcm in the NZE Scenario (Figure 1.9). Of the total in the NZE Scenario, around 50% is displaced by the use of electric motors in place of gas turbines in industrial facilities that require low-temperature heat, and another 40% is displaced by heat pumps in households, commercial buildings and small-scale industry. Electricity use for cooking and hot water – along with the use of modern bioenergy – enables households to eliminate natural gas use by 2050 in the NZE Scenario. EVs also replace most compressed natural gas vehicles on the road, reducing the need for around 60 bcm of natural gas in the NZE Scenario in 2050.

Other efficiency measures. Improvements in the energy efficiency performance of buildings helps to reduce gas use. Around 1.5% of buildings are currently being retrofitted to the highest performance standards each year in advanced economies; this rises to nearly 2% by 2030 in the APS and 2.5% in the NZE Scenario. More efficient gas-fired power plants are employed in both the APS and NZE Scenario, which also help to avoid some gas use.

There is 920 bcm of natural gas use remaining in 2050 in the NZE Scenario, around one-quarter of the level today (Figure 1.10). Natural gas is completely phased out in buildings, and its role in power generation is confined to dispatchable balancing; this requires around 100 bcm per year, or 95% less than the total amount of gas used in the power sector today. Around 60% of natural gas in 2050 is consumed in facilities equipped with CCUS. This includes 330 bcm of natural gas combined with CCUS to produce low-emissions hydrogen, 110 bcm used with CCUS in energy-intensive processes such as the production of cement, steel and primary chemicals, and 75 bcm used with CCUS in the power sector. A further 180 bcm is used as a feedstock or for other non-combustion purposes. Overall, average combustion emissions from natural gas fall from 1.8 kg CO_2/m^3 today to 0.3 kg CO_2/m^3 by 2050.

Figure 1.10 ▷ Remaining natural gas demand in 2050 in the NZE Scenario, 2050



Around 920 bcm of natural gas demand remains in the NZE Scenario in 2050, 75% lower than in 2022. The emissions intensity of this gas drops by 85%.

Note: The use of natural gas to produce on-site hydrogen is included in chemicals and iron and steel.

1.4 Supply

1.4.1 Prices

In our scenarios, oil and natural gas prices act as intermediaries between supply and demand to ensure that sources of supply meet changes in demand and hold the system in equilibrium. This balancing act means prices in our scenarios follow a relatively smooth trajectory; we do not attempt to anticipate the fluctuations or price cycles that characterise commodity markets. In practice, the potential for oil and gas price volatility is ever present, especially considering the profound changes that are needed in today's energy system to meet the world's climate goals.

In the APS, the policy focus on curbing oil and gas demand brings the prices at which the market finds equilibrium down from the levels in 2022: the international oil price falls to around USD 60/barrel in 2050 while gas prices in key importing regions remain in a band around USD 5-6 per million British thermal units (MBtu) (Table 1.1).

In the NZE Scenario, oil and gas prices quickly fall to the operating costs of the marginal project required to meet falling demand, and in 2050 they are around USD 25/barrel for oil and USD 2-5/MBtu for natural gas. These prices cover the operating expenses to lift oil and gas out of the ground of the marginal producer, the capital expenditure and operating costs of the required emissions reduction technologies, and upstream taxes.

Table 1.1 ⊳ Oil and natural gas prices by scenario

			STEPS		APS		NZE scenario	
Real terms (USD 2022)	**2010**	**2022**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
IEA crude oil (USD/barrel)	103	98	85	83	74	60	42	25
Natural gas (USD/MBtu)								
United States	5.8	5.1	4.0	4.3	3.2	2.2	2.4	2.0
European Union	9.9	32.3	6.9	7.1	6.5	5.4	4.3	4.1
China	8.8	13.7	8.4	7.7	7.8	6.3	5.9	5.3
Japan	14.6	15.9	9.4	7.8	8.3	6.3	5.5	5.3

Other price trajectories are possible, even while maintaining the overall demand trajectories in the APS and NZE Scenario. For example, moves on the part of producer economies with the lowest production costs to gain market share even as demand declines would likely lead to lower prices, at least for an initial period (see Section 1.6). Lower prices could also occur in the case of overinvestment in oil and gas supply. In this case, projects would face even larger commercial risks, producer economies would face further headwinds, and it would risk pushing the 1.5 °C goal out of reach (see Section 1.7).

Higher price trajectories could occur if there are widespread efforts by large producers to restrict production. For example, in the NZE Scenario, the oil market share of the Organization of the Petroleum Exporting Countries (OPEC) rises from 36% in 2022 to 53% in

2050. Production cuts could lead to large prices increases, especially as demand in the APS and NZE Scenario becomes increasingly concentrated in sectors with few alternatives (e.g. the aviation and petrochemical sectors). However, in the NZE Scenario, low prices and demand mean around 7 mb/d worth of projects would need to close by 2040 before the end of their technical lifetimes. Any efforts to drive up prices by restricting supply would likely mean this overhang stays on the market for longer, muting the overall magnitude of the price rise.

Another possibility that could lead to higher and more volatile prices is if some large producers struggle to withstand the strains placed on their fiscal balances from lower oil and gas income. This could have knock-on impacts for upstream operations and mean that oil and gas supply falls faster than demand. Venezuela provides a cautionary tale for how quickly oil production can fall if there are problems with resource management; production fell by 16% per year on average between 2015 and 2020, around three times faster than the average decline in demand in the NZE Scenario.

Higher prices and increased price volatility could also result if investor pressure or government policies lead to widespread shut-ins of existing production, or they prematurely close off investment in oil and gas supply and companies cannot maintain capital spending on existing assets. In general, however, impacts would be moderated by continued declines in demand and by supply responses by other producers.

1.4.2 Oil supply

Conventional crude oil production peaked in the late 2000s just below 70 mb/d and is currently around 63 mb/d (65% of global oil production). If no new conventional crude projects were to start operations and there were to be no capital expenditure on any current sources of supply, we estimate that production would fall by around 8-9% every year (this is known as the "natural" decline rate). In practice, companies do invest in their current sources of supply and this slows the annual decline rate to around 4-5% (this is known as the "observed" decline rate). Under this condition, existing sources of conventional crude oil supply will decline to around 45 mb/d in 2030 and 20 mb/d in 2050 as existing fields mature and projects reach the end of their lives.

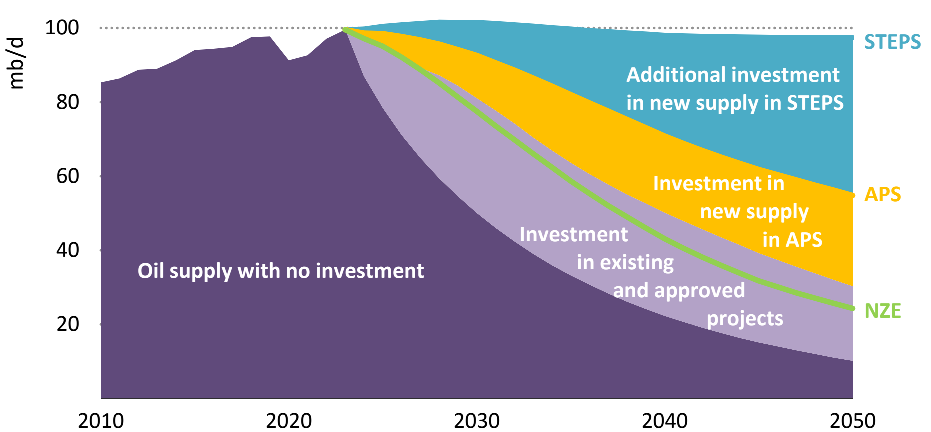
Offsetting some of this decline is production from new conventional crude oil projects that were recently approved for development. These projects come on line in the next few years and add close to 10 mb/d of oil production in 2030 (including 2.5 mb/d from projects that have been, or will be, approved in 2023). This means that production from existing and approved conventional crude oil projects declines by around 2% on average to 2030 and, once production from these approved projects peaks and starts to decline, by close to 5% each year on average from 2030 to 2050.

Other sources of supply make a major contribution to the oil supply balance today, but exhibit very different production dynamics from conventional crude oil fields:

- Natural gas liquids: 19 mb/d was produced in 2022 (20% of global oil production). These play an important role in the economics of gas field development by providing an additional revenue stream; their production is often governed by gas market dynamics.
- Tight oil: just over 8 mb/d was produced in 2022, 95% of which was from the United States. Tight oil wells decline by around 60-70% within 12 months of first production (compared with a decline of around 6% for a conventional oil well). Decline rates at an aggregate level are therefore mostly driven by levels of investment and scheduled drilling.
- Extra-heavy oil and bitumen (EHOB): just under 4 mb/d was produced in 2022, 95% of which was from Canada. Like tight oil, resources are spread over a large geographical area and new wells need to be drilled, or mines extended, to maintain production. For EHOB, the investment required for these wells is only a fraction of the initial upfront investment for a project as a whole and so natural decline rates are generally assumed to be low.

In the STEPS, although demand peaks before 2030, the annual average rate of decline thereafter is less than 0.2% to 2050 and investment in all types of production is required to ensure that there are no shortfalls in supply (Figure 1.11).

Figure 1.11 ⊳ Oil supply by scenario, 2010-2050



New conventional oil projects are needed in the APS, but no new projects are approved for development in the NZE Scenario and higher-cost projects are also closed from the 2030s.

In the APS, oil demand falls by 0.5% each year on average to 2030 and by around 2.5% each year between 2030 and 2050. In aggregate, no further hydrocarbon exploration is needed to meet these demand levels, although new conventional oil discoveries may in some cases be produced at a lower cost than existing sources of production. New conventional crude oil projects are developed and small-scale extensions of existing EHOB projects offset some of the underlying declines, as does continued drilling for tight oil (Table 1.2).

Table 1.2 ⊳ Global liquids and oil production by scenario (mb/d)

			STEPS		APS		NZE	
	2010	2022	2030	2050	2030	2050	2030	2050
World liquids supply	**86.5**	**99.2**	**104.5**	**102.1**	**97.5**	**65.4**	**83.7**	**35.7**
World oil supply	**85.3**	**97.1**	**101.5**	**97.4**	**92.5**	**54.8**	**77.5**	**24.3**
World processing gains	2.2	2.3	2.4	2.9	2.4	1.6	2.3	0.7
World oil production	**83.1**	**94.8**	**99.1**	**94.5**	**90.2**	**53.1**	**75.1**	**23.5**
Conventional crude oil	67.4	62.8	61.3	58.2	54.9	29.8	48.0	15.8
Onshore	44.6	41.3	39.9	38.4	35.6	18.5	31.6	10.5
Offshore	22.8	21.6	21.4	19.8	19.3	11.4	16.3	5.3
Tight oil	0.7	8.3	11.1	10.2	10.3	6.9	7.6	1.8
Natural gas liquids	12.7	19.0	21.2	19.4	20.1	13.6	16.2	4.4
EHOB	2.0	3.7	4.4	5.5	3.9	2.5	3.0	1.5
Other production	0.5	0.9	1.0	1.2	0.9	0.3	0.3	0.0
OPEC share	*40%*	*36%*	*35%*	*43%*	*35%*	*45%*	*37%*	*53%*
Liquid biofuels	1.2	2.2	3.0	4.5	4.8	7.0	5.6	5.4
Low-emissions hydrogen-based fuels	0.0	0.0	0.0	0.2	0.2	3.6	0.7	6.0

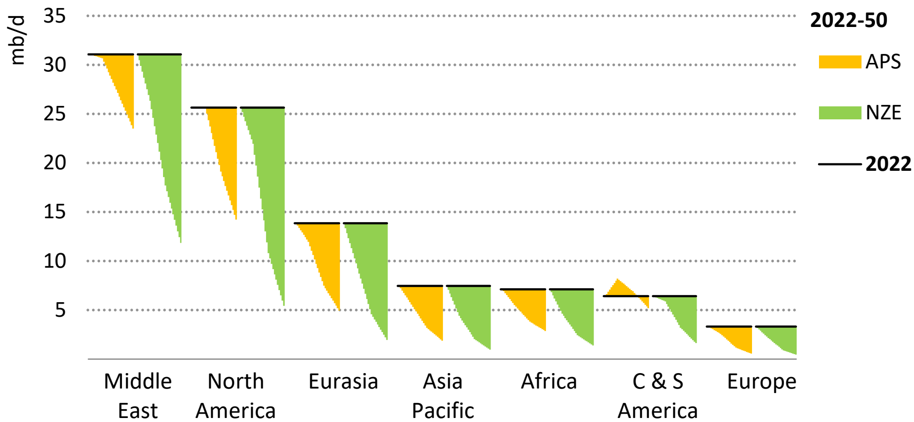
Note: OPEC = Organization of the Petroleum Exporting Countries. Liquid biofuels and low-emissions hydrogen-based liquid fuels are expressed in energy equivalent volumes of gasoline and diesel, reported in million barrels of oil equivalent per day.

In the NZE Scenario, oil demand declines by around 2.5% on average to 2030. This pace of decline is sufficiently strong that no new long lead time upstream conventional projects need to be approved for development.[2] There is some ongoing investment in tight oil and EHOB production to avoid these declining very rapidly, but no new infrastructure is required for either source and both see steady declines in output over time. In total, production falls across all regions to 2030 (Figure 1.12). After 2030, demand falls by more than 5.5% each year on average. This rate of decline is sufficiently fast that a number of higher-cost fields are closed before they reach the end of their technical lifetimes. In 2040, for example, more than 7 mb/d of oil production is closed earlier than would be implied by observed declines.

Investment in existing oilfields in the NZE Scenario ensures that supply does not fall faster than the decline in demand. For conventional oil, this is similar to the types of field extensions carried out in the past that slow the natural decline rate to the observed decline rate. It includes, for example, the use of infill drilling and improved management of reservoirs, as well as some enhanced oil recovery. Investment is also needed to minimise the emissions intensity of operations. The NZE Scenario sees a 50% reduction in the global average GHG emissions intensity of oil and gas production between 2022 and 2030, and close to zero emissions from oil and gas operations soon after 2040 (see Chapter 2).

[2] A discussion on the lead time of projects is included in Chapter 7 of *World Energy Outlook 2022* (IEA, 2022).

Figure 1.12 ▷ Oil production by region in the APS and NZE Scenario



Production declines to 2030 across all regions in net zero transitions, with supply increasingly concentrated in large resource holders given their lower decline rates.

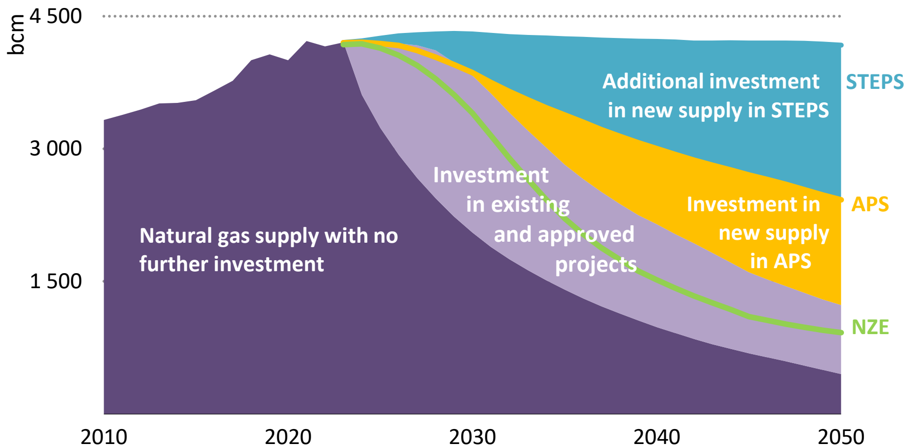
Note: C & S America = Central and South America.

1.4.3 Natural gas supply

Russia's invasion of Ukraine and its subsequent cuts to pipeline gas supply created a scramble among importers, notably in Europe, to secure alternative sources of supply. Upstream spending on gas outside Russia increased by more than 15% in 2022 and more than 150 bcm of new supply will come online by the late 2020s from projects approved for development since the invasion – greater than the 100 bcm drop in Russian production in 2022. Although the near-term balance remains tight, this wave of new supply project announcements – notably for LNG – has eased fears of a supply deficit in the years ahead. But it also raises the risk of significant oversupply, especially if the world redoubles its commitment to a net zero pathway.

Production dynamics for natural gas are broadly similar to those for oil. Conventional non-associated natural gas fields supply around 60% of current global gas demand and observed decline rates are around 4-5% per year on average. Gas volumes that are produced as a by-product of oil production (associated gas) make up around 10% of total global gas production today, and their supply dynamics are closely tied to the pace of reduction in oilfields. Unconventional gas – which comprises shale gas, tight gas and coal bed methane – provides the remaining 30% of gas supply today. Shale and tight gas exhibit similar properties to tight oil and would decline rapidly if drilling were to stop. Decline rates for coal bed methane projects are more comparable to conventional gas.

Figure 1.13 ⊳ Natural gas supply by scenario, 2010-2050



In the NZE Scenario, no new long-lead time gas projects are required and some production capacity is surplus to demand. In the APS, 1 200 bcm of new production is required in 2050.

In the STEPS, new sources of gas supply are essential to meet demand and offset declines in existing sources of supply. Just over 400 bcm of new upstream supply comes online over the period to 2030. After 2030 demand remains broadly stable, but new projects are still needed to ensure a smooth balance between supply and demand at a regional level and around 2 900 bcm of new supply is required by 2050 (Figure 1.13).

Table 1.3 ⊳ Global production of gases and natural gas trade

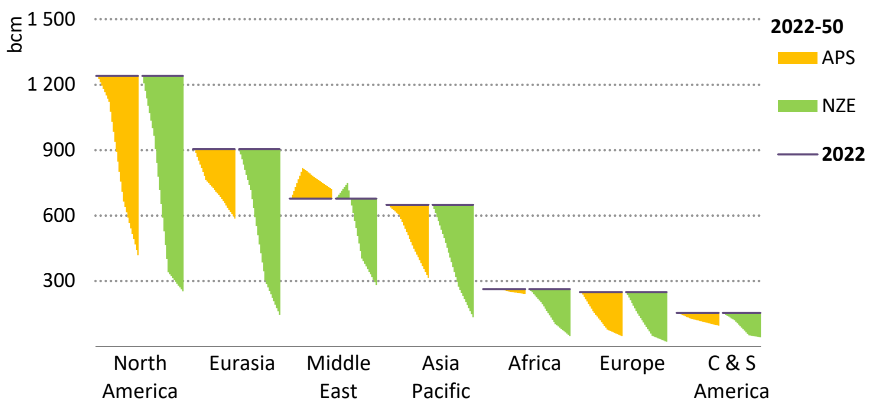
			STEPS		APS		NZE	
	2010	2022	2030	2050	2030	2050	2030	2050
Natural gas production (bcm)	**3 274**	**4 138**	**4 299**	**4 173**	**3 861**	**2 422**	**3 403**	**919**
Conventional gas	2 769	2 871	2 894	3 016	2 742	1 940	2 363	627
Unconventional gas	504	1 266	1 405	1 157	1 119	482	1 040	293
Natural gas net trade (bcm)	**640**	**810**	**919**	**921**	**827**	**370**	**719**	**187**
LNG	276	479	611	656	588	242	507	121
Pipeline	364	331	309	265	246	125	220	47
Low-emissions gases (bcme)	**23**	**39**	**89**	**324**	**197**	**1 161**	**414**	**1 797**
Low-emissions hydrogen	0	2	23	99	80	809	232	1 385
Biogas	23	28	42	89	51	117	56	129
Biomethane	1	9	24	136	66	235	126	283

Note: bcme = billion cubic metres of natural gas equivalent.

In the APS, demand declines by around 1% each year on average to 2030 and by around 2.5% each year from 2030 to 2050 (Table 1.3). Meeting this level of demand requires around 1 200 bcm of supply from new projects in 2050, which in aggregate can be met without any further natural gas exploration. In the NZE Scenario, natural gas demand falls on average by 2.5% per year between 2022 and 2030. This could be met in aggregate without any new long lead time upstream conventional projects, but some projects that have already been approved help ensure gas demand can be met at the country and regional level, taking into account the availability of import and export infrastructure (Figure 1.14). Some investment also continues in unconventional gas; for example, around 500 shale gas wells are drilled in 2030 in the United States (compared with around 2 500 wells that were drilled in 2022). Extensive efforts are also made to stop flaring and methane emissions, which unlock more than 100 bcm of additional annual supply globally in 2030.

Between 2030 and 2040, demand in the NZE Scenario declines by around 7.5% per year, a rate faster than implied by aggregate declines in existing sources of production. Around 650 bcm of production capacity would be surplus to demand requirements in 2040 at the global level and some higher-cost projects would close before reaching the end of their technical lifetimes. After 2040, the surplus production falls to 400 bcm as demand reductions slow to around 5% on average per year, a consequence of ramping up the use of natural gas for hydrogen production.

Figure 1.14 ⊳ Natural gas production by region in the APS and NZE Scenario



In the APS, the sharpest drops in production occur in North America and Eurasia, while the Middle East remains resilient. Production declines in all regions under the NZE Scenario.

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

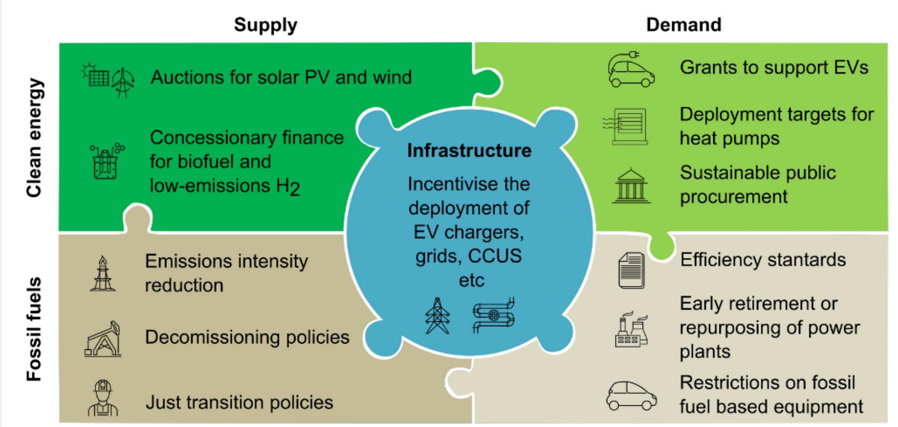
LNG trade declines more slowly than overall natural gas demand in NZE Scenario. This means that gas production on average falls slightly less quickly in LNG-exporting regions than in LNG-importing regions. This is also a consequence of larger fields declining more slowly. Among exporting regions, North America records the largest fall in natural gas production in absolute terms in the NZE Scenario, whereas Eurasia falls the most in percentage terms.

Box 1.2 ▷ Demand- and supply-side policies in net zero transitions

There is sometimes a debate around whether demand or supply should take the lead if the world is to successfully achieve net zero transitions. This distinction is unhelpful and risks postponing – perhaps indefinitely – the changes that are needed. Focusing narrowly on a "demand-led transition" implicitly leaves responsibility for change with consumers, and legitimises a passive approach from suppliers. Meanwhile, the idea of a "supply led transition" comes with a heightened risk of price spikes and volatility. In practice, no one committed to change can wait for someone else to move first: successful net zero transitions will depend on suppliers and consumers working together, with all parties implementing supportive policies and regulations.

In the APS and NZE Scenario, this means that a wide range of different policies are introduced to scale up both the demand and supply of clean energy and to reduce the demand and supply of fossil fuels and emissions in an equitable manner (Figure 1.15).

Figure 1.15 ▷ Examples of policies to scale up demand and supply of clean energy and reduce the demand and supply of fossil fuels



IEA. CC BY 4.0.

Successful net zero transitions require policies on the supply and demand of fossil fuels and clean energy, with suppliers working together with consumers to reduce emissions

Policies that boost the demand for clean energy include grants to encourage consumers to purchase an EV, or deployment targets for heat pump installations. Policies to help scale up new sources of clean energy supply include competitive auctions for solar PV and wind, and providing concessionary finance for biofuel and low-emissions hydrogen production projects.

These actions need to be coordinated among governments, major consumers and large energy suppliers to ensure the well-synchronised development of new clean energy value chains. For example, new low-emissions shipping fuels such as methanol or ammonia, along with associated bunkering infrastructure, needs to be available to fuel a burgeoning orderbook of vessels that are capable to run on these fuels.

Policies reducing fossil fuel demand play a role in creating additional room for clean energy alternatives to expand. This includes, for example, policies to facilitate the early retirement or repurposing of coal-fired power plants along the lines of the Just Energy Transition Partnerships with South Africa, Indonesia and Viet Nam. These need to include adequate provision for the social impacts on affected workers and communities. In addition, in the NZE Scenario, sales of coal and oil boilers come to an end from 2025, and no new ICE cars are sold after 2035.

Fossil fuel supply-focused policies help to ensure more secure and equitable energy transitions. This includes policies to reduce the emissions intensity of oil and gas supply, and help exporters achieve economic diversification and better manage the sharp reductions in fiscal income from oil and gas sales (Chapter 4). In addition, policy makers need to work with industry to plan for the safe and responsible decommissioning of wells or pipelines when they are no longer needed, otherwise this could lead to major additional costs and environmental impacts. In the APS and NZE Scenario, there are no explicit policies restricting resource extraction or centralised efforts to impose production quotas as the drops in oil and gas demand are assumed to be incorporated fully into the resource development plans of companies and countries.

Efforts to reduce fossil fuel use and scale up clean energy need to be carefully designed, anticipating possible feedback effects and interdependencies to avoid creating new vulnerabilities. The unplanned, chaotic or premature retirement of some existing fossil fuel infrastructure could have negative consequences for the reliability of the overall system; for example, if gas-fired power plants are rendered uneconomic even while they continue to provide valuable electricity system services. Bans on ICE vehicles or fossil fuel boilers would only be effective if clean energy alternatives are available. Policy makers would also need to consider the extent to which existing fossil fuel infrastructure, such as gas pipelines or storage sites, could be repurposed to transport low-emissions gases.

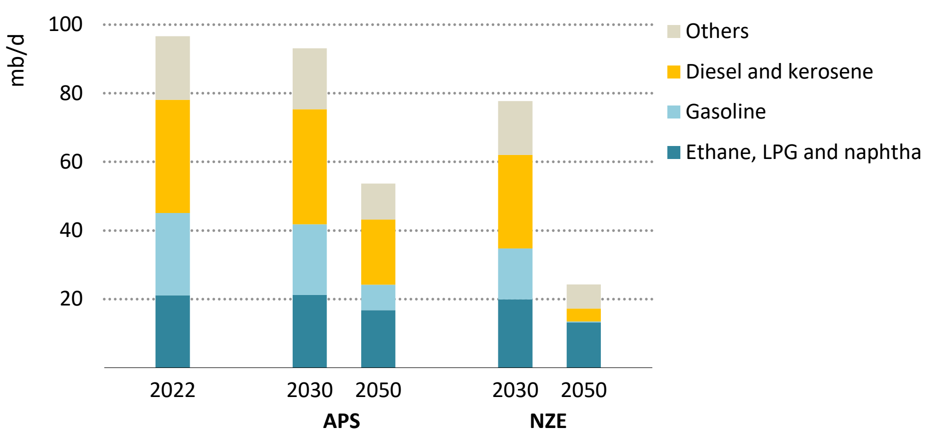
1.5 Refining and trade

1.5.1 Refining

The refining industry has enjoyed favourable profits in recent years as the post-pandemic recovery in demand coincided with the first net reduction in capacity in 30 years. However, today's high margins may not provide a good indication of the industry's future as it faces multiple challenges from net zero transitions. In all scenarios, the unbroken pace of demand growth seen over the past decades changes direction. Oil demand reaches a peak in the 2020s and enters structural decline. This shift in demand trajectory creates a growing mismatch between refining capacity and oil product demand, putting pressure on refineries that are older and less competitive. The growing production of biofuels and the supply from natural gas liquids further exacerbate this pressure as they reduce the scope for refineries to serve liquid demand.

These challenges are compounded by changing patterns of product demand. Transport fuels such as gasoline, diesel and kerosene have been the main driver of demand growth over the past few decades. However, they account for the bulk of demand reductions in the coming decades. The decline in gasoline demand is particularly notable, with its share of oil product demand falling from 25% today to around 15% by 2050 in the STEPS and APS, and to nearly zero in the NZE Scenario. Demand for diesel and kerosene fares slightly better, maintaining their share of total demand in the STEPS and APS. But they experience a significant decline in the NZE Scenario as the long-distance transport and aviation sectors decarbonise. Demand for petrochemical feedstock (ethane, LPG and naphtha) by comparison remains relatively resilient. In the NZE Scenario their share of total product demand reaches over 50% by 2050, up from 22% today, necessitating strategic adjustments by the refining industry to align with future market demands (Figure 1.16). One example of the strategic response by refiners to date is to integrate refineries with petrochemicals to secure long-term competitiveness (see Section 4.4.4).

Figure 1.16 ⊳ Oil product demand in the APS and NZE Scenario



Reductions in oil demand are accompanied by a major shift in product demand towards petrochemical feedstock.

Note: LPG = liquefied petroleum gas.

After the recent short-lived reduction in capacity, the industry is on track to add a host of new refineries despite a notable slowdown in demand growth. Over 6 mb/d of crude distillation capacity is slated to come online in the coming years, mostly in developing economies in Asia and the Middle East (IEA, 2023b). This wave of capacity expansions is expected to be the last surge of new additions, with limited capacity growth projected after 2030 across all scenarios.

Table 1.4 ⊳ Global refining capacity and runs by scenario (mb/d)

		STEPS		APS		NZE	
	2022	2030	2050	2030	2050	2030	2050
Refining capacity	**102.7**	**105.2**	**105.8**	**99.4**	**62.9**	**87.5**	**29.2**
Atlantic Basin	54.2	53.2	51.8	50.4	28.3	44.0	13.2
East of Suez	48.5	52.0	54.0	49.0	34.6	43.5	16.0
Refinery runs	**80.7**	**83.9**	**81.6**	**75.5**	**44.1**	**64.3**	**20.6**
Atlantic Basin	42.5	40.5	37.4	36.5	18.3	30.8	8.6
East of Suez	38.2	43.4	44.1	39.0	25.8	33.5	12.0

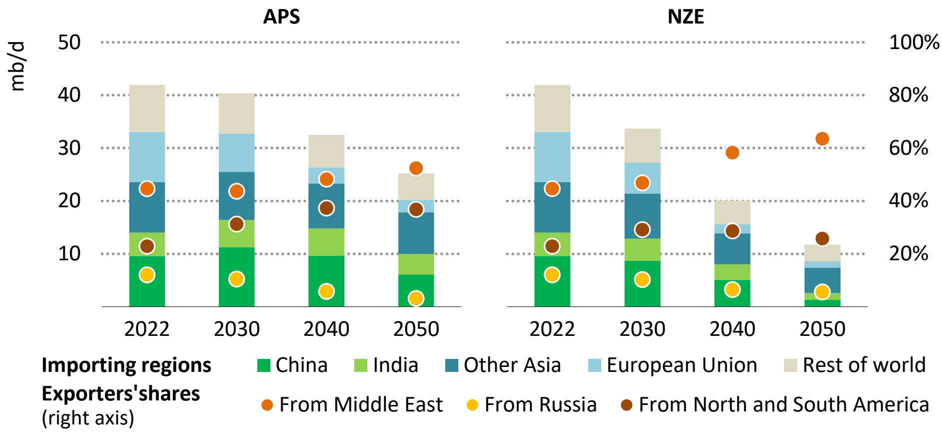
In the STEPS, global refining activity peaks around 2030 and remains at today's levels through to 2050. In the APS, global refinery runs halve over the period to 2050. Refining activities in the East of Suez region surpass those in the Atlantic Basic well before 2030 given that they benefit from relatively resilient domestic demand or competitive feedstock (Table 1.4). Some refiners, especially those in the Atlantic Basin, have begun adapting to a new market environment by converting their facilities into biorefineries, expanding into low-emissions businesses such as EV component production, hydrogen production and plastics recycling, or considering closures. In the NZE Scenario, refinery runs reduce further to 20 mb/d by 2050, around a quarter of today's level, mostly to produce petrochemical feedstock or other non-energy products such as asphalt and bitumen.

1.5.2 Oil trade

Global oil trade flows are increasingly concentrated on emerging market and developing economies in Asia, which currently account for just over 40% of global crude oil imports. Due to robust demand and limited domestic production, this region's share of global imports is set to rise to around 60% in both the STEPS and APS by 2050. The Middle East maintains its stronghold as the largest crude oil supplier, serving more than half of global import needs in 2050 in both the STEPS and APS. Although Russian crude oil is finding buyers in Asian markets and elsewhere, Russia's share of global crude oil exports continues to decline in all scenarios. North and South America play an increasingly important role in meeting the world's crude oil requirements, compensating for the loss of Russian volumes, as the reductions in the regions' refining activity outstrip the impacts of falling domestic production.

In the APS, the United States' share of global crude oil exports grows from 6% now to 15% in 2050, underscoring the region's emerging role as a swing player in global crude oil markets. In the NZE Scenario, the Middle East is set to play an outsized role in serving global crude oil markets as a low-cost producer, with its share of total exports surpassing 60% by 2050 (Figure 1.17).

Figure 1.17 ▷ Crude oil imports by region and exporters' shares by scenario



Crude oil import flows continue to focus on Asia; in the APS, the Middle East's strong position as the largest exporter is joined by the United States' growing role as a swing supplier.

The majority of new refining facilities under development are located in today's exporting regions for refined products, namely China, India and the Middle East. This makes it challenging to justify new refinery investments in importing regions such as Africa and Central and South America as new facilities would face intense competition from incumbent refiners overseas seeking export outlets. As both exporters and importers increase their reliance on trade, there is an increase in product trade volumes in the short term in the APS and the subsequent decline in trade is less steep than the pace of demand declines. Gross oil product exports in 2050 in this scenario are broadly similar to today's levels despite an over 45% reduction in overall oil demand.

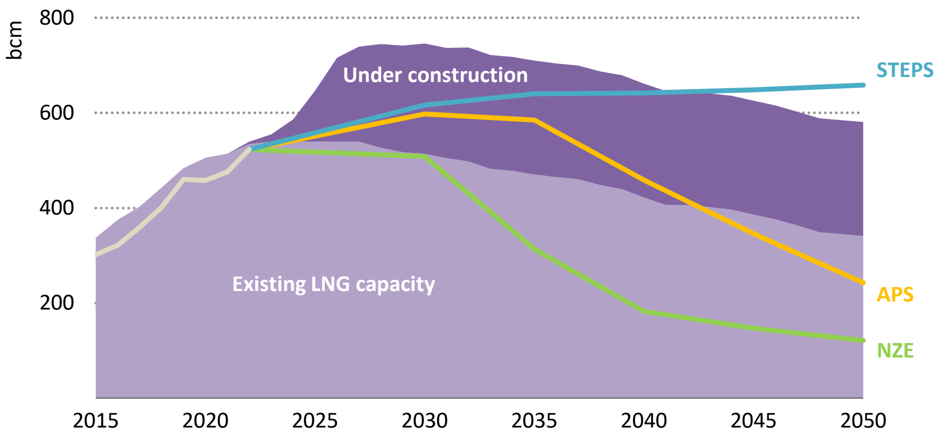
China's evolving policy of regulating crude oil and product trade has significant implications for global oil trade flows, given its imminent position as the world's largest refiner. To address excess product outputs and curb emissions in the refining sector, the Chinese government implemented quotas for both crude oil imports and oil product exports. In the first half of 2022 the reduction in product export quotas had a notable effect on global middle distillate supplies, leading to a surge in prices for these products. Conversely, an easing of crude oil import and product export quotas in late 2022 contributed to a moderation of diesel prices. These instances demonstrate the substantial impacts of China's trade policy shifts on product trade balances, as any changes in its trade regulations can cause significant fluctuations in product supplies and prices worldwide, especially for middle distillates such as diesel and kerosene (IEA, 2023b).

1.5.3 Natural gas trade

Around 20% of global natural gas production is traded over long distances, using either large-scale pipelines (440 bcm in 2022) or by liquefying the gas and shipping it by sea (530 bcm in 2022). Continued expansion of natural gas trade requires investment in this capital-intensive export infrastructure, which also requires high rates of utilisation. Buyers and sellers have therefore typically entered into long-term contracts with pre-agreed volumes that justify the high upfront costs of the projects.

Global natural gas trade in the STEPS increases by nearly 15% between 2022 and 2030 to reach 920 bcm. In the APS, growth slows to just 2%. In the NZE Scenario total trade contracts slightly, by 10%. Long-distance pipeline trade declines in all scenarios, diminished by significantly lower requirements for long-term, fixed volumes of gas deliveries. Interregional pipeline trade falls by nearly 10% in the STEPS, 25% in the APS and by 35% in the NZE Scenario between 2022 and 2030, as pipeline gas exports to Europe are rapidly reduced and a much lower level of pipeline-based trade takes place within North America.

Figure 1.18 ▷ Existing and under-construction LNG liquefaction capacity and LNG trade by scenario



In the NZE Scenario, LNG projects currently under construction are not necessary. In the APS, trade peaks by 2030 and the capacity utilisation of plants would drop significantly.

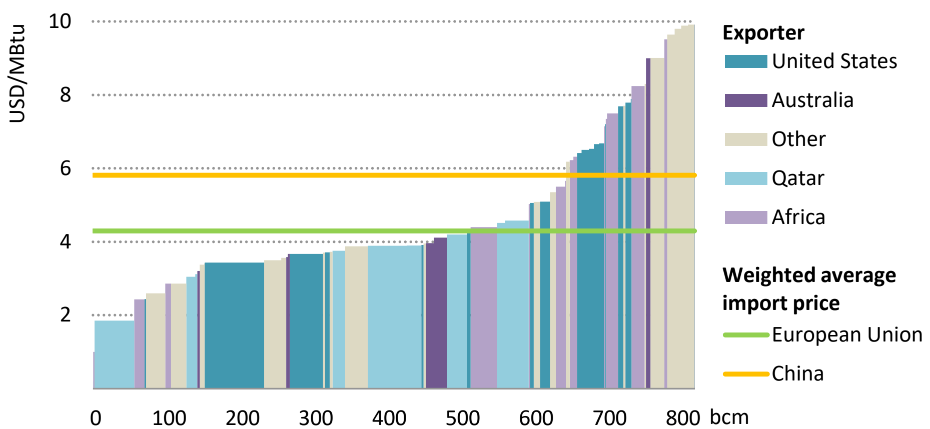
Notes: LNG trade reflects interregional trade between regions modelled in the Global Energy and Climate Model. LNG capacity is derated to 85% of nameplate capacity.

LNG is, by comparison, relatively resilient, growing by nearly 30% in the STEPS, and by 25% in the APS to 2030. It declines by around 5% in the NZE Scenario over the same period, even as overall natural gas demand falls by 20%. In all scenarios, global gas trade continues to pivot toward LNG, as the relatively large share of destination-flexible volumes provides a better match with the variable speed of transitions away from gas in different regions and sectors. Portfolio players continue to act as important intermediaries between supply and demand.

After 2030, LNG trade grows moderately in the STEPS, falls by 4% per year in the APS and by 7% per year in the NZE Scenario (Figure 1.18). By 2050, demand for LNG in the APS is nearly 300 bcm lower than today and is 400 bcm lower in the NZE Scenario. This story of near-term resilience but longer-term decline raises the question of whether investors are likely to recoup their invested capital, and what impact a possible surplus of LNG supply would have on benchmark gas prices.

The world currently has around 650 bcm of annual nameplate liquefaction capacity, with a further 250 bcm under construction. In the APS, since LNG demand no longer grows after 2030, the average capacity utilisation of LNG export terminals falls from around 90% between 2018 and 2022 to 80% by 2030. In the NZE Scenario, the sharp decrease in natural gas demand globally means that the majority of projects currently under construction are no longer necessary. If they do go ahead, aggregate capacity utilisation would fall to 65% in 2030 and several plants that are unable to compete in a supply glut would likely end up closing or being repurposed as a facility able to trade hydrogen-based fuels such as ammonia or methanol.

Figure 1.19 ▷ Delivered cost of existing and under-construction LNG supply compared with gas prices in the NZE Scenario, 2030



LNG exporters face intense competition for rapidly diminishing demand; most projects under construction fail to recoup their invested capital under NZE Scenario import prices.

This outcome depends largely on whether projects are able to recover their costs in the low gas price environments of the APS and NZE Scenario. On average, the delivered cost of LNG is around USD 4.50/MBtu (Figure 1.19). The most cost-competitive sources of supply are projects that have paid off their initial invested capital and benefit from low-cost feedgas and low operating costs, such as the Qatari LNG trains that started up in the early 2000s. Around 40% of existing projects have yet to recover fully their invested capital, having been online for less than the typical 10-year period over which debt is recovered in project finance for large-scale LNG terminals. For projects under construction, average delivered costs are estimated to be around USD 8/MBtu, and there is a risk that this may increase due to mounting cost inflation amid a crowded queue of projects.

In the NZE Scenario a glut of LNG and pipeline capacity forms in the mid-2020s, and weighted average import prices in China and the European Union fall to levels last seen at the height of the Covid-19 pandemic in 2020. This puts strains on the profitability of both existing and recently commissioned LNG projects. While shut-in risks would only appear if prices fall below feedgas and variable operating costs, there would be a degree of risk that project sponsors write off the value of the assets. This would, to a large extent, depend on contractual terms: suppliers selling LNG cargoes on a long-term take-or-pay basis could pass much of the volume and price risk to offtakers. Given the low oil prices in the NZE Scenario, oil indexation would offer little protection to sellers unless a floor price were set (such as through an S-curve formula). For suppliers without firm offtake contracts, LNG cargoes would have to be sold on the spot market at short-run marginal costs in order to avoid shutting in.

We estimate that the sponsors of around 70% of LNG export projects currently under construction would struggle to recover their invested capital in the NZE Scenario. In the APS gas prices are higher, but there are still some 80 bcm of projects – or 40% of what is currently under construction – that would not fully recover their invested capital.

1.6 Alternative supply pathways in the NZE Scenario

The rapid deployment of clean energy technologies and energy efficiency is at the core of the net zero transitions set out in the APS and NZE Scenario. In the NZE Scenario it is the surge in clean energy investment that leads to the overarching supply, price and investment trends and removes the need for any new long lead time conventional oil and gas projects.

The energy system transformation in the NZE Scenario is not the only possible pathway to reach the goal of net zero emissions by 2050. Similarly, the supply-side dynamics in the NZE Scenario are not the only way to meet a world with rapidly falling oil and gas demand.

Some producers have also argued that higher levels of oil and gas demand and supply than seen in the NZE Scenario could be consistent with achieving net zero emissions by 2050. This would be by deploying much greater levels of CCUS and negative emission technologies such as DACS and BECCS. This possibility is explored in Chapter 2.

A number of producers have set out reasons why their resources should be preferred in a declining oil and gas market. Four arguments are most prevalent, revolving around the need to prioritise: (i) resources in low-income countries that could be used to help boost economic development, (ii) resources with lower emission intensities, (iii) low-cost resources, and (iv) energy security, with a view to limiting oil and gas imports (this may also express itself in a preference for imports from geopolitical allies).

In this section, we explore the implications, benefits and trade-offs of boosting production in countries with a preference for the above factors (Box 1.3). Oil and gas demand levels are assumed to remain the same as in the NZE Scenario, and so the increases in production are matched in aggregate by decreases elsewhere. This may lead to large changes in projected oil and gas prices as well as changes in supplier concentration, emissions levels and income for producer economies.

Box 1.3 ▹ Description of NZE Scenario supply-side sensitivity cases

The four cases described below illustrate different ways to think through oil and gas supply in net zero transitions. They are framed here as sensitivities on the NZE Scenario, but the choices and trade-offs that they reveal are of broad relevance.

In the **low-income preference case**, it is assumed that countries with gross domestic product (GDP) per capita today below USD 10 000 develop their oil and gas resources in line with projections in the STEPS (Figure 1.20). To ensure that this additional production does not mean supply exceeds demand in the NZE Scenario, producers with the highest levels of GDP/capita today are assumed to cut back on production.

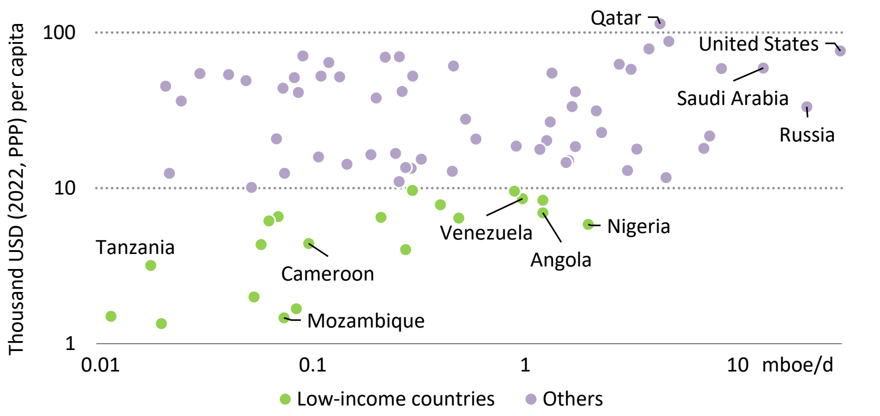
In the **emissions preference case**, production in the 40 countries with the current highest emissions intensities are assumed to decline at their natural decline rates. The lower level of production in these countries relative to the NZE Scenario is matched in aggregate by increases in production above levels in the NZE Scenario by countries with the lowest current emissions intensities. To examine the emissions implications of these changes in the geography of production it is assumed in this case that countries do not undertake any targeted efforts to reduce the emissions intensity of oil and gas operations (unlike in the NZE Scenario, which sees major efforts to reduce these).

In the **cost preference case,** resource holders with lower costs expand production above levels in the NZE Scenario. This leads to much lower prices than in the NZE Scenario, compelling higher-cost sources of production around the world to close earlier than would otherwise be the case.

In the **security preference case**, today's oil and gas importers look to reduce their import dependency to the extent possible by boosting domestic production. This reduces the level of oil and gas imports required globally, resulting in lower prices and lower production by high-cost exporters.

In many cases, although a number of countries see an increase in production above levels in the NZE Scenario, the overall declining market for oil and gas demand means that this manifests as a slower decline rate rather than an increase in production in absolute terms.

Figure 1.20 ▷ Oil and gas production and GDP per capita in selected countries, 2022



Multiple low-income countries today could develop additional oil and gas resources. These follow a higher production pathway in the low-income preference case.

Note: mboe/d = million barrels of oil equivalent per day.

Low-income preference case

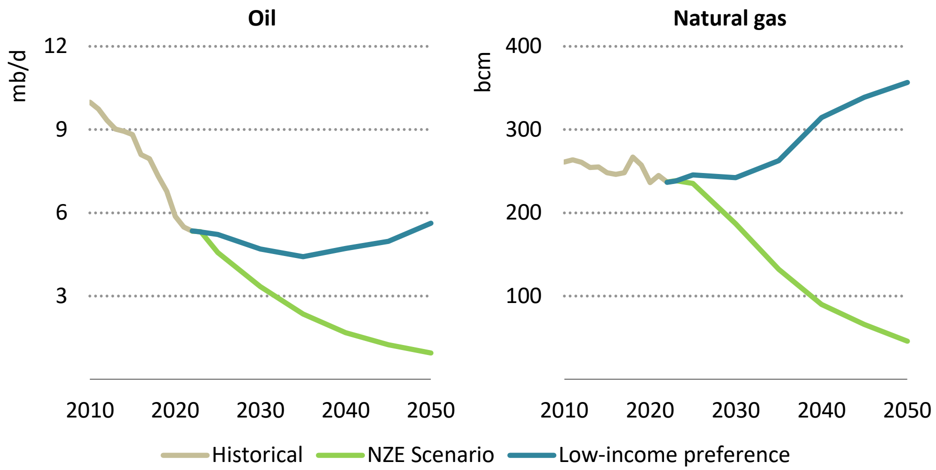
In the low-income preference case, production grows faster than in the NZE Scenario in a number of countries in Africa, especially Nigeria, Angola and Mozambique, as well as low-income countries in Asia Pacific, Eurasia, Latin America and the Middle East. In total, these countries produce around 5.5 mb/d and 360 bcm in 2050 (compared with around 1 mb/d and 50 bcm in the NZE Scenario in 2050) (Figure 1.21).

To avoid any oversupply of oil and gas, a number of high-income countries see lower production than in the NZE Scenario, including in the Middle East, Europe and North America (Figure 1.22). Production is assumed to fall at a maximum of the natural decline rates (around 8-9%) in these countries, although decline rates in these countries in this case tend to be much lower than this.[3]

Achieving the shift in production from high-income to low-income countries would likely be very challenging to realise in practice. One possibility would be for high-income countries explicitly to choose to ramp down production faster than in the NZE Scenario and provide support for the development of new projects in low-income countries through technical or financial support; but in reality there would be large risks of an oversupplied market.

[3] The decreases in production in higher-income countries relative to the NZE Scenario are generally small compared with their overall levels of production, meaning differences in decline rates are also small.

Figure 1.21 ⊳ **Oil and natural gas supply from low-income countries in the NZE Scenario and the low-income preference case**



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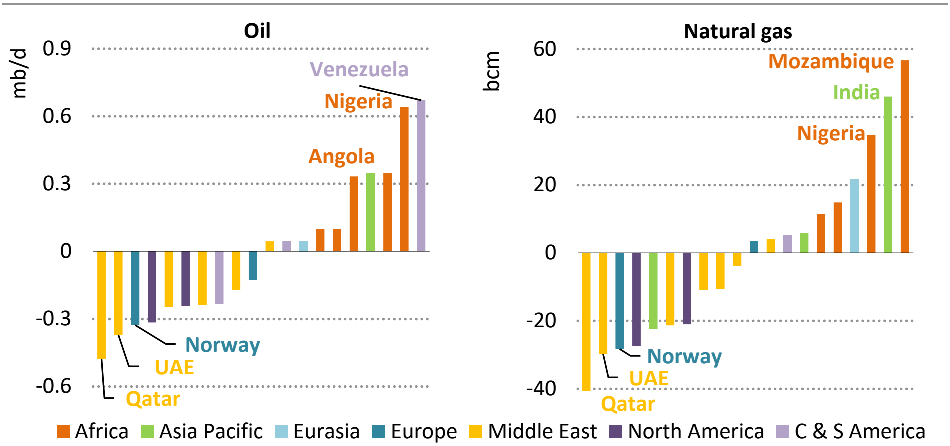
The low-income case sees much higher production in low-income countries, with natural gas production growing substantially to 2050.

Note: Low-income countries include those with GDP per capita today below USD 10 000 (PPP).

Figure 1.22 ⊳ **Increases and decreases in production relative to the NZE Scenario in the low-income preference case, 2040**



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The increases in production in low-income countries relative to the NZE Scenario are mainly balanced by reductions in countries in the Middle East, North America and Europe.

Notes: C & S America = Central and South America; UAE = United Arab Emirates. Shows only the 10 countries with the largest production increases and decreases.

In the low-income preference case, low-income countries spend around USD 1 800 billion more on oil and gas through to 2050 than the levels seen in the NZE Scenario (including both capital and operating costs). There is some less spending in existing projects in high-income countries than in the NZE Scenario but the overall cost of supplying oil and gas in this case is around USD 1 400 billion (23%) higher than in the NZE Scenario.

The low-income producers generate significantly more revenue from oil and gas sales than in the NZE Scenario. However, if oil and gas prices evolve as in the NZE Scenario, the additional capital and operating costs in low-income countries (USD 1 800 billion to 2050) would be greater than the additional revenue generated (USD 1 600 billion to 2050). This highlights a key risk for these countries. They could benefit from the broader economic activity linked to developing oil and gas resources and could use the produced energy to boost access to energy domestically. But, if the world is successful at scaling up clean energy in line with the NZE Scenario, low-income countries that develop their resources for export may struggle to generate any substantial returns or fiscal income from oil and gas sales.

Box 1.4 ▷ Prospects for natural gas developments in Africa

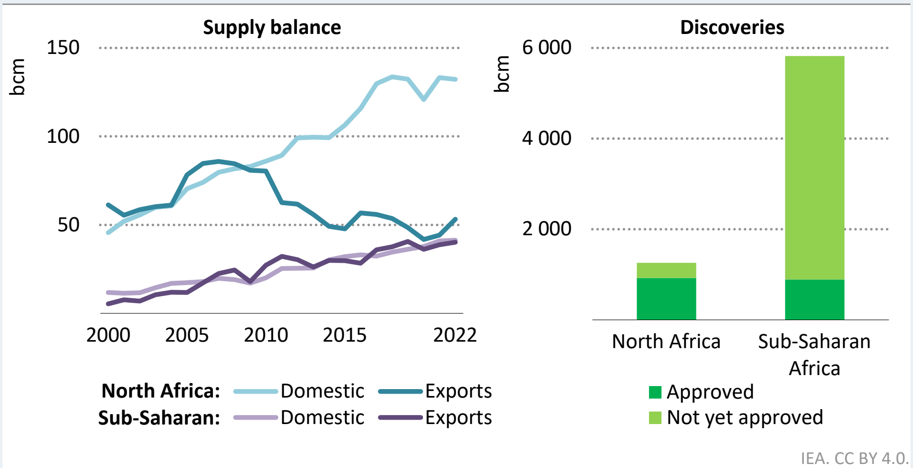
The current position of natural gas in Africa's energy mix varies widely across the continent. In North Africa, natural gas meets around half of the region's energy needs and domestic demand has run ahead of exports since 2010. In sub-Saharan Africa the share of natural gas in the energy mix is a mere 5%, and its use domestically has grown in parallel with large-scale export projects.

The top three producers in Africa – Algeria, Egypt and Nigeria – currently produce around 80% of the continent's natural gas. Around 7 000 bcm of natural gas resources have been discovered over the past decade across the continent and a number of countries are looking to substantially expand gas production. Around one-quarter of the gas discovered in the past decade in Africa has already been approved for development, including large developments in Mozambique, Mauritania and Egypt (Figure 1.23). If these projects are all completed on time, we estimate that they would provide around 70 bcm of gas per year by 2030.

The combustion of the gas from projects already approved would result in around 10 Gt of cumulative CO_2 emissions over the next 30 years. This is equivalent to around four months of emissions from the energy sector today. Africa's share of cumulative energy-related CO_2 emissions from 1890 to today is around 3%. If the cumulative emissions from burning this gas over the entire lifetime were added to Africa's current contribution, it would raise Africa's share to just under 3.5%.

These approved gas projects could provide a boost to economic activity, especially if they enable the expansion of local industry, generate well-paid local jobs or provide government income through royalties and taxes. In general, the export prices seen in the STEPS and APS would be high enough to cover production costs, but in the NZE Scenario much lower prices globally would mean that many of the projects would never recover their upfront costs and government income would likely be very low. Any gas projects developed could help to provide access to electricity and (via LPG) to clean cooking, where this remains to be achieved, but this would not provide much support to project economics given the low prices that low-income consumers could afford to pay. In all scenarios, project delays and cost overruns would severely challenge the commerciality of projects, especially those that have not yet been approved.

Figure 1.23 ▷ Africa's natural gas supply balance and status of resource discoveries made since 2010



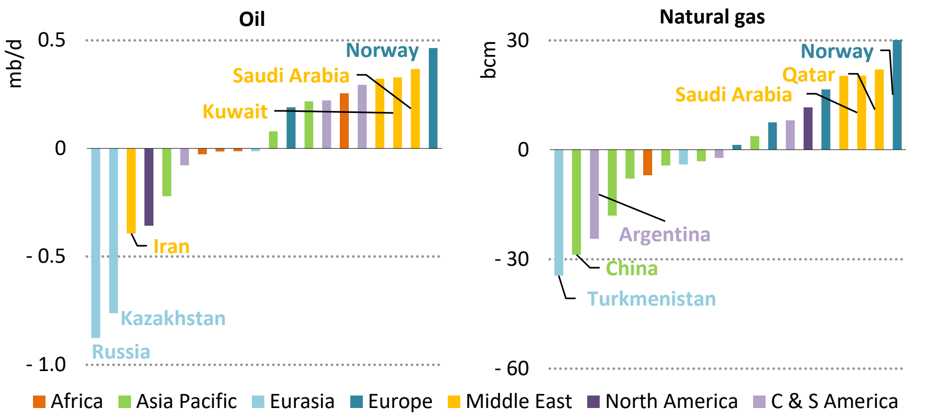
Developing sub-Saharan Africa's large resource discoveries would add little to its historical emissions burden; however, they fail to turn a profit in the NZE Scenario.

Emissions preference case

The emissions intensity of oil and gas operations in the worst-performing producers is five to ten times higher than the best performers (see Chapter 2). In the emissions preference case, production in countries with the lowest emissions intensity today is given preference over production in countries with the highest emissions intensity. In this case, countries with the highest emissions intensity produce around 3 mb/d and 140 bcm less oil and gas in 2040 than in the NZE Scenario, with some of the largest reductions seen in Russia, Turkmenistan, Kazakhstan and China (Figure 1.24). There is a commensurate increase in production in countries with the lowest emissions intensities, notably in Norway, Saudi Arabia and Qatar.

Looking at the period to 2030, the additional projects developed in the countries with the lowest emissions intensities means there is around USD 600 billion more spending on oil and gas above the levels in the NZE Scenario. This results in a 200 Mt CO_2-eq reduction in emissions from oil and gas operations in 2030. This is an important reduction in emissions from oil and gas operations, but it is far smaller and much more costly than the reductions in emissions from oil and gas operations that occur in the NZE Scenario.

Figure 1.24 ▷ Increases and decreases in production relative to the NZE Scenario in the emissions preference case, 2040



Shifting production from the highest to the lowest emitters cuts GHG emissions, but reductions would be lower and more costly than the reductions in the NZE Scenario.

Notes: C & S America = Central and South America. Shows only the 10 countries with the largest production increases and decreases.

In the NZE Scenario, all producers undertake extensive efforts to reduce the emissions intensity of their operations; this requires around USD 600 billion of spending to 2030. This investment cuts annual GHG emissions from oil and gas operations by 2 200 Mt CO_2-eq in 2030. The unit cost of reducing emissions from oil and gas operations through dedicated mitigation measures is therefore around ten times lower than the cost of reducing emissions by developing new projects in lower-emission countries.

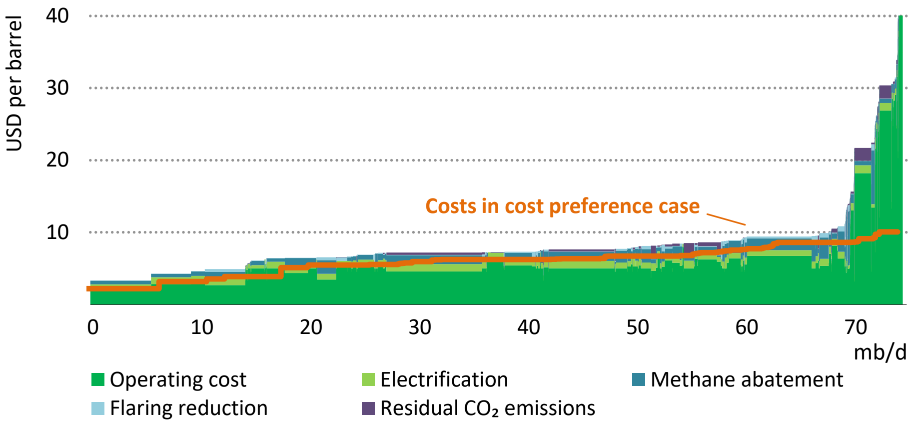
The changes in production in the emissions preference case could be achieved by countries introducing restrictions or fees based on the emissions intensity of oil and gas that is imported or consumed. In practice, these policy measures would also be likely to encourage producers with high emissions intensity to undertake targeted efforts to improve their operations. Indeed, these results show that this would be a much more cost-effective way to reduce emissions from oil and gas operations than developing new projects with low emissions intensity and trusting that these will displace higher emissions intensity sources of production.

Cost preference case

In the NZE Scenario, the strategies adopted by resource-rich governments and their NOCs play a key role in determining the overall level of oil and gas prices. Large oil and gas resource holders are assumed not to develop new fields even though there might be an economic case for them to do so. For example, the oil price of around USD 40/barrel in 2030 in the NZE Scenario would be more than sufficient to cover the capital and operating costs of new field developments in a number of the low-cost producers.

In the cost preference case, it is assumed that low-cost producers expand their production levels well above the levels in the NZE Scenario. Since oil and gas prices are assumed to be set by the operating costs of the marginal project, this pulls down oil and gas prices, forcing producers whose operating costs are higher than the oil price to shut down production to avoid making a loss (Figure 1.25).

Figure 1.25 ▹ Costs of oil production in the NZE Scenario and cost preference case, 2030



Almost 90% of oil can be produced for less than USD 10/barrel in the NZE Scenario. In the cost preference case, prices drop, and high-cost producers are pushed out of the market.

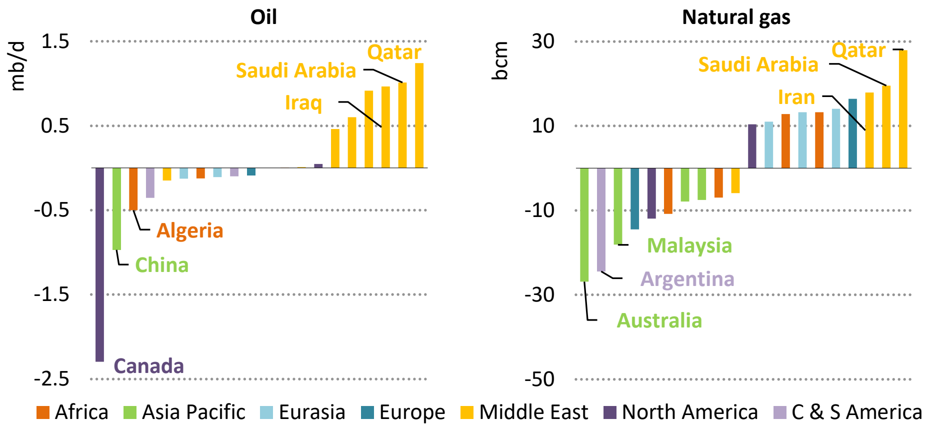
Note: Government taxes from production are not shown.

Low-cost producers – including Saudi Arabia, Qatar and Iraq – expand production above levels in the NZE Scenario and this means that the oil price falls to around USD 10/barrel in 2030. Prices remain at low levels and high-cost producers, including Canada, Australia and China, shut in around 5 mb/d of oil and 160 bcm of gas production in 2040 (Figure 1.26).

Around USD 500 billion is invested in new projects in low-cost producers to 2050. These have much lower operating costs than projects closed in high-cost producers, resulting in around USD 1 000 billion lower operating costs through to 2050 in the cost preference case than in the NZE Scenario. Total capital and operating costs over the period to 2050 are therefore around USD 500 billion lower than in the NZE Scenario.

A key risk for the low-cost countries looking to boost production is that it would result in much lower overall income from oil and gas sales. This risk is ever-present in oil markets today, but it would be significantly heightened against the backdrop of falling oil and gas demand. For example, in the cost preference case, countries in the Middle East produce more than 20 mb/d of oil in 2040, 30% more than in the NZE Scenario. But the lower oil price means they receive 60% less income from oil sales than in the NZE Scenario in 2040.

Figure 1.26 ▷ Increases and decreases in production relative to the NZE Scenario in the cost preference case, 2040



Low-cost producers could significantly boost supply, resulting in a further concentration of supply and very low prices. Such low prices would be very hard to maintain in practice.

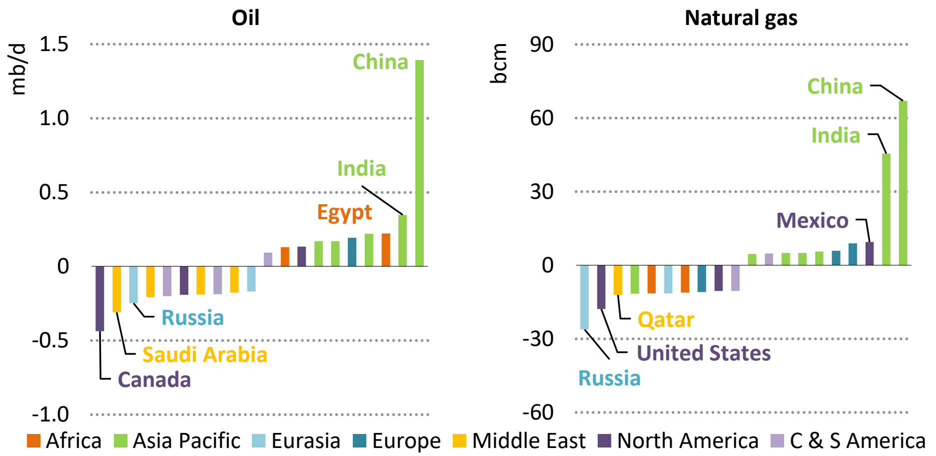
Notes: C & S America = Central and South America. Shows only the 10 countries with the largest production increases and decreases.

Many producer economies would likely struggle to withstand such a large impact on their fiscal balances. Avoiding this would rely on very rapid and successful implementation of economic reforms. Without much more diversified economies and sources of tax revenue, revenue from hydrocarbons in such a low-price world would not be sufficient to finance essential areas such as education, healthcare and public sector employment. These social pressures could also mean much more limited funding being available for continued investment in the upstream. This would lead to price volatility and turbulence and makes it unlikely in practice that prices could be maintained at very low levels for a prolonged period.

Security preference case

In the security preference case, importers are assumed to lower or eliminate taxes on domestic oil and gas operations – and in some cases subsidise operations – to boost production to levels seen in the STEPS. In 2030, importers produce close to 3 mb/d and 150 bcm more oil and gas than in the NZE Scenario, with some of the largest relative increases seen in China, India and Egypt. Globally, this means that net oil imports fall to around 32 mb/d in 2030 (8 mb/d less than in 2022) and gas imports to around 570 bcm (240 bcm less than in 2022). By 2040, importers produce 4 mb/d and 200 bcm more oil and gas than in the NZE Scenario (Figure 1.27).

Figure 1.27 ▷ Increases and decreases in production relative to the NZE Scenario in the security preference case, 2040



Efforts by importers to boost oil and gas production forces export-oriented producers to shut in production and could cause a fragmentation of international markets.

Notes: C & S America = Central and South America. Shows only the 10 countries with the largest production increases and decreases.

The smaller opportunity for exports causes international oil and gas prices to fall and a number of export-oriented producers are forced to reduce production.[4] In 2040, a 4 mb/d reduction in production by exporters would mean the oil price for exporters would fall to around USD 20/barrel in 2040. OPEC's share of the oil market in this case is 39% in 2040 and 41% in 2050, much lower than the levels seen in the NZE Scenario (44% in 2040 and 51% in 2050).

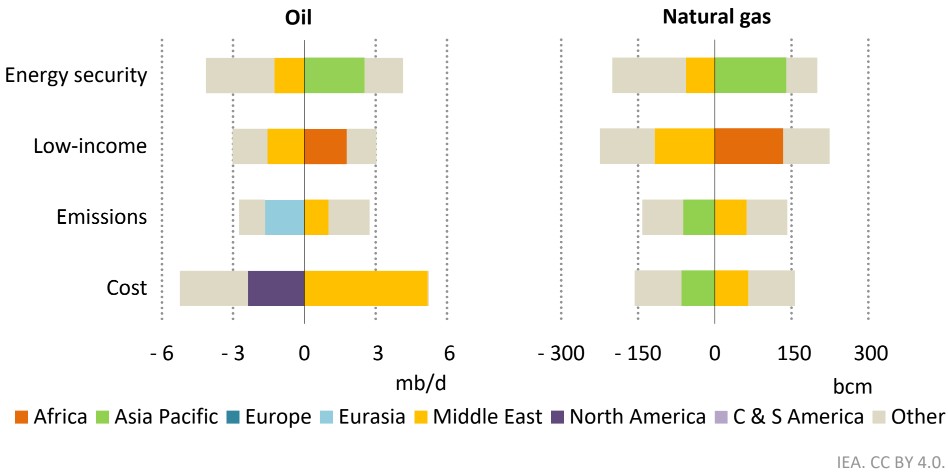
This case would see a major fragmentation of international oil and gas markets. Importers choose to forego cheap oil and gas available on the market to protect their domestic oil and gas industry. The overall cost for oil and gas supply is also much higher than in the NZE Scenario. To 2050, cumulative capital and operating costs for oil and gas supply is around USD 1 500 billion higher than in the NZE Scenario (a 25% increase). This case also includes some potential policy inconsistencies, with importers looking to protect – or even subsidise – domestic oil and gas companies even as they rapidly scale up clean energy investment and move away from fossil fuel use.

[4] High-cost exporters are assumed only to reduce production designated for export so that they can always meet their own consumption with domestic production to avoid becoming net importers.

Conclusions

The cases examined here highlight that different supply pathways are possible in a net zero emissions world (Figure 1.28). In general they achieve their starting aims, but they also see major potential downsides for producers, markets and net zero transitions.

Figure 1.28 ⊳ Differences in oil and gas production from the NZE Scenario in the sensitivity cases, 2040



Changes in preferences can reshape oil and natural gas production across regions, but increases in one part of the world must be matched by faster declines elsewhere.

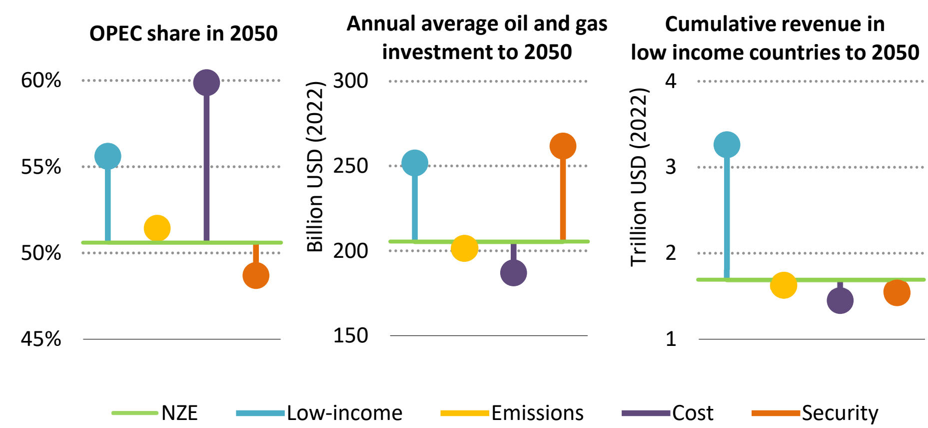
Note: C & S America = Central and South America.

- In the low-income preference case, oil and gas production in low-income countries is around 4.5 mb/d and 300 bcm higher in 2050 than in the NZE Scenario. But in the context of oil and gas prices in the NZE Scenario, many of these new projects would fail to generate a reasonable return and could become stranded assets.
- In the emissions preference case, emissions from oil and gas operations are reduced globally by around 200 Mt CO_2-eq in 2030. But this reduction is much smaller and more expensive than the reduction in emissions in the NZE Scenario, in which producers undertake targeted action to reduce their emissions intensity and emissions are cut by 2 200 Mt CO_2-eq in 2030.
- In the cost preference case, the total cost of supplying oil and gas to 2050 is 7% lower than in the NZE Scenario. But this case sees a further concentration of production – already visible in the NZE Scenario – among a small number of countries, and so may lead to heightened security of supply concerns. This case also sees lower commodity prices than in NZE Scenario and some producer economies would likely struggle to withstand the impacts on their fiscal balances.

- In the security preference case, most countries successfully cut their reliance on imports, and global oil and gas imports in 2030 are around 20% lower than today (compared with a 13% drop in the NZE Scenario to 2030). But achieving this would lead to a major fragmentation of international oil and gas markets, and means the cost of supplying oil and gas is around 25% greater than in the NZE Scenario to 2050.

A key assumption in the sensitivity cases is that overall demand levels do not change, with increases in production above the levels in the NZE Scenario by some countries matched by an identical level of reductions by others. Commodity prices could be the intermediary to allow for this, with new developments in one part of the world leading to lower prices and reductions in production in other parts of the world. Avoiding an increase in demand, however, may require policies to be further tightened above what already occurs in the NZE Scenario and there is a risk that this would not happen. Some of the cases examined would also imply a breakdown in international oil and gas markets as they are today, and it is not clear if prices would send a clear enough signal to avoid overproduction.

Figure 1.29 ▷ Selected security, cost and revenue indicators in the NZE Scenario and supply-side sensitivity cases



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The cases examined involve trade-offs between security, cost and oil and gas revenue in low-income countries. The NZE Scenario aims to chart a middle ground between these.

A world with rapidly declining oil and gas demand will inevitably involve trade-offs and compromises for producers and consumers between cost, security, emissions and equity concerns. In the NZE Scenario, the supply-side dynamics are based on the assumption that there is no development of new long lead time upstream conventional projects and that prices rapidly fall to the operating costs of the marginal project. While there is no single answer, this assumption means the NZE Scenario charts a middle ground between a number of the various trade-offs that exist (Figure 1.29).

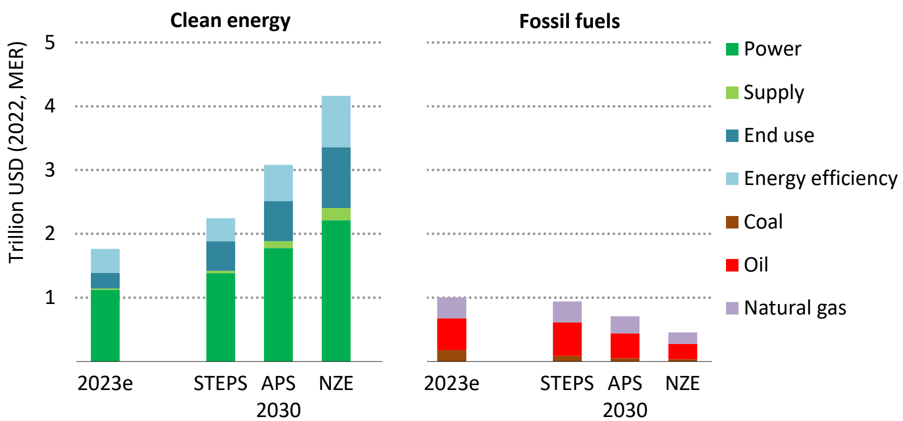
The above analysis focuses on the NZE Scenario, but many of the considerations also apply in the context of the APS. For example, in the APS, investment to reduce the emissions intensity of existing operations is still a more effective way to reduce GHG emissions than developing new fields. New conventional crude oil and gas developments are required in the APS, but with falling oil and gas demand there could still be intense competition for market share. Increases in production in one part of the world would likely require reductions elsewhere to avoid making the later stages of the transition even more challenging.

All producers can make arguments as to why their resources should be developed over others. In net zero transitions new project developments are, however, likely to face major commercial risks. Producers looking to undertake new resource developments need to explain how their plans are viable within a global pathway to net zero emissions by 2050 and be transparent about how they plan to avoid pushing this goal out of reach.

1.7 Investment

Total energy investment in 2023 is estimated to be USD 2.8 trillion. Of this, around USD 1.8 trillion will be invested in clean energy, and USD 1 trillion in oil, gas, and coal (including extraction, refining, transmission and distribution, and power plants that use these fuels). Both the APS and NZE Scenario see a major increase in clean energy investment, rising to USD 3.1 trillion in 2030 in the APS and to USD 4.2 trillion in the NZE Scenario (Figure 1.30). This boost in clean energy investment is the principal driver behind the drop in fossil fuel use that can be achieved while ensuring there is no shortfall in meeting energy service demands.

Figure 1.30 ▷ Investment in clean energy and fossil fuels by scenario

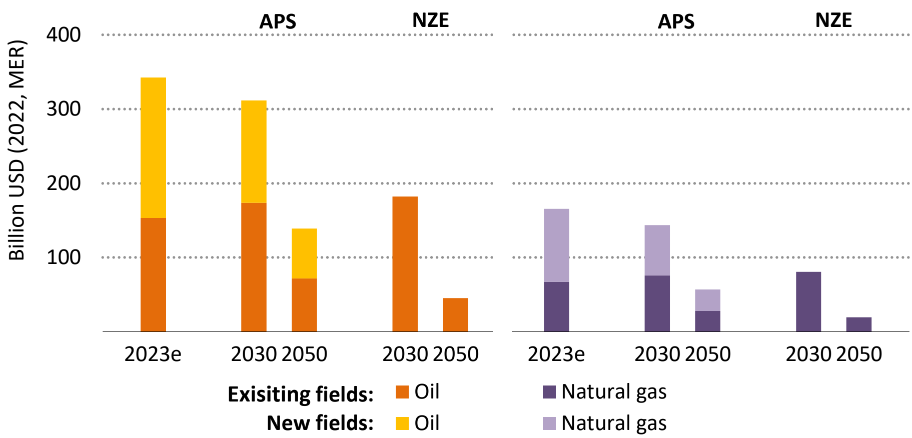


In the NZE Scenario annual fossil fuel investment drops by USD 500 billion to 2030 while clean energy investment increases by more than USD 2 trillion.

Note: 2023e = estimated values for 2023.

In the APS, investment is needed in both new and existing oil and gas projects: oil and gas investment in 2030 is around USD 650 billion, around 20% less than the expected level in 2023 (Figure 1.31). In the NZE Scenario, investment shifts entirely to maintaining production at existing fields, and to reducing the emissions intensity of oil and gas operations. Investment in oil and gas supply falls to USD 400 billion in 2030, half of the level in 2023. In both the APS and the NZE Scenario, the increase in clean energy investment is assumed to be synchronised with the scaling back of investment in fossil fuels. In reality, mismatches in investment levels are likely, and both over- and underinvestment in oil and gas could have important consequences for net zero transitions.

Figure 1.31 ▷ Investment in new and existing fields by scenario



Investment in oil and natural gas supply declines from current levels in both the APS and NZE Scenario. Capital spending in the NZE Scenario is focused entirely on existing fields.

1.7.1 Risks from overinvestment

Overinvestment could occur if the oil and gas industry invests for long-term growth in demand that does not materialise. This risk has always been a feature of oil and gas markets, but net zero transitions – and the prospect of long-term structural declines in oil and gas demand – would present a new and pervasive set of risks and uncertainties. In such a situation, oil and gas prices would fall and new projects would face major commercial risks and may fail to recover their upfront costs. Existing projects could be at risk if oil and gas prices remain below operating costs for a prolonged period. Moreover, it could lead to difficulties for producer economies in which oil and gas sales make up a significant share of exports and fiscal revenues.

Overinvestment in supply also risks locking in emissions that could push the world over the 1.5 °C threshold. This could be avoided by governments adopting resilient policies that prevent a drop in prices feeding through into a rebound in oil and gas demand. But in practice this may be difficult to stop. Additional emissions from new projects would therefore need to be compensated by even more robust emission reductions in the latter years of our projections to achieve net zero emissions by 2050.

Assessing the risks of stranded assets

A reduction in oil and gas production and prices could lead to widespread losses for the oil and gas industry and to stranded assets. There are multiple strands to this debate and it is therefore useful to distinguish between different impacts and losses that could be incurred by the oil and gas industry. In particular, it is helpful to distinguish between:

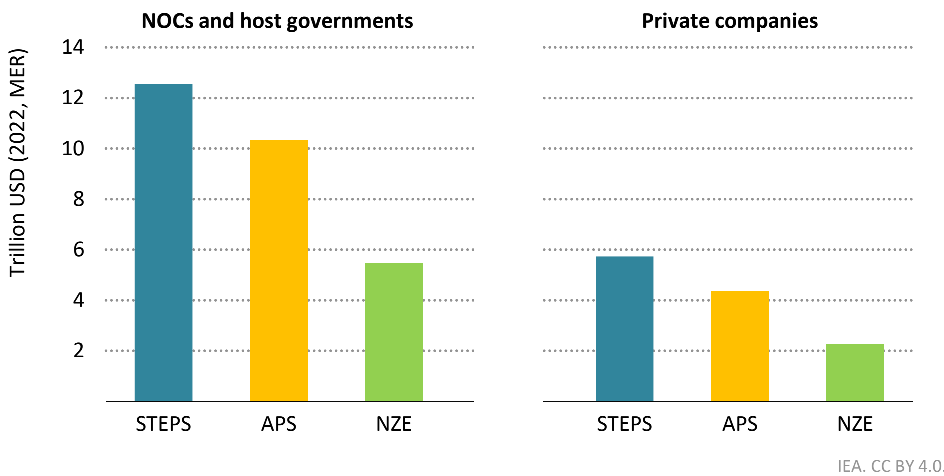
- **Stranded volumes:** existing fossil fuel reserves that are left unexploited as a result of climate policies.
- **Stranded capital:** capital investment in fossil fuel infrastructure that is not recovered over the operating lifetime of the asset because of reduced demand or reduced prices resulting from climate policies.
- **Stranded value:** a reduction in future revenue generated by an asset or asset owner, as assessed at a given point in time, caused by reduced demand or reduced prices resulting from climate policies.

The world currently has around 1.8 trillion barrels of oil and 220 trillion m^3 of natural gas 2P reserves. With reasonable assumptions on possible deployment rates of CCUS and negative emission technologies such as DACS and BECCS, a large proportion of these reserves cannot be combusted if the temperature rise is to be limited to well below 2 °C or 1.5 °C. For example, in the NZE Scenario around 30% of today's oil and natural gas reserves are produced by 2050. However, this does not necessarily mean that large volumes of reserves will be "stranded". In the STEPS, around half of oil and gas reserves are produced to 2050. In other words, a large amount of existing oil and gas reserves will not be used even under much higher temperature outcomes. There is undoubtedly a large difference in fossil fuel use between the scenarios, but the assessment of risks to the industry is better focused on investment and value losses rather than reserves.

In the NZE Scenario, despite the sharp reductions in demand, the risk of stranded capital is relatively low as it is mitigated by production decline rates that are consistent with no further investment in new projects. Some fields are closed before the end of their technical lifetimes, but most of these projects will have recovered their upfront capital by the time shut-in risks appear. In the upstream sector, stranded capital risks therefore exist primarily in the form of the sunk costs incurred in exploring for resources that are not ultimately developed in the NZE Scenario; we estimate that this amounts to around USD 400 billion in total.

Stranded capital risks are also present for large-scale infrastructure projects in the midstream part of the oil and gas value chain. These assets typically require a high rate of utilisation over their lifetime to recover their invested capital. In the NZE Scenario, none of the LNG export projects under construction today are required. If all projects under construction were to be developed, the drop in LNG demand in the NZE Scenario would mean the global average utilisation rate of LNG plants would fall from around 80% of nameplate capacity today to below 60% in 2030. In practice, these assets may still be able to avoid incurring stranded capital if their commercial structure is based on fixed cost recovery and long-term offtake agreements, but this would merely shift the losses onto a different entity. The risk of stranded capital would increase significantly if there were delays or "stop-go" policies related to emission reductions, or a misreading of market signals on the part of the industry.

Figure 1.32 ▷ Net present value of upstream oil and gas production



The value of the oil and gas industry diminishes sharply with increased climate ambition.

Notes: Values shown for NOCs and host governments are the sum of pre-tax discounted net income; for private companies it is the post-tax discounted net income. Uses a discount rate of 10%.

The more relevant metric for the financial sector and the oil and gas industry is likely to be estimates of potential stranded value. If the expectations of the financial sector are that demand and prices will evolve in a similar way to the STEPS, private oil and gas companies would have a total value today of just under USD 6 trillion (Figure 1.32). This value is cut by around one-quarter in the APS and by 60% in the NZE Scenario. The net present value of NOCs today is much higher than private companies, given their larger share of global production from lower cost resources. Their value drops by a similar rate in the APS and NZE Scenarios, but this equates to a much larger reduction in absolute terms. NOC income generated for host countries is critical to the fiscal balances of many economies, and the drop in value is liable to negatively impact sovereign credit ratings unless efforts are made to diversify economies away from hydrocarbons (see Chapter 4).

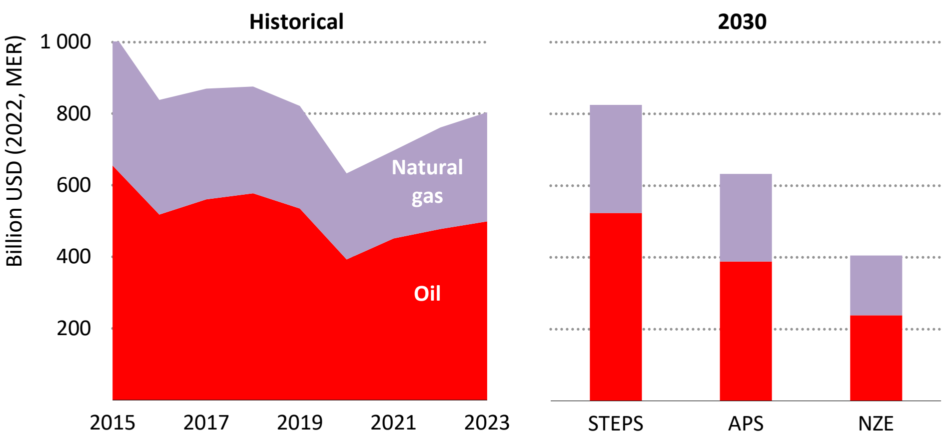
For companies, stranded value could materialise as large-scale write-offs, damaging their creditworthiness and raising the cost of both equity and debt. With lower asset and corporate valuations, higher risks would be attached to companies that produce or transport oil and gas, putting pressure on companies to diversify their business model and limiting the scope for dividends and buybacks that have historically attracted investors to the sector. Stricter lending criteria and restricted access to capital could also weigh on the ability of oil and gas companies to raise debt, even for activities that might contribute to lower emissions.

1.7.2 Risks from underinvestment

If supply were to transition faster than demand, with a drop in fossil fuel investment preceding a surge in clean energy technology deployment, this would lead to much higher and more volatile prices, even if the world is moving towards net zero emissions. For example, if the oil and gas industry invests for the NZE Scenario or APS, but demand continues to grow for some time (as in the STEPS), there would soon be a major shortfall in supply. This would lead to major issues over the security of supply, especially if only certain parts of the oil and gas industry or geographies choose to cut back on production in advance of wider efforts to cut demand.

The higher price that would result from underinvestment could reduce demand, but the impact on emissions is less clear-cut. For example, the record high natural gas prices in the European Union in 2022 resulted in a 3% increase in power sector emissions because of increases in the use of coal. High oil and gas prices are also highly regressive and cause financial difficulties for more vulnerable households and those with limited access to essential energy products. High oil and gas prices can therefore have significant impacts on economic growth and the competitiveness of particularly energy-intensive industries, and they should not be viewed as a viable or desirable substitute for climate policies.

Figure 1.33 ▷ Historical investment in oil and gas and needs in 2030



Recent investment levels are much higher than required in the APS and NZE Scenario in 2030; the risks now appear weighted more towards overinvestment than underinvestment.

Previous editions of the *World Energy Outlook* warned of a risk of underinvestment in a STEPS-like trajectory for demand, with a gap between the amounts being invested in oil and gas and the future requirements of this scenario. The situation has evolved and this is no longer the case (Figure 1.33). Oil and gas investment has risen in recent years and the benchmark level of investment needed in 2030 has come down, meaning that the level of investment in oil and gas expected in 2023 is now broadly equivalent to the level needed in the STEPS. The fears espoused by some large resource holders and certain oil and gas companies that the world is underinvesting in oil and gas supply are no longer based on the latest technology and market trends. Indeed, the amount of investment expected in 2023 is significantly higher than what is needed in the APS and almost double NZE Scenario levels in 2030. This implies that the oil and gas industry does not expect there to be any significant near-term reduction in demand and, when it comes to the overall adequacy of current spending trends, the risks are currently weighted more towards overinvestment in oil and gas than the opposite.

Technology options for the oil and gas industry

SUMMARY

- The production, transport and processing of oil and gas resulted in 5.1 billion tonnes (Gt) CO_2-eq in 2022, just under 15% of total energy-related GHG emissions and equivalent to all energy-related GHG emissions from the United States. The emissions intensity of the worst-emitting producers is currently five to ten times higher than the best performers. In the NZE Scenario, these emissions are cut by more than 60% by 2030 and the emissions intensity of global oil and gas operations is near zero by the early 2040s, with many individual producers achieving this considerably earlier.
- Methane emissions account for nearly half of the sector's current scope 1 and 2 emissions. Tackling methane is the most important measure to reduce these emissions. Other key levers include: 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 hydrogen in refineries. The 60% cut in scope 1 and 2 emissions by 2030 in the NZE Scenario requires around USD 600 billion of spending to 2030.
- The oil and gas industry is investing in many clean energy technologies and a number of options have a close affinity to its existing skills and resources. These technologies address 30% of final energy consumption in the NZE Scenario in 2050 and include:
- **CCUS:** the oil and gas industry is involved in 90% of CCUS capacity in operation. CCUS and direct air capture are key technologies to achieve net zero emissions, especially in some difficult-to-decarbonise sectors, but they are not a way to retain the status quo.
- **Low-emissions hydrogen and hydrogen-based fuels:** oil and gas companies are partners in a large share of planned hydrogen projects that use CCUS and electrolysis. In the NZE Scenario, low-emissions hydrogen use rises by a factor of 110 to 2030.
- **Bioenergy:** more than half of total clean energy spending by the industry in 2022 was in bioenergy as a number of companies took major stakes in bioenergy producers.
- **Offshore wind:** around 2% of offshore wind capacity currently in operation was developed by oil and gas companies. Plans are expanding, including for floating turbines that are needed to tap the large wind potential in deep water.
- **Geothermal:** this sector shares many similarities with upstream operations, especially for a number of new and emerging technologies. The industry is currently only involved in a fraction of projects, but there are significant growth opportunities.
- **Plastics recycling:** a large number of planned chemical plastic recycling projects involve oil and gas companies. The industry can play a key role in reducing the high emissions intensity of chemical recycling today.
- **EV charging:** the oil and gas industry is responsible for 15% of global investment in public EV chargers currently. The number of EV chargers increases five to sixfold by 2030 to support the growth of electric light-duty vehicles in the APS and NZE Scenario.

2.1 Introduction

There is much the oil and gas industry can do to accelerate net zero transitions. An essential first step is to reduce the emissions that occur during oil and gas operations. The process of extracting oil and gas from the ground, processing it and transporting it to consumers results in considerable emissions. These emissions must be cut to near zero to achieve global climate targets. A major reduction in methane emissions to the atmosphere by 2030 is the single most important and cost-effective way for the oil and gas industry to bring down its emissions.[1]

Net zero transitions ultimately require low-emissions electricity, liquids and gases to satisfy the world's demand for energy services without the associated emissions. This requires all stakeholders – governments, businesses, investors and citizens – to take immediate and rapid action. The oil and gas industry can support and accelerate this process in multiple ways. The skills and resources developed and honed by the industry during oil and gas extraction, processing and transport have potential crossovers with many of the key clean energy technologies needed to deliver net zero transitions. They include areas where emission reductions are likely to be most challenging.

The industry also has an enormous degree of agency in how net zero transitions evolve. Governments have to take the lead, but by advocating for supportive policies and conditions, and demonstrating ambition in line with net zero transitions, the oil and gas industry can help create a transition in which its core skills and expertise still have a place.

This chapter initially looks at current emissions levels from traditional oil and gas operations around the world, the technologies and measures needed to cut these emissions, and their deployment in the Announced Pledges Scenario (APS) and Net Zero Emissions by 2050 (NZE) Scenario. It then examines the oil and gas industry's engagement with clean energy technologies to date and looks at its potential to help scale up a selection of clean technologies that should have a large degree of overlap with its existing skills and expertise.

2.2 Traditional oil and gas operations

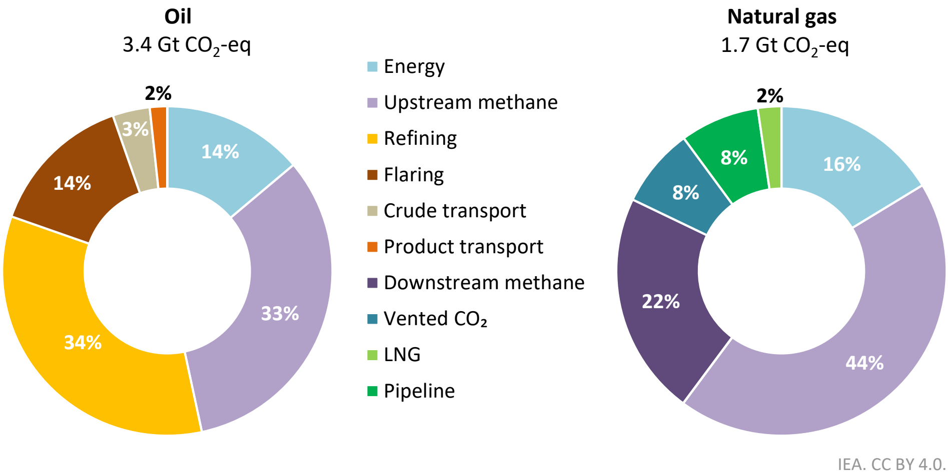
2.2.1 Current emissions from oil and gas operations

The production, transport and processing of oil and gas resulted in 5.1 billion tonnes (Gt) CO_2-eq in 2022 (Figure 2.1). 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.[2]

[1] Two reports, *Emissions from Oil and Gas Operations in Net Zero Transitions* (IEA, 2023a) and *Financing Reductions in Oil and Gas Methane Emissions* (IEA, 2023b), were published in 2023 to inform discussion on these topics ahead of the COP28 Climate Change Conference in Dubai.

[2] In this report, "scope 1" emissions are taken as emissions that come directly from the oil and gas industry itself. "Scope 2" emissions arise from the generation of energy that is purchased by the oil and gas industry. "Scope 3" emissions for the oil and gas industry occur mainly during the combustion of the fuels by end users.

Figure 2.1 ▹ Breakdown of GHG emissions from oil and gas supply, 2022



Methane emissions account for nearly half of all GHG emissions from oil and gas operations.

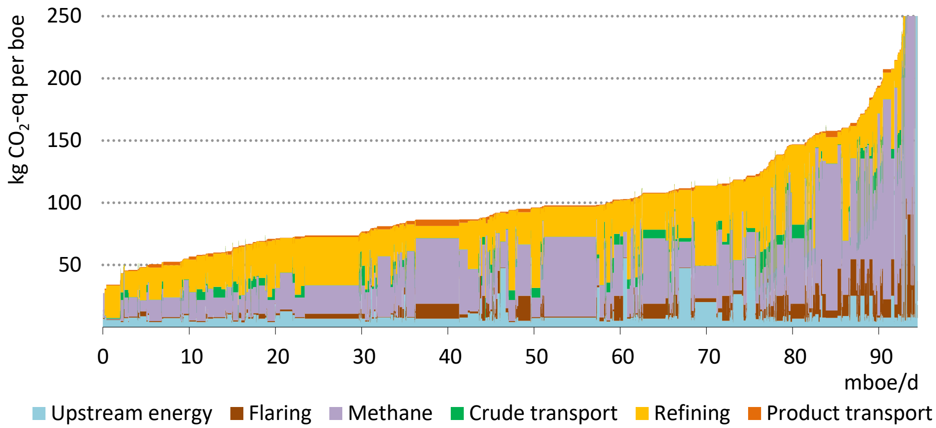
Notes: One tonne of methane is taken to be equivalent to 30 tonnes of CO_2 based on a 100-year global warming potential (IPCC, 2021). LNG = liquefied natural gas.

These emissions come from a variety of sources along 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 (Figure 2.2). Natural gas also undergoes processing to separate natural gas liquids and remove impurities such as CO_2, hydrogen sulphide and 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.

There are multiple potential sources of fugitive and vented methane emissions along oil and gas supply chains. We estimate that upstream oil operations resulted in 45 million tonnes (Mt) of methane emissions in 2022, upstream natural gas operations around 25 Mt and natural gas transport just over 10 Mt. This is equivalent to 2.4 Gt CO_2-eq in total. Methane emissions account for around two-thirds of total scope 1 and 2 emissions for natural gas.

Scope 1 and 2 CO_2 emissions from oil and gas supply chains totalled 2.7 Gt CO_2 in 2022. Of this, the energy required for oil and gas extraction and processing resulted in 0.7 Gt CO_2. Refining, including natural gas liquids (NGL) fractionation and bitumen upgrading, resulted in around 1.2 Gt CO_2, and oil and gas transport resulted in a further 0.4 Gt CO_2. Gas flaring, predominantly at oil production facilities, resulted in 0.3 Gt CO_2 emissions and we estimate 0.1 Gt of naturally occurring CO_2 was vented to the atmosphere during gas operations (Figure 2.3).

Figure 2.2 ▻ Spectrum of scope 1 and 2 emissions for oil, 2022

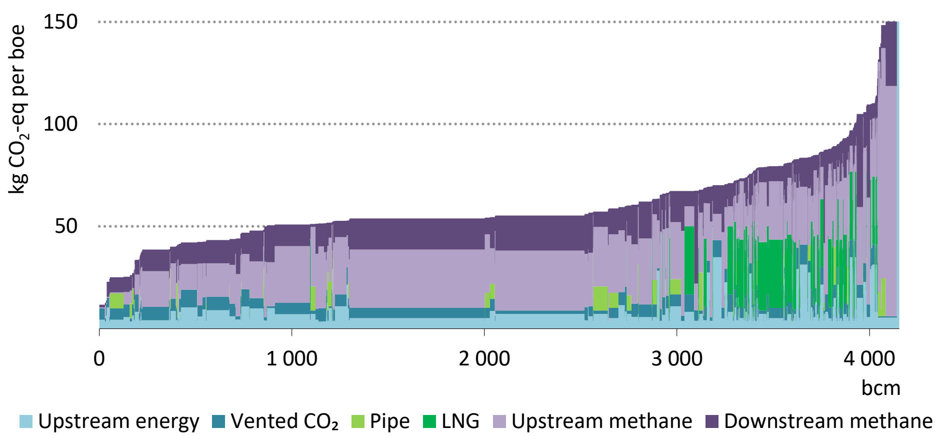


IEA. CC BY 4.0.

Oil operations were responsible for 3.4 Gt CO_2-eq emissions in 2022, nearly 10% of all energy-related GHG emissions.

Notes: kg CO_2-eq per boe = kilogramme of carbon dioxide equivalent per barrel of oil equivalent; mboe/d = million barrels of oil equivalent per day.

Figure 2.3 ▻ Spectrum of scope 1 and 2 emissions for gas, 2022



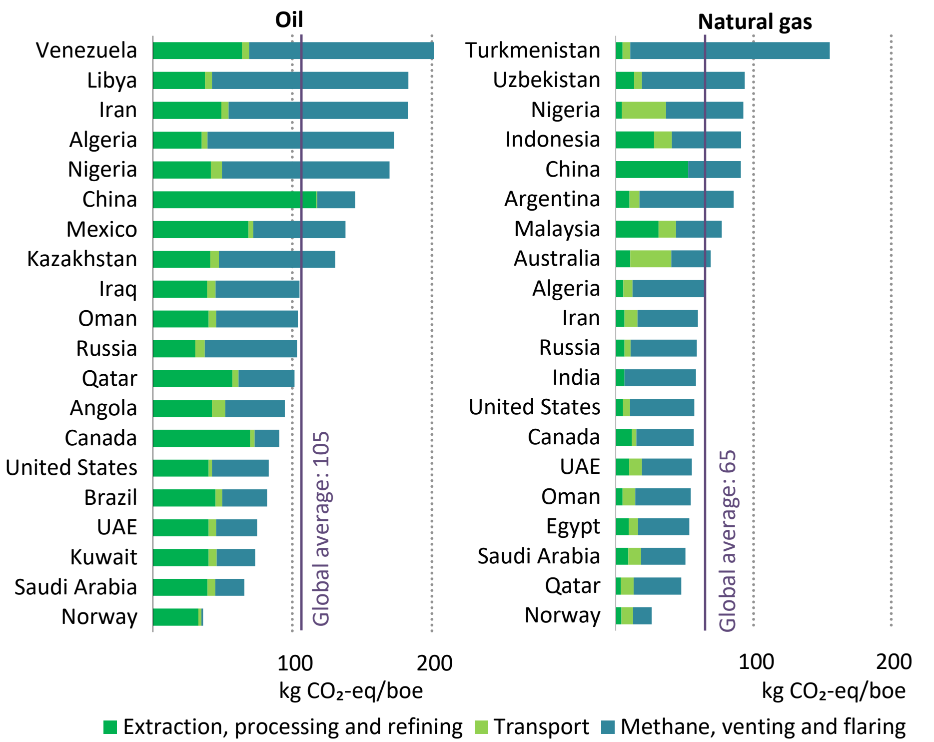
IEA. CC BY 4.0.

Natural gas operations were responsible for 1.7 Gt CO_2-eq emissions in 2022, close to 5% of all energy-related GHG emissions.

Note: bcm = billion cubic metres.

Putting these figures together, around 105 kg CO_2-eq is emitted on average for each barrel of oil equivalent (boe) produced; this is 20% of the full life cycle emissions intensity of oil when combusted. Extraction, processing and refining account for 50 kg CO_2-eq/boe, methane emissions and flaring add nearly 50 kg CO_2-eq/boe and transport operations add 5 kg CO_2-eq/boe. For natural gas, scope 1 and 2 emissions are just over 65 kg CO_2-eq/boe produced, 15% of the full life cycle emissions of natural gas that is combusted.

Figure 2.4 ▷ Countrywide average emissions intensity of the largest oil and gas producers, 2022



IEA. CC BY 4.0.

Among the world's largest oil and gas producers, the emissions intensity of the worst performers is five to ten times higher than that of the better ones.

Notes: Emissions from transport depend on the mode and distance travelled and are larger for countries that export a larger share of their production as LNG. Reflects estimates for 2022, which may differ from levels for 2023 given the recent introduction of measures and policies by a number of countries and companies.

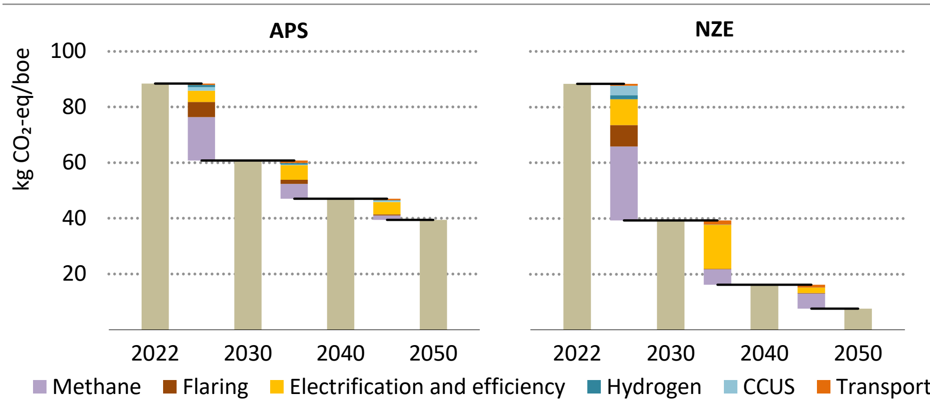
Sources: IEA estimates using: for energy for extraction and processing, a detailed field-by-field dataset created by the Rocky Mountain Institute (RMI, 2023) using the Oil Production Greenhouse Gas Emissions Estimator (Brandt et al., 2022); for refining, process-level information from the Petroleum Refinery Life Cycle Inventory Model (PRELIM) (Bergerson, 2022); for flaring, data from the World Bank (2023); for methane estimates, the Global Methane Tracker (IEA, 2023c); for transport, crude oil, oil product, LNG and pipeline trade, data from IEA (2023d) and assumed distances and emissions intensities. See IEA (2023a) for further information.

There is a strikingly broad range of emissions for different types of oil and gas supply. The emissions intensity of the worst-performing countries is five to ten times higher than the best-performing ones (Figure 2.4). For oil, emissions intensity tends to be lower in places where the oil is easy to extract (e.g. Saudi Arabia) or where refining and consumption take place close to the point of extraction (e.g. United States). Intensity is also typically lower in locations that have low methane emissions (e.g. Norway) or produce light oil or NGLs, which can be processed by simple refineries or bypass the refining sector entirely. Natural gas also has a wide range of methane emissions intensity associated with production from different regions. The high energy intensity of transport means that countries tend to have a higher overall emissions intensity if they export a large share of their production as liquefied natural gas (LNG) or by long-distance pipeline (LNG liquefaction results in around 5 kg CO_2-eq/boe globally on average).

2.2.2 Emission reductions to 2050 by scenario

In the APS, the global average scope 1 and 2 emissions intensity of oil and gas production falls by around one-third between 2022 and 2030, and by 55% by 2050.

Figure 2.5 ▷ Global average scope 1 and 2 emissions intensity of oil and gas production by scenario and reduction measure to 2050



Emissions intensities fall by more than 50% by 2030 in the NZE Scenario, mainly from cuts in methane. Flaring reduction, electrification, hydrogen use and CCUS also play key roles.

Notes: CCUS = carbon capture, utilisation and storage applied to hydrogen production at refineries or to supply refineries; also includes CCUS deployed in upstream facilities to abate co-produced CO_2 emissions. Hydrogen is the use of low-emissions electrolysis hydrogen to replace hydrogen from unabated fossil fuels.

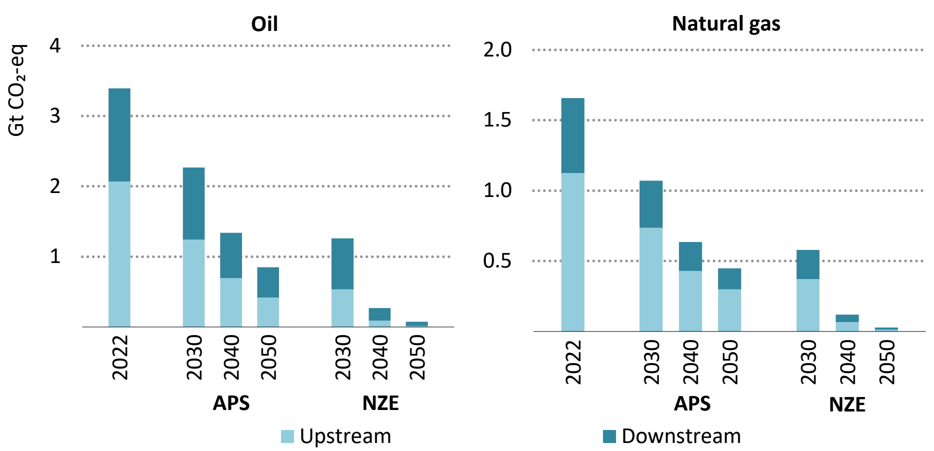
In the NZE Scenario, a concerted effort by all oil and gas companies worldwide to cut down on emissions means the global average emissions intensity of oil and gas production falls by more than 50% between 2022 and 2030. This is broadly equivalent to all of the world's oil and gas companies performing close to the emissions intensity of the best operators today.

The emissions intensity of upstream oil operations falls by around two-thirds to 2030 and it falls by around one-third for refining. For natural gas, the upstream emissions intensity falls by around 60% by 2030, with a near 55% reduction in the emissions intensity of gas transport.

Five key levers are used to drive these reductions in emissions intensity: tackling methane emissions, eliminating non-emergency flaring, electrifying upstream facilities with low-emissions electricity, equipping oil and gas processes with CCUS, and expanding the use of low-emissions electrolysis hydrogen in refineries. Cutting methane emissions is the single most important measure that contributes to the overall fall in emissions from oil and gas operations to 2030, followed by electrification and efficiency, and eliminating flaring (Figure 2.5). Scaling up CCUS and expanding the use of low-emissions hydrogen have a larger impact in the NZE Scenario, as does the use of low-emissions fuels in ships transporting oil and gas.

After 2030, total emissions from oil and gas operations fall to 0.4 Gt CO_2-eq in 2040 and to 0.1 Gt CO_2-eq in 2050 (Figure 2.6). By 2050, oil supply results in less than 10 kg CO_2-eq/boe, with refineries responsible for around three-quarters of this; the emissions intensity of natural gas is less than 5 kg CO_2-eq/boe.

Figure 2.6 ⊳ Scope 1 and 2 oil and gas emissions in the APS and NZE Scenario



IEA. CC BY 4.0.

Emissions from oil and gas operations fall by more than 60% by 2030 and by 98% by 2050 in the NZE Scenario. There are also large reductions in scope 1 and 2 emissions in the APS.

Around USD 600 billion of cumulative spending is required in the NZE Scenario to 2030 to achieve the greater than 50% reduction in the emissions intensity of oil and gas operations. Electrification requires around USD 260 billion, CCUS another USD 110 billion, and low-emissions hydrogen projects would demand nearly USD 80 billion. Methane and flaring abatement, which together provide 70% of the reduction to 2030, each requires less than

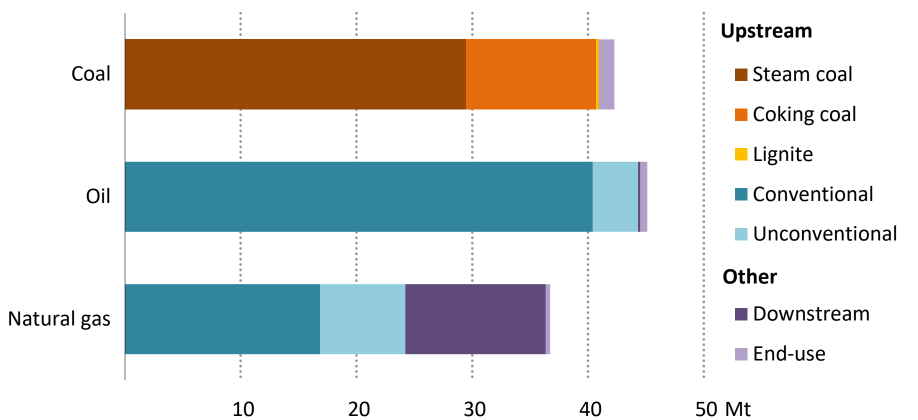
USD 80 billion of spending to 2030. Electrification and reducing methane and flaring can lead to additional income streams by avoiding the use or waste of gas, meaning they can quickly recoup the upfront spending required. By 2030, these three measures could provide more than 200 bcm of additional natural gas. Despite low gas prices in the NZE Scenario, these gas sales would be worth around USD 30 billion on average each year.

2.2.3 Cutting methane and flaring

Methane

Oil and gas operations were responsible for around 80 Mt of methane emissions in 2022 (a further 40 Mt were released from coal operations) (Figure 2.7).[3] Methane constitutes nearly half of total scope 1 and 2 emissions from the oil and gas sector, although there are significant variations between different regions. Reducing methane emissions is the single most important measure that companies can take to reduce their scope 1 and 2 emissions intensity.

Figure 2.7 ▹ Methane emissions from fossil fuels, 2022



Upstream operations are responsible for 85% of methane emissions from oil and gas supply; downstream emissions are mostly from natural gas transport and distribution.

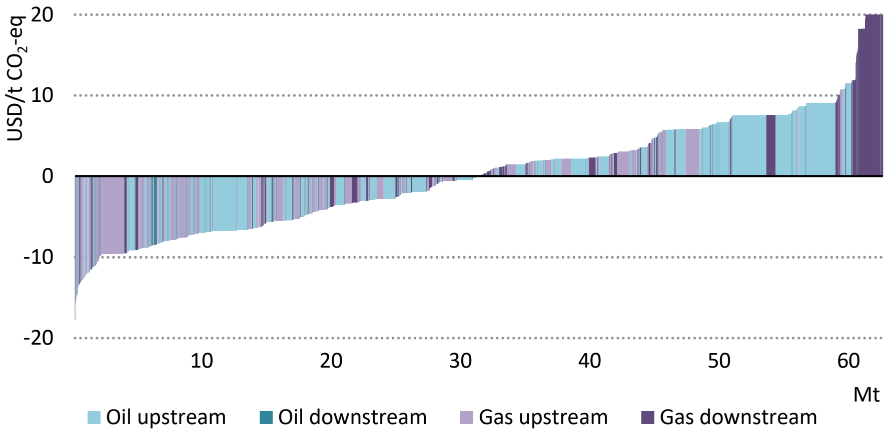
Notes: Other includes emissions from gas transport facilities, refining and emissions at the point of end use.

Oil and gas sector methane emissions could be reduced globally by 75% by implementing well-known measures such as leak detection and repair programmes and upgrading leaky equipment. Stopping all non-emergency flaring and venting is the single most impactful measure; that alone would cut methane emissions from oil and gas operations by nearly 20%.

[3] Information on policies and measures to reduce coal mine methane is available in the *Global Methane Tracker* (IEA, 2023c) and *Driving Down Coal Mine Methane Emissions: A regulatory roadmap and toolkit* (IEA, 2023e).

Methane abatement in the oil and gas industry is one of the cheapest options to reduce GHG emissions anywhere in the economy. This is both because methane is a very potent GHG and because the gas that is captured can often be sold to offset the cost of the abatement measure. We estimate that around 40% of methane emissions globally from oil and gas operations could be avoided at no net cost (Figure 2.8).[4] Even if there was no value to the captured gas, almost all available abatement measures would be cost-effective in the presence of an emissions price of about USD 20/tonne CO_2-eq. Methane abatement nonetheless faces a number of challenges, including information gaps, missing infrastructure and economic barriers (IEA, 2021a). Government policy and regulation are critical to removing or mitigating obstacles that prevent companies from getting started and going further.

Figure 2.8 ▻ Oil and gas methane abatement cost curve at average 2017-2021 prices



IEA. CC BY 4.0.

Just over 60 Mt – more than 75% of current oil and gas sector methane emissions – can be avoided with existing technologies. Around 40% of emissions could be cut at no net cost.

Preventing and quickly addressing very large leaks is a key opportunity to rapidly reduce methane emissions. The Methane Alert and Response System is one example of a programme that uses satellites to detect very large leaks and provide timely alerts to operators and regulators (UNEP, 2023). The Oil and Gas Climate Initiative is also operating a satellite-monitoring pilot programme at sites in Iraq, Kazakhstan, Algeria and Egypt and plans to expand the initiative to other countries (OGCI, 2023). Continuous monitoring systems are also being deployed at a number of facilities to tackle fugitive sources and improve emissions quantification.

[4] Based on average natural gas prices from 2017 to 2021 and an 8% rate of return over the lifetime of the measure.

In the APS, methane emissions from oil and gas operations fall to around 45 Mt in 2030 and 20 Mt in 2050. Around half of the methane emissions from oil and gas operations currently occur in countries that have pledged to act on methane, and some of the largest emitters – including Russia, Iran, Turkmenistan and China – have not committed to absolute methane reductions before 2030. In the APS, countries with pledges on methane – including participants in the Global Methane Pledge, endorsers of the Global Methane Pledge Energy Pathway, and countries with specific methane pledges (e.g. Qatar) – are assumed to act on oil and gas methane. Companies with commitments on methane emissions also help tackle some emissions in countries without pledges, including at non-operated assets and through joint ventures (IEA, 2023f).

In the NZE Scenario methane emissions from oil and gas operations fall by more than 75% to 2030. Around 30% of this reduction stems from the drop in oil and gas demand over this period. The other 70% occurs because of targeted efforts to cut methane from oil and gas operations. In other words, even in the NZE Scenario, the reduction in oil and gas demand must be complemented by additional, targeted abatement action on methane to ensure emissions fall at a fast enough pace. Without explicit efforts to tackle methane emissions from fossil fuel supply, global energy-related CO_2 emissions would need to reach net zero by around 2045 – five years earlier than in the NZE Scenario – with important implications for equitable pathways.

In the NZE Scenario, currently available methane abatement technologies are deployed at all oil and gas production, processing and transport facilities by 2030. This means that all oil and gas companies would have an emissions intensity similar to the world's best operators today. Reductions in oil and gas methane emissions to 2030 account for more than 10% of the total reductions in energy-related GHG emissions in the NZE Scenario over this period. Technology improvements after 2030 help to nearly eliminate all non-emergency methane emissions by 2040 and continuous monitoring systems ensure large leaks are prevented and minor ones quickly addressed. The global average methane intensity of natural gas supply falls from around 1.4% in 2022, to 0.5% in 2030 and 0.1% in 2050; for oil the methane emissions intensity falls from 1.3% in 2022, to 0.3% in 2030 and 0.05% in 2050.[5]

Around USD 75 billion of spending is required to 2030 to deploy all methane abatement measures in the oil and gas sector. This is less than 2% of the net income received by the oil and gas industry in 2022. Most measures should be financed by the industry itself, but about USD 15-20 billion may be challenging to mobilise without concessional financing or other means of support. This includes measures to cut emissions in low- and middle-income

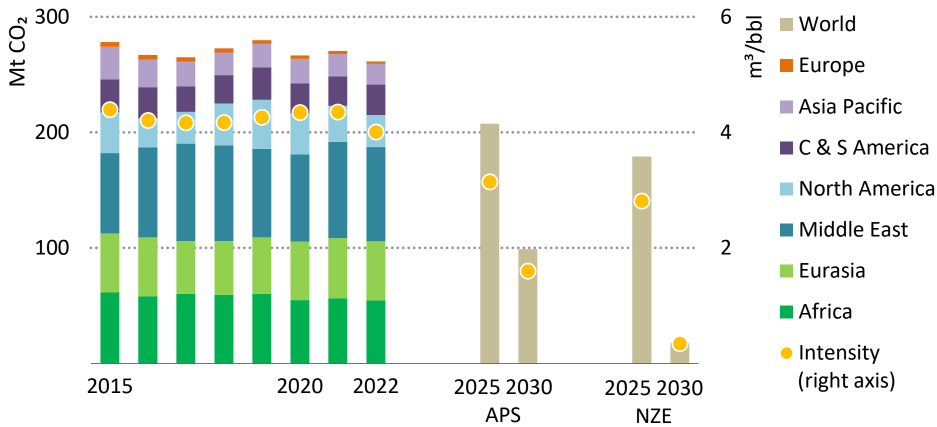
[5] The natural gas methane intensity is calculated here as total methane emissions from natural gas supply (37 Mt in 2022) divided by global marketed natural gas production (144 exajoules [EJ] in 2022), assuming methane has an energy density of 55 megajoules per kilogramme. The oil methane intensity is methane emissions from oil supply (45 Mt in 2022) divided by oil production (189 EJ in 2022). These intensities differ from those reported by some companies and industry organisations, e.g. OGCI (2022), which are upstream oil and gas methane emissions divided by natural gas production in volume terms (equivalent to a global average of about 2.5% today using our estimates).

countries, at facilities owned and operated by national oil companies and smaller independent companies, and for measures that do not generate a meaningful return over their lifetime (IEA, 2023b). This is an appropriate area for focused international action.

Flaring

Around 140 bcm of natural gas was flared in 2022, resulting in nearly 0.5 Gt CO_2-eq of GHG emissions. This includes both CO_2 from the combustion of the gas and NGL contained within the gas stream, plus methane emissions. There should be minimal methane emissions from a flare if it is designed, maintained and operated correctly, but this is not always the case and sometimes flares are totally extinguished, resulting in direct venting to the atmosphere of gas that should be combusted. We estimate that only around 92% of the gas volumes directed into flares around the world are properly combusted (IEA, 2023c).

Figure 2.9 ▷ CO_2 combustion emissions from flaring and flaring intensity in the APS and NZE Scenario, 2010-2030



Flared volumes fall by more than 60% by 2030 in the APS and by about 95% in the NZE Scenario as all non-emergency flaring is eliminated globally.

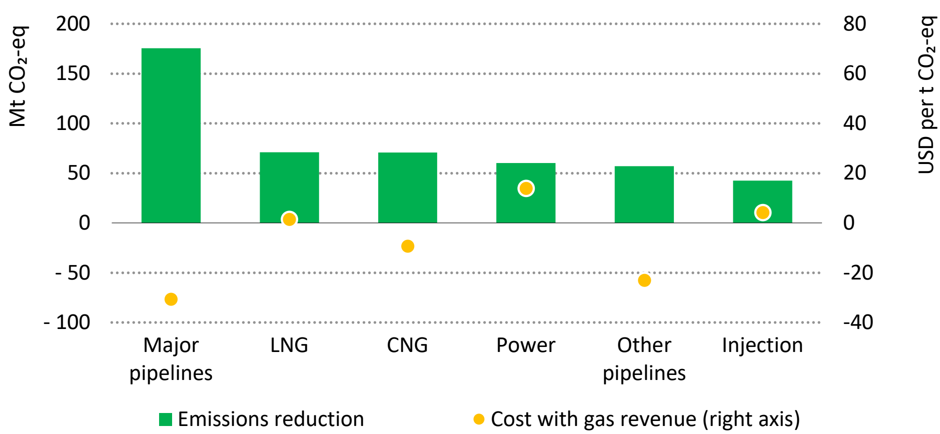
Notes: C & S America = Central and South America; m^3/bbl = cubic metres per barrel.

The Zero Routine Flaring by 2030 Initiative, launched by the World Bank and the United Nations in 2015, commits governments and companies to end routine flaring no later than 2030. There has been some progress since its launch – the amount of gas flared per barrel of oil produced fell by close to 10% in 2022 from 2021 – but the total gas flared globally is still very high.

Nearly 95% of the GHG emissions from flaring are abatable with existing technologies. There are many options to use the natural gas that is currently flared, including bringing it to consumers via a new or existing gas network, reinjecting it to support reservoir pressure, and converting it to LNG, compressed natural gas (CNG), methanol, fertilisers or power with CCUS. Flares can now be monitored every day on a near real-time basis, helping companies to identify bottlenecks and opportunities in operated and non-operated assets. Mobile mini-LNG production equipment can reduce the need for flaring and venting during well testing and other short-term operations. Automated controls can ensure flares operate at optimal levels, reducing the amount of methane that escapes from the combustion process. With the exception of gas injection, gas that is saved can often be resold, depending on local gas markets or the ability to export, significantly lowering the net cost of abatement.

In the APS, flared volumes fall by around 20% to 2025 and by more than 60% to 2030 (Figure 2.9). This is mostly due to flaring reduction projects in countries committed to the Zero Routine Flaring by 2030 Initiative. Action from countries with pledges to curb methane emissions (e.g. Global Methane Pledge) also play a significant role, as incomplete combustion in flares is a leading cause of methane emissions and related mitigation efforts also help reduce flaring volumes. In 2030 flaring remains at high levels in some major producers, such as Russia, and only partial reductions are achieved from levels in 2022 in regions where governments have not pledged to act, but key industry players have (e.g. Algeria).

Figure 2.10 ▷ Emission reduction potential and average cost of flaring reduction measures in the NZE Scenario, 2022



Around two-thirds of emissions from flares could be avoided at no net cost because the value of the captured gas in the NZE Scenario is sufficient to cover the cost of abatement.

Notes: Abatement measures selected according to flare size and distance from existing infrastructure (Omara, et al., 2023). Gas income is based on prices to 2030 in the NZE Scenario. Power projects include CCUS. Major pipelines carry more than 280 000 m³ of gas per day.

Sources: IEA analysis based on data provided by EDF (2022), the World Bank Global Gas Flaring Reduction Partnership (World Bank, 2023), the Methane Guiding Principle's Cost Model (MGP, 2022), and Capterio (Charles & Davis, 2021).

In the NZE Scenario, all non-emergency flaring is eliminated globally by 2030, resulting in a near-95% reduction in flared volumes by 2030. Around USD 70 billion of upfront spending is required up to 2030 to achieve these reductions, but in many cases the value of the captured gas is sufficient to cover the cost of the abatement measure. The most cost-effective solution is to bring the gas to market via new pipeline connections to gas transmission or distribution grids, or to CNG or LNG terminals, and this is where most of the capital expenditure is directed. Close to 90% of emission reduction measures would be cost-effective to deploy in the presence of an emissions price of USD 15/t CO_2-eq and almost all measures would cost less than USD 60/t CO_2-eq to deploy (Figure 2.10). In aggregate, even with the low gas prices seen in the NZE Scenario, the value of the captured gas that could be sold is greater than the amount of spending required to 2030.

Despite the cost-effectiveness of many flaring abatement options, reduction projects can face a number of challenges, including information gaps, institutional barriers and opportunity costs. Policy and enforced regulation play a critical role in reducing flaring; Norway put in place a ban in 1971 and has successfully managed to keep very low levels of flaring despite ongoing production, while Brazil and the United Kingdom impose a cap on flaring and require operators to shut down production if they breach flaring limits.

2.2.4 Boosting efficiency and electrifying oil and gas facilities

The energy required for upstream oil and gas operations in 2022 resulted in more than 700 Mt CO_2 emissions. Around 10% of this total is associated with Canadian oil sands production, which requires significant quantities of natural gas. In more conventional upstream operations, energy is mainly required to power electrical equipment, and the electricity is often produced using small-scale on-site natural gas or diesel generators. Using more efficient equipment – such as swapping an open-cycle gas turbine for combined-cycle – would save around 30% of the energy required. But full electrification would lead to even greater efficiency improvements.

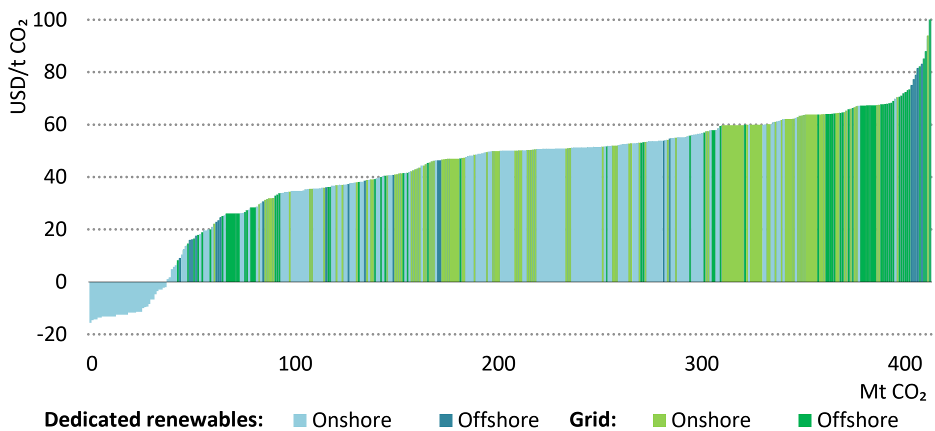
The energy for upstream facilities could be provided by electricity from a centralised grid or generated in a decentralised renewable energy system. Operators face several choices when implementing an electrification programme, including:

- 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).
- Assessing total costs in the context of the capital required to build sufficient 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; several solutions are 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 detailed geospatial analysis to estimate the potential for and costs of electrifying upstream facilities through both of these methods: centralised grid connections vs decentralised renewable systems. We estimate that more than half of global oil and gas production today lies within 10 km of an electricity grid and three-quarters takes place in an area with good wind or solar resources. 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). Grid connections are a viable solution in onshore oil and gas fields that lie relatively close to built-up areas; this is the preferred option in North America and Eurasia. 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 (Figure 2.11).

Figure 2.11 ▷ Cost of electrifying oil and gas production sites



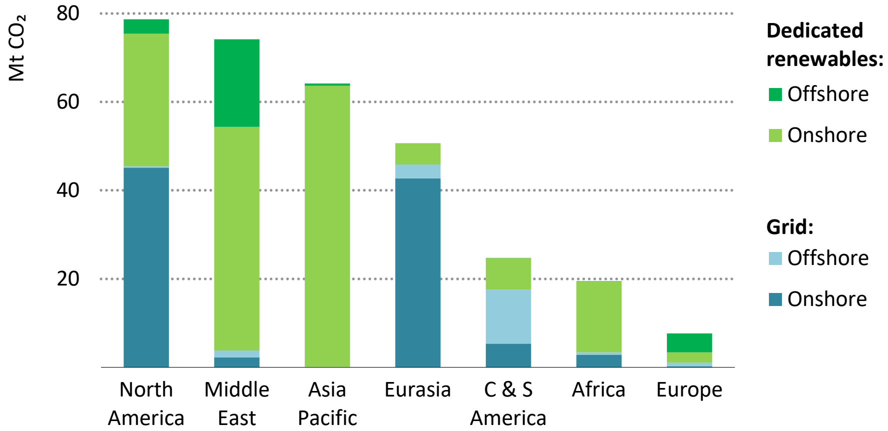
CO_2 emissions from upstream operations could be cut by more than 400 Mt CO_2 – reducing total upstream CO_2 emissions by 60% – by electrifying upstream facilities.

Note: Based on regional natural gas prices to 2030 in the NZE Scenario (USD 2-6 per million British thermal units [MBtu]).

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 collaborated 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.

In the APS, around 150 Mt CO_2 is avoided through electrification in 2030 and 200 Mt CO_2 in 2050. In the NZE Scenario around 320 Mt CO_2 emissions are avoided in 2030 (Figure 2.12). This requires nearly 800 terawatt hours (TWh) of electricity, of which around 60% is supplied through dedicated renewable installations and the remainder from grid connections. By 2040, essentially all oil and gas sites that are still in operation are electrified. On average the cost of electrifying fields in this scenario adds USD 0.35/boe of production.

Figure 2.12 ▷ CO_2 emissions avoided by electrifying upstream oil and gas operations in the NZE Scenario, 2030



Most of the near-term opportunities for electrification come from the construction of dedicated renewable sites.

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

2.2.5 Reducing emissions from refining and LNG facilities

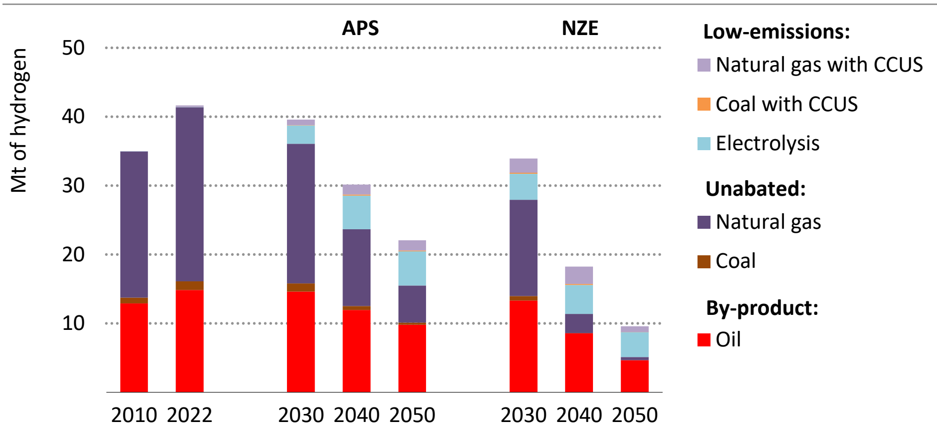
Refineries

Oil refineries caused 1.1 Gt CO_2 emissions in 2022, of which 800 Mt CO_2 was from energy use on-site and 350 Mt CO_2 was from the production of electricity and hydrogen purchased from off-site sources. Emissions arise from processes including catalytic cracking and petroleum coke processing, as well as hydrogen, heat and electricity production. A very small amount of methane emissions also occur during refining (around 0.2% of total GHG emissions from the oil supply chain and 0.5% of GHG emissions from refining operations). The two key mechanisms to cut emissions from refineries are the use of low-emissions hydrogen and CCUS.

The production of hydrogen is one of the major sources of emissions from refineries. Globally around 42 Mt of hydrogen is used to refine and upgrade oil – nearly half of global hydrogen demand today – resulting in around 380 Mt CO_2 annually. Some 20% of the hydrogen consumed in refineries comes from external suppliers. Refineries are well-suited for the deployment of low-emissions hydrogen because they can accommodate a new source of hydrogen without the need for new end-user equipment.[6] Refineries can be "anchor" sources of demand for scaling up low-emissions hydrogen supply, reducing the risks for second-mover applications in the vicinity that face the complexity of synchronising investment in low-emissions hydrogen supply with investment in hydrogen demand technologies.

Some of the largest projects in operation or under construction globally to produce hydrogen from electrolysis are being developed by oil and gas companies or will supply hydrogen to a refinery. This includes a 260 megawatt (MW) electrolyser to produce hydrogen for a refinery in China and a 200 MW electrolyser to replace hydrogen from a natural gas reformer in the Netherlands. Oil and gas companies are involved in more than 300 electrolysis projects already in operation or in development, with an average capacity of just under 1 gigawatts (GW). In addition to the advantages related to their relative ease of integrating low-emissions hydrogen, refineries are often in locations that are well-suited to deploying renewable electricity, reducing the need for new infrastructure.

Figure 2.13 ⊳ Hydrogen use by refineries in the APS and NZE Scenario



Low-emissions hydrogen is deployed at scale in refineries by 2030, and replaces hydrogen from unabated coal and natural gas by 2050.

Notes: CCUS = carbon capture, utilisation and storage. Data includes both hydrogen produced on-site at refineries and that procured from external facilities. By-product hydrogen is produced from other refinery processes, such as catalytic reforming or petrochemical facilities.

[6] Low-emissions hydrogen includes hydrogen produced from water using electricity generated by renewables, nuclear, bioenergy, or fossil fuels equipped with CCUS with a high capture rate (IEA, 2023g). Demand for low-emissions hydrogen includes its use to produce hydrogen-based fuels.

In the APS, total refinery demand for hydrogen is broadly flat to 2030, but an increasing amount comes from low-emissions sources (Figure 2.13). Including hydrogen purchased from off-site sources, around 3 Mt of low-emissions electrolysis hydrogen is used in refineries in 2030, a value that increases moderately to 2050. This requires around 40 GW of electrolyser capacity and around 130 TWh of low-emissions electricity. Refinery hydrogen use declines after 2030 as refinery activity diminishes, and this means the share of low-emissions electrolysis hydrogen in total hydrogen use climbs from very low levels today to 7% in 2030 and more than 20% in 2050.

In the NZE Scenario, around 4 Mt of low-emissions electrolysis hydrogen is used in refineries in 2030. This volume remains stable to 2050 despite the sharp overall decline in hydrogen used in refineries; the share of low-emissions electrolysis hydrogen in overall use climbs from 10% in 2030 to nearly 40% in 2050 (most of the remaining hydrogen used in 2050 comes as a by-product from other refinery processes).

The cost of avoiding one tonne of CO_2 through the use of low-emissions electrolysis hydrogen ranges widely depending on the relative prices of fossil fuels and costs of renewable and nuclear electricity. Costs are lowest in regions where imported natural gas prices are relatively high and renewable electricity costs relatively low, which include India and parts of Latin America. In these regions, the use of low-emissions electrolytic hydrogen in 2030 would add around USD 1.4/bbl to the cost of refining a barrel of oil. In Europe and North America, the costs are less favourable, but would still only add around USD 3/bbl to the cost.

The use of CCUS can also help reduce emissions from refineries. 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 relatively straightforward to capture it. Coal- and natural gas-based hydrogen units can be designed for 95% CO_2 capture or higher 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.

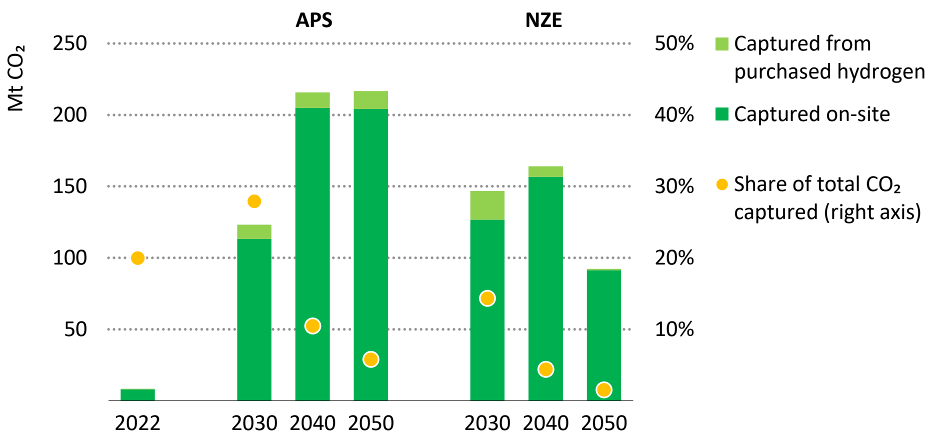
Equipping hydrogen production with CCUS costs USD 25-45/t of CO_2 avoided (for coal) or USD 50-90/t of CO_2 avoided (for natural gas). This would add just USD 0.6-1/bbl to the cost of refining, with costs around twice as high for other onsite CO_2 sources where the size of the individual CO_2 streams are smaller (IEAGHG, 2017). Many refineries are located close to where extracted oil and gas are brought onshore and so are near geology that is potentially well-suited to underground CO_2 storage, lowering the costs of CCUS for refineries compared with other types of facility. It is estimated that some two-thirds of existing refineries are located within 50 km of potential storage for CO_2 (IEA, 2022a).

Learnings from the financing, construction and operation of CCUS for refineries can 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 elsewhere in the economy. The integration of bioenergy represents another opportunity for refiners to make an active contribution to net zero transitions by helping to scale up the cost-effective production of liquid biofuels (see

Section 2.3.3). Some companies are also looking to deepen integration with petrochemical operations, which could offer operational synergies and enhance feedstock flexibility while providing a hedge against a possible peak in demand for road transport fuels.

In the APS, CO_2 captured from refinery-related installations grows from around 8 Mt CO_2 in 2022 to more than 120 Mt CO_2 in 2030 (Figure 2.14). Most is captured on-site at refineries from hydrogen production. Volumes captured rise further to 2040 and then remain around that level given the downward trend in refinery throughput. In total, the use of CCUS and electrolysis hydrogen – alongside other emission reduction measures taken by refiners, including the use of electricity and bioenergy for heat – means the scope 1 and 2 emissions intensity of refining falls from around 35 kg CO_2/boe processed in 2022 to 28 kg CO_2/boe in 2030 and just under 20 kg CO_2/boe in 2050.

Figure 2.14 ▷ CCUS use by refineries and trends in the APS and NZE scenario



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Refineries play a leading role in the deployment of CCUS this decade, helping to launch a global CCUS industry in other sectors, which come to dominate total CO_2 captured by 2050.

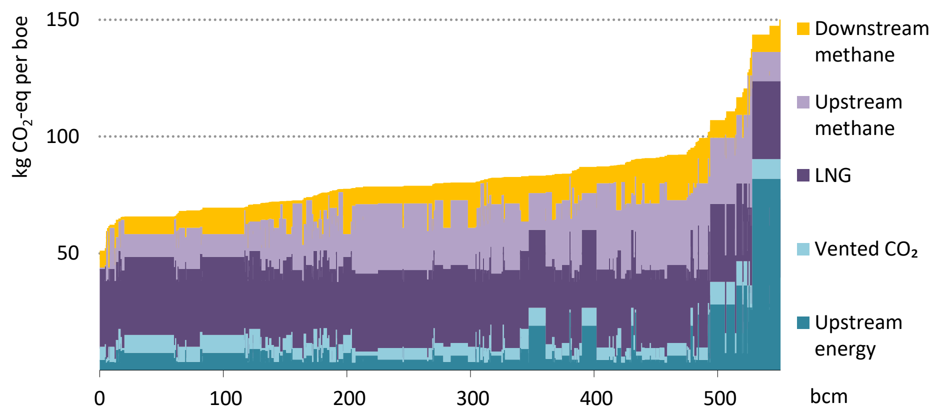
In the NZE Scenario, trends in the use of CCUS in refineries to 2030 are similar to the APS. After 2030 the sharp reduction in refining activity means that the increase in CO_2 captured from refineries also starts to decline. In total, the use of CCUS, low-emissions hydrogen and other emission reduction measures means that the scope 1 and 2 emissions intensity of refining falls to around 23 kg CO_2/boe in 2030 and just over 7 kg CO_2/boe in 2050.

LNG

Liquefying natural gas is an energy-intensive process that emits anywhere in range of 50-150 kg CO_2-eq per boe from extraction of the raw feedgas to delivery to end consumers. Around 40% of this comes from cooling the gas down to -162 °C, a process that is usually powered by consuming a portion of the gas flowing to the (often remote) facility. The amount of gas used in this way varies markedly between facilities, but averages around 10% globally.

The total emissions associated with the LNG value chain – liquefaction, shipping and regasification – are estimated to be around 130 Mt CO_2-eq. Emissions from the upstream feedgas add a further 120 Mt CO_2-eq (Figure 2.15). Upstream methane is in some cases difficult to directly attribute to individual liquefaction facilities, but on average it accounts for around one-third of the overall LNG supply emissions. Another key variable is the CO_2 content of the natural gas feeding the LNG terminal. The typical range is from 5% to 15% CO_2 on a molar basis. Producing LNG requires the removal of this CO_2 to avoid hydrate and freezing issues during liquefaction. This CO_2 is often vented to the atmosphere; we estimate around 20 Mt CO_2 is vented, primarily in the pretreatment phase.

Figure 2.15 ▷ Spectrum of emissions intensity of LNG supply, 2022



The global LNG supply chain emits around 300 MtCO_2-eq. The most energy-intensive part of the process is gas liquefaction, requiring around 10% of the feedgas for export terminals.

A handful of projects globally have made dedicated investments to reduce emissions associated with the LNG value chain, and efforts have also been made to measure the emissions associated with LNG cargoes. The 21 bcm Gorgon LNG facility in Australia and 7 bcm Hammerfest LNG in Norway employ CCUS in the gas processing and pretreatment stages. In the case of Gorgon, the project was designed to capture and inject around 4 Mt CO_2 per year, but issues around the presence of sand in the facility have resulted in lower injection rates. Although there are no projects in operation today that use CCUS to reduce emissions from liquefaction, Qatar has announced a plan to fit CO_2 capture on ten of its liquefaction trains, with the aim of capturing around 4 Mt CO_2 per year. Costs would vary by project scale and experience, but would likely average around USD 60/t CO_2 avoided, which would translate into an increase of around USD 0.25/MBtu in the cost of the liquefaction process (around a 20% increase in costs) (IEAGHG, 2019).

Another way to lower emissions from LNG is to electrify the liquefaction process. Traditional natural gas liquefaction processes use gas turbines or internal combustion engines to drive the liquefaction refrigeration cycle. Electrification involves replacing these with electric motors, and these can be powered either by low-emissions electricity from the grid or dedicated renewable installations backed by batteries or thermal back-up power. A handful of projects have been pursued in this space, such as Freeport LNG in the United States, LNG Canada, Hammerfest LNG in Norway and Curtis Island in Australia, albeit with mixed levels of implementation success to date.

Through a detailed geospatial assessment of proximity to nearby electricity infrastructure and solar and wind potential, we estimate that 60% of the world's LNG export terminals in operation in 2030 in the NZE Scenario can be electrified, at a total cost of around USD 20 billion. This would avoid around 70 Mt CO_2 and would add around USD 0.60/MBtu to the delivered cost of the LNG. Another option proposed to align LNG plants with net zero transitions is to convert them to be hydrogen-ready (Box 2.1).

Box 2.1 ▹ Can LNG infrastructure be hydrogen-ready?

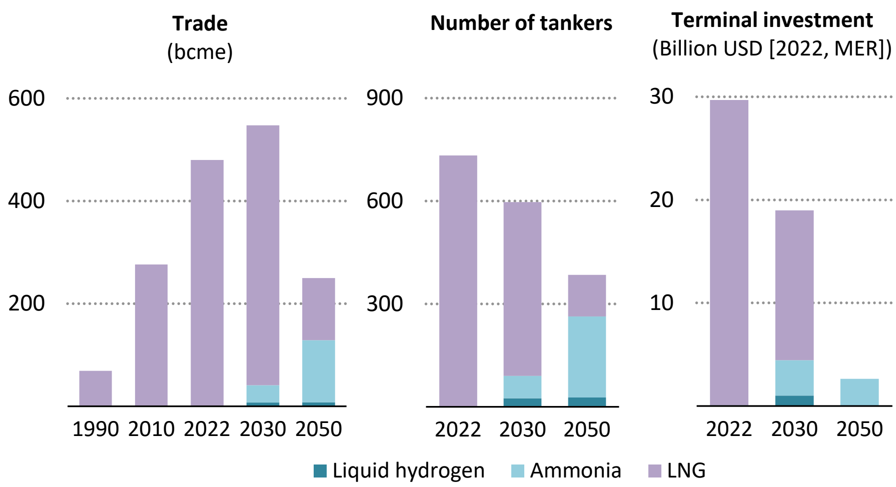
The energy crisis precipitated by Russian cuts to gas deliveries to Europe incentivised investment in non-Russian supplies, new trade infrastructure – notably for LNG – and alternatives to natural gas. But with the future of natural gas unclear in regions with strong climate policies, such as Europe, companies have been searching for other ways to future-proof natural gas infrastructure, including making the assets ready for a transition to hydrogen at a later date.

In the NZE Scenario, LNG trade in 2030 is around 1 EJ lower than in 2022, while trade in hydrogen and hydrogen-based fuels increases to 2 EJ (90 bcm equivalent [bcme]) (Figure 2.16). To understand whether investments can bridge from one fuel to another and thus retain economic value into the 2030s, analysts have set to work on what "hydrogen-ready" – an as-yet undefined term – could mean for LNG in practice.

The liquefaction technology used for LNG is not reusable for hydrogen. If hydrogen were to be transported in liquid form, it would have to be cooled to -253 °C, around 100 °C colder than for natural gas. The cooling systems, storage facilities and tankers could potentially be augmented from the outset to be compatible with these lower temperatures – with special thermal insulation to minimise high boil-off rates during storage – but even with this additional investment, which would be considerable, the pumps and valves are likely to need replacing before transitioning to hydrogen.

The energy that can be exported through hydrogen liquefaction is lower than for natural gas. Hydrogen liquefaction requires 20-30% of the input energy, compared with around 10% for LNG. In addition, liquefied hydrogen has a lower energy density, meaning that the same sized storage facilities and ships can each hold less energy. Converting LNG facilities to hydrogen facilities could benefit from the port infrastructure, brownfield site and connections to energy networks, but there are likely to be few synergies between some of the most capital-intensive equipment. There also may not be a perfect overlap between the location of LNG liquefaction terminals and the availability of low-cost renewable electricity to produce low-emissions electrolytic hydrogen.

Figure 2.16 ▹ Key indicators for hydrogen, selected hydrogen-based fuels and LNG trade in the NZE Scenario



The lower energy density of hydrogen means more ships are required to ship the same energy content carried in LNG vessels.

Note: bcme = billion cubic metres equivalent.

If hydrogen were converted to ammonia for transport, more of the existing LNG infrastructure might be reusable. Ammonia has an energy density closer to that of LNG and an ammonia-ready LNG import terminal is estimated to be just 7-12% more expensive than a conventional LNG import terminal, well within the range of historical average cost overruns (IEA, 2022b). Another option is to the spread cost by constructing shared LNG and ammonia terminals, and this has been proposed, for example in Germany. Whether operators will find a business case for converting the ammonia back to hydrogen at the import site remains subject to tests of the technology in coming years.

A third possibility is to convert the hydrogen to synthetic methane or construct pipelines to gather large volumes of biomethane, both of which can then use the existing LNG infrastructure without modification. A source of carbon is needed, which could add considerable cost: in the NZE Scenario, low-emissions synthetic fuels are exclusively made with carbon recovered from CO_2 captured from bioenergy or the air.

In all cases, the environmental benefits will hinge on avoiding any escape of methane into the atmosphere along the value chain.

Repurposing gas pipelines

Existing gas pipeline infrastructure can potentially be repurposed or reused to fast-track the deployment of CO_2 or hydrogen infrastructure, reducing lead times and the amount and cost of new infrastructure that would need to be built. Repurposing can lower a project's overall environmental footprint by reducing material demand, and it can help infrastructure owners maximise the economic lifetime of their assets while reducing or deferring decommissioning costs.

Hydrogen blends of up to 20% by volume (6% in energy terms) can be achieved with minimal modifications to gas pipelines, depending on their material composition. Fully converting gas pipelines to transport hydrogen is a more complex process; to operate a repurposed pipeline at its full design capacity, volumetric flows of hydrogen would need to be three times higher due to the lower volumetric density of hydrogen compared to natural gas. This would require more powerful and costly compressors. But it may nonetheless be cost-competitive against building new, dedicated hydrogen infrastructure, cutting investment costs by 50-80% relative to building new lines (IEA, 2023h).

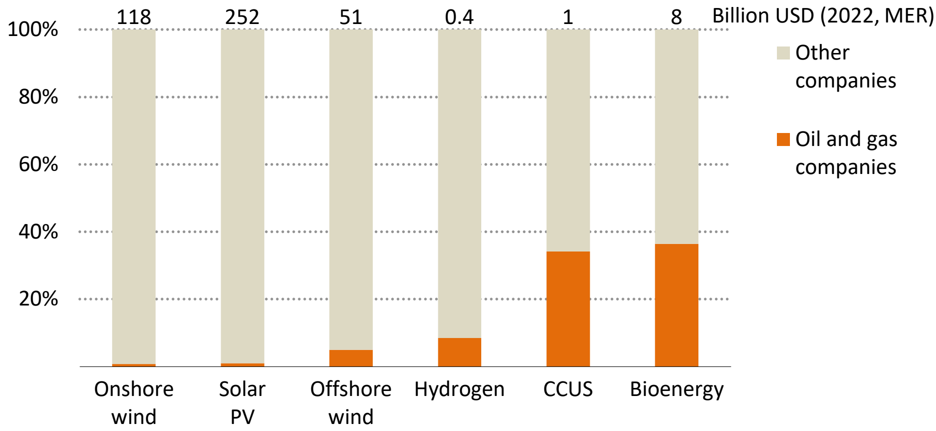
Gas pipelines may also be used to carry CO_2, with existing and under-development projects in the United Kingdom, the Netherlands and the United States. Screening pipelines for their strength and pressure rating, alongside other integrity tests, would be essential to establish their potential for safely transporting CO_2.

2.3 New technology options

The oil and gas industry has invested in a broad range of clean energy technologies in recent years (Figure 2.17). Capital flows towards them have, to date, been small relative to overall capital expenditure by the industry, but have been motivated as a hedge against possible future declines in oil and gas demand, as an opportunity to grow new business areas in the emerging energy economy, and to comply with policies and regulations that limit the emissions intensity of energy supplied to the market.

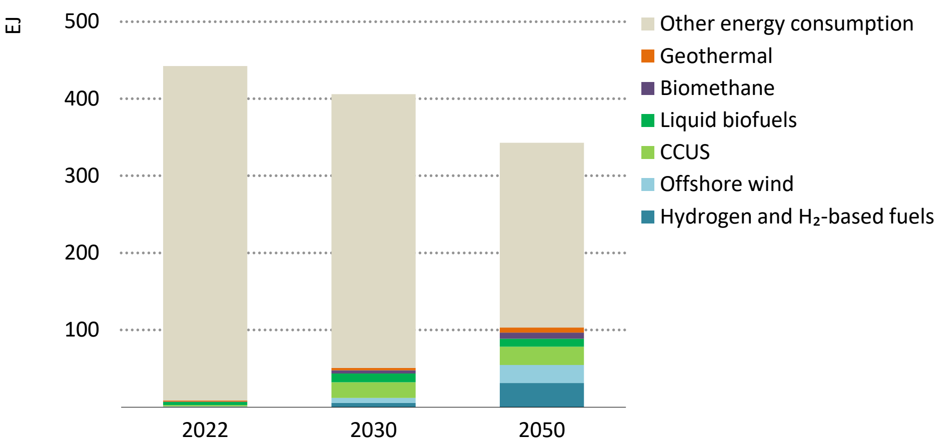
A number of clean energy technologies have a close affinity with existing skills and resources in the oil and gas industry. They include technologies that can make use of the industry's know-how in handling liquids and gases, large financial resources, extensive research and development expertise, technical and operational knowledge (especially of subsurface and drilling and offshore infrastructure), and proficiency in executing and managing multi-billion dollar projects. Many of the technologies can also take advantage of existing transmission and distribution infrastructure for oil and gas. Options include CCUS, low-emissions hydrogen and hydrogen-based fuels, offshore wind, geothermal, bioenergy, plastics recycling and electric vehicle (EV) charging. These technologies can play a central role in helping to tackle emissions from some of the hardest-to-abate sectors and they provide or address nearly 30% of total final energy consumption in the NZE Scenario in 2050 (Figure 2.18). These technologies also provide a large investment opportunity, reaching USD 350 billion in 2030 in the APS and more than USD 500 billion in the NZE Scenario (Figure 2.19).

Figure 2.17 ⊳ Average annual investment in clean energy technologies, 2019-2022



Oil and gas companies provide a notable share of total investment in certain clean energy technologies – especially CCUS and bioenergy – but overall spending levels are still low.

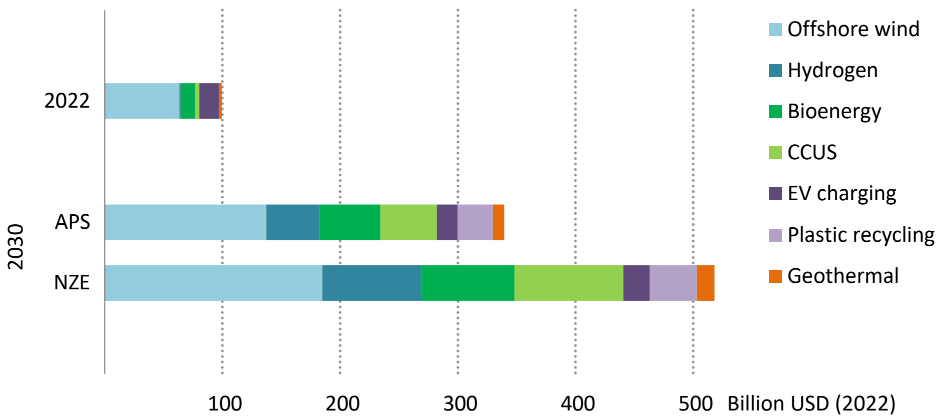
Figure 2.18 ⊳ Final energy consumption met using one or more of the new technology options in the NZE Scenario, 2022-2050



Companies engaged in clean energy technology areas that draw upon oil and gas industry strengths could provide or address 30% of all energy consumed in 2050.

Notes: H_2 = low-emissions hydrogen. Where the final energy product is supplied via more than one technology options – such as offshore wind electricity that feeds electrolysis for hydrogen or CCUS-equipped hydrogen production – it is allocated equally between the categories. Excludes EV charging.

Figure 2.19 ⊳ Annual investment in technologies that share synergies with the skills and expertise of the oil and gas industry



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There is a USD 350-500 billion annual investment opportunity in clean energy technologies in 2030 that are suited to the skills and expertise of the oil and gas industry.

None of these technologies are a perfect fit for all companies and they can demonstrate important differences from traditional oil and gas operations. One area that is often cited is the returns on capital invested (Box 2.2). Some National Oil Companies may not have a mandate to move beyond traditional operations. Other factors inside oil and gas companies may also hinder the development of clean energy activities, including limited managerial bandwidth to operate both legacy businesses and new activities. If oil and gas companies choose not to be involved in the deployment of these technologies, this does not mean that they will not be successfully deployed, but it may take much longer for them to reach the level of maturity where they can be supplied cost-competitively.

The remainder of this section looks in detail at each of these technologies, including the role of the oil and gas sector to date, what happens to the technology in the APS and NZE Scenario, and how it matches or differs from the skills and expertise of the oil and gas industry.

Box 2.2 ⊳ Returns on capital for traditional oil and gas and clean energy

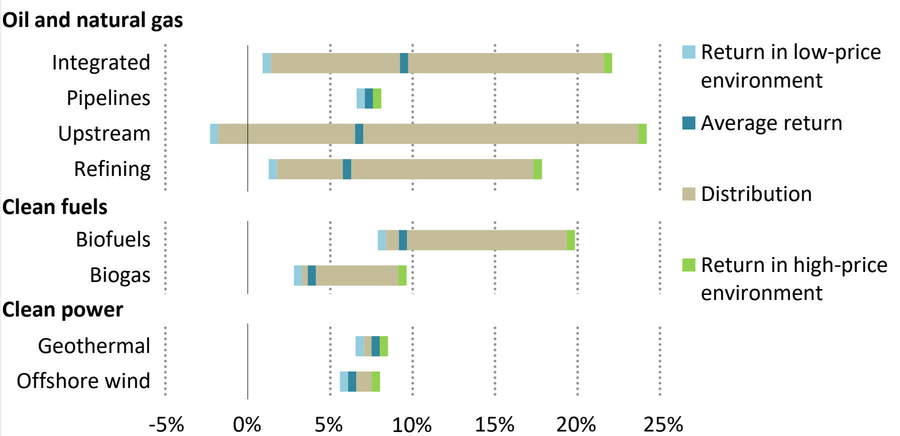
A key consideration for any oil and gas company looking to develop new business areas is in the anticipated returns, especially compared with returns from traditional operations. Returns depend on factors such as geographical location and sales market, and vary between different types of companies (e.g. the majors and independents), but we estimate that the return on capital employed (ROCE) in the oil and gas industry averaged 6-9% between 2010 and 2022. Integrated companies tend to appear towards the upper end of this range and refiners towards the lower end (Figure 2.20).

The average ROCE masks a high degree of variability for individual years. For example, in a high-price year (e.g. 2022), integrated and upstream pure players made as much as 20-25%, and in a lower-price year (e.g. 2016) they saw returns fall close to zero or below. Pipeline operators tend to see a more stable ROCE due to the regulatory environment in which they typically operate.

Most of the clean energy technology investments have delivered returns of around 6% since 2010. Some exhibit a similar volatility and sensitivity to fuel prices – very high in some years and very low or negative in others – and can reach double-digit ROCE in certain years. However, other technologies – such as offshore wind and geothermal – see less annual variation in the ROCE, with stable returns due to long-term contracts and greater revenue certainty.

Renewables projects with fixed offtakers tend to have lower volatility in returns than oil and gas projects and they also generally have a lower risk profile. Shareholders in oil and gas companies that are accustomed to high – and volatile – returns may therefore struggle with the different profile of clean energy technologies.

Figure 2.20 ▷ Return on capital employed for selected oil and gas and clean energy businesses, 2010-2022



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Investment opportunities in clean energy can yield average returns that are similar to those of the oil and gas industry and, for clean power, are much less volatile.

Notes: Return on capital employed is a measure of the efficiency with which capital (assets minus current liabilities) is employed. "High-price environment" is data for 2022 (oil price above USD 95/bbl and imported natural gas prices above USD 15/Mbtu); "low-price environment" is data for 2016 (oil price below USD 50/bbl and imported natural gas prices around USD 6/Mbtu). For clean power technologies, the "high price environment" is data for 2014 and "low price environment" for 2020.

Source: IEA analysis of a sample 800 companies from 2010 to 2022 based on data from S&P Global (2023).

2.3.1 Carbon capture, utilisation and storage

CCUS is an essential technology for achieving net zero emissions. It prevents emissions in situations where non-fossil alternatives are particularly costly, such as cement manufacture and petrochemicals, and allows for CO_2 removals and it delivers just under 10% of the cumulative CO_2 emissions savings from 2022 to 2050 in the NZE Scenario. Deploying CCUS at the necessary pace and scale will be contingent upon action by governments, regulators and other stakeholders to ensure sufficient value is attached to avoiding and removing CO_2 emissions and delivering low-emissions products. The oil and gas industry can also play a critical role in assuring the future success of all types of CCUS due to its uniquely relevant expertise, project management skills and geological assets.

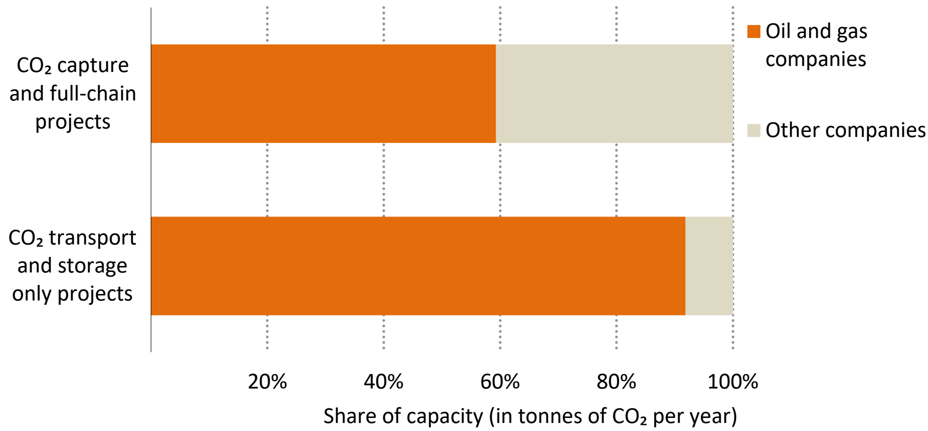
The oil and gas industry has been at the heart of CCUS development globally to date. It is an investor or project partner in more than 90% of CCUS capacity in operation around the world and more than 40% of CCUS investment since 2010 has been in projects directly related to oil and gas value chains. Around 45 Mt CO_2 per year is currently captured via CCUS in 11 countries and injected deep below the earth's surface. Around three-quarters of this CO_2 is injected for enhanced oil recovery (EOR), which is commonly operated without the level of monitoring that is normally associated with CCUS to confirm that the CO_2 has been permanently stored. Of the total, around 30 Mt per year is captured from natural gas processing, mostly in the United States, Brazil, Australia, the Middle East and China, while refinery and upgrader facilities in Canada and the United States capture around 3 Mt CO_2 per year.

Following several recent investment decisions, annual spending on CCUS projects reached a new high of more than USD 3 billion in 2022. The oil and gas industry is heavily involved in these new projects, including nearly 60% of all announced CCUS "full-chain" project capacity involving CO_2 capture and over 90% of that for independent CO_2 transport and storage infrastructure (Figure 2.21). However, just 5% of these projects (representing just over 10 Mt CO_2 per year of capture and 20 Mt CO_2 per year of storage) have taken a final investment decision (FID) so far. There have also been a number of major recent mergers and acquisitions, including Occidental Petroleum's purchase in August 2023 of direct air capture (DAC) company Carbon Engineering and ExxonMobil's acquisition in July 2023 of Denbury, owner of 2 000 km of US CO_2 pipeline capacity and CO_2-EOR operator since the 1990s. In the NZE Scenario, the vast majority of proposed projects would not use the CO_2 for EOR but would instead use dedicated CO_2 storage resources.

CCUS has many crossovers with the existing skills and expertise of the oil and gas industry. The full CCUS supply chain requires the development of geological CO_2 storage resources, operating above-ground CO_2 handling facilities, monitoring gases in the subsurface, and executing complex engineering projects of the type that are almost exclusively carried out by oil and gas companies.

Once established, CO_2 transport and storage assets can provide their owners with significant revenue and this can contribute to oil and gas company portfolio diversification. Since 2015, however, investment by the oil and gas sector in CCUS has represented just 8% of its clean energy capital investment and 0.1% of its upstream oil and gas investment (IEA, 2023i). In some areas of CCUS, such as its integration into cement and steel production, technological risk can still present a barrier to investment. However, major oil and gas companies have publicly stated that the technological risks of CCUS for their own operations are minimal and that economic risks related to CO_2 storage are manageable.

Figure 2.21 ▷ Share of operational and announced CCUS projects to 2030 that has oil and gas company involvement



Oil and gas firms are partners in CCUS projects representing around 70% of existing and planned capacity, with more involvement in transport and storage than capture projects.

Notes: Oil and gas companies include specialist service providers and natural gas network operators. "Involvement" includes project partners and key known suppliers. Includes only CCUS projects targeting operation by 2030, and excludes projects developing CO_2 transport assets to minimise double-counting.

Apart from CO_2 capture for EOR, the business case for CCUS to reduce CO_2 emissions depends largely on government policies.[7] To date, incentives have generally been insufficient for investors to take on projects that are typically large and involve multiple partners building major new pieces of connected infrastructure. There are, however, also signs of a growing constituency of industrial customers that are willing to pay a premium for products made at CCUS-equipped facilities, including low-emissions ammonia, to meet their environmental performance commitments.

[7] CCUS includes processes that convert captured CO_2 into consumer products such as chemicals and fuels. To reduce fossil fuel use in non-durable materials, industrial firms could explore CO_2 utilisation as a source of carbon. In the NZE Scenario, CO_2 utilisation is mainly the use of DAC and biogenic CO_2 in aviation and marine fuel, which do not require additional CO_2 removals to compensate for residual emissions from captured fossil (or limestone-derived) CO_2.

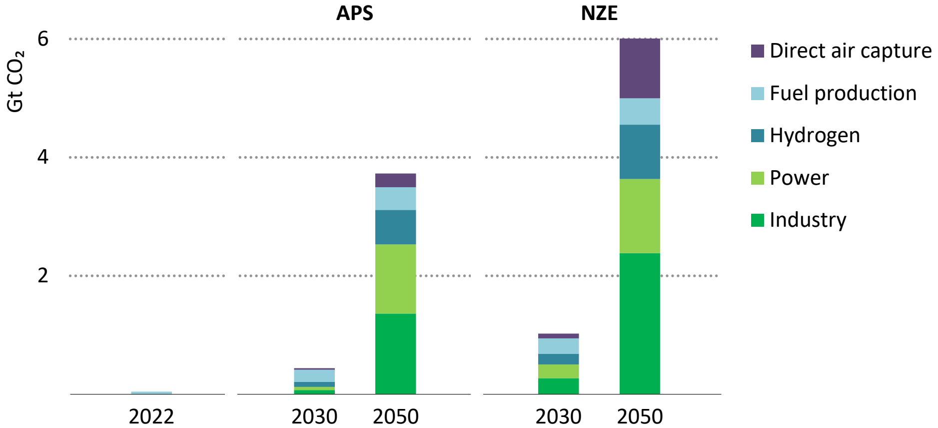
Table 2.1 ⊳ Policy measures that incentivise CCUS investment

Policy type	Examples	Sector in which the example has triggered private investment	Who pays?
Penalties for polluting	Norwegian offshore CO_2 tax (1991)	Natural gas processing	Natural gas buyers
Prohibition of pollution or emissions intensity standard	Western Australia Ministerial Statement 800 (2009)	Natural gas processing	LNG buyers
	Brazilian licence for Santos Basin oil and gas (2014)	Natural gas processing	Oil buyers
	California Low Carbon Fuel Standard CCS Protocol (2018)	None to date	Fuel buyers
Payments for CO_2 capture or storage	US 45Q tax credit (2008, 2018, 2022)	Bioethanol	Taxpayers
	Danish CCUS Funds (2021)	Biomass cogeneration	Taxpayers
Payments for low-emissions production	Dutch SDE++ system (2020)	None to date	Taxpayers
	US 45V Hydrogen Production Tax Credit (2022)	None to date	Taxpayers
	UK Dispatchable Power Agreement, Industrial CCUS and Low Carbon Hydrogen contracts (proposed)	None to date	Taxpayers or ratepayers
CO_2 storage capacity mandates	EU Net Zero Industry Act (proposed)	None to date	Fuel buyers

Three types of climate policy have successfully triggered CCUS investments, and two others may soon be tested (Table 2.1). Other projects have mostly proceeded with government grants for one-off installations, with public spending justified as being in the "public good" and to compensate for the higher risk of demonstration projects. Achieving the deployment rates in the APS and NZE Scenario will require more policies of these types to be developed quickly, complemented by effective regulations, administrative capacity, workforce training and contractual arrangements between businesses in the value chain.

Prospects for CCUS are best when the CO_2 is already in a highly concentrated stream and located close to large CO_2 storage developments. The land requirements for CCUS are smaller than for many low-emissions technologies, particularly where CO_2 pipeline distances are minimised. In both the APS and the NZE Scenario, the oil and gas industry increasingly uses CCUS to avoid the 125 Mt CO_2 that it routinely captures and vents after purifying extracted hydrocarbons (see Section 2.2).

Figure 2.22 ▷ CO_2 capture in the APS and NZE Scenario by source



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To reach net zero emissions globally, industrial processes become the largest source of captured CO_2 after 2030, followed by power generation and hydrogen production.

In the APS, CO_2 capture grows from around 45 Mt CO_2 in 2022 to 440 Mt CO_2 in 2030 (Figure 2.22). The use of CO_2 capture in fuel supply chains – natural gas processing, oil refining and liquid biofuels – remains the largest source through to 2030 and this ensures that the emissions intensity of oil and gas supplies remains compatible with climate goals during the transition. However, the share of CCUS related to fuel supply declines from 85% today to half of the total by 2030. Early action and deployment of large-scale CCUS infrastructure in fuel supply to 2030 is needed so that CCUS is a viable option in other sectors where it is a necessary abatement option after 2030. Building on the investment up to 2030, CO_2 capture rises to more than 3.5 Gt CO_2 globally in 2050.

In the NZE Scenario, CO_2 capture grows to 1 Gt CO_2 in 2030. Around one-quarter of this is related to CO_2 capture in fuel supply, partly due to a large increase in CCUS for merchant hydrogen production, just under 10% of which is purchased by refineries. Achieving this level of CCUS deployment requires around USD 500 billion of investment through to 2030. This investment continues to provide emission reductions after 2030 across multiple sectors, but the nature of the CCUS business is likely to shift. Oil and gas companies operating integrated CO_2 value chains that abate emissions from refineries or hydrogen production in 2030 may give way to dedicated CO_2 transport and storage operators licensed to manage the captured CO_2 from a wider range of sectors and from the atmosphere. By 2050, 6 Gt CO_2 is captured, more than half of which is DAC and from heavy industry, substantially less than in many other 1.5 °C scenarios assessed by the Intergovernmental Panel on Climate Change (Box 2.3).

For the oil and gas industry, engagement with CCUS needs to go beyond thinking of it as a means of securing a "social licence to operate", whereby CCUS is used mainly as an option to reduce or compensate scope 1 and 2 CO_2 emissions. Such an approach is unlikely to support the steady scale-up of investment in successive projects. Rather, the sizeable balance sheets of many oil and gas companies give them a competitive advantage to invest in CCUS across the energy economy. Forward-looking companies could lead the way by advocating policies to help support their efforts to increase capital expenditure in this area.

CCUS offers a very different business proposition than traditional oil and gas operations, which could pose problems for companies seeking to incubate a CCUS division within a larger oil and gas business. The revenue from operating CO_2 transport and storage infrastructure, possibly for a fixed tariff, is likely to be lower and subject to a risk profile more often associated with pension and infrastructure funds than oil and gas commodities.

Policies that underpin widespread CCUS uptake tend to overlap with policies that reduce oil and gas demand. Even so, as CCUS scales up it will compete for a time with oil and gas projects for skills, goods and services, and this could drive cost inflation if not well-managed. To temper cost upswings and risks that CO_2 storage developers are outbid, governments can work to increase the supply of skilled personnel and manage the transformation of depleted hydrocarbon reservoirs into CO_2 storage sites (IEA, 2015). Resolving these various tensions may prove central to scaling up CCUS.

Box 2.3 ⊳ Direct air capture and CO_2 removals in the NZE Scenario

CCUS can remove CO_2 from the atmosphere when storage is paired with direct air capture (DAC) or CO_2 capture from bioenergy (bioenergy with carbon capture and storage [BECCS]). The NZE Scenario sees around 1.7 Gt CO_2 removals in 2050, of which one-third is achieved through DAC. This level of deployment is lower than in other comparable 1.5 °C scenarios, which are in the range of 3.5-16 Gt CO_2 in 2050 (IEA, 2021b).

For countries with low-cost energy and adequate CO_2 storage resources, DAC represents a major potential export opportunity. Countries deploying DAC could expect to receive a payment for any removals beyond those needed to meet their own long-term climate goals. In the NZE Scenario, this market could be worth USD 60-150 billion per year if certificates were to trade at USD 100-250 per t CO_2.

CO_2 removal via DAC is not an unlimited resource, and the level of DAC in the NZE Scenario is likely to be close to the upper bound of what is practicable by 2050. It is constrained by factors including accessible annual CO_2 storage capacity, the available space for the energy inputs (which tend to be renewables), competition for DAC CO_2 from synthetic fuel production, and the price that buyers are willing to pay (IEA, 2022c). The energy requirements and costs of DAC are also substantial and there are good reasons to safeguard its use to compensate for the hardest-to-abate emissions. The NZE Scenario requires around USD 70 billion average annual investment in DAC to 2050 and around 500 TWh of annual electricity generation in 2050 (equivalent to Canada's electricity demand in 2022).

Some producers have argued that levels of oil and gas demand much higher than those seen in the NZE Scenario could be consistent with achieving net zero emissions by 2050 by deploying much greater levels of CCUS and DAC. The difficulties in doing this should not be underestimated.

If oil and natural gas consumption were to evolve as in the STEPS (i.e. with 97 mb/d oil and 4 200 bcm gas consumption in 2050), this would require 32 Gt CO_2 of CCUS by 2050, including 23 Gt CO_2 of DAC, to achieve net zero emissions in 2050 and limit the temperature rise to 1.5 °C.[8] The DAC would require around 26 000 TWh of electricity to operate, more than global electricity demand in 2022. Deploying this level of CCUS and DAC would require USD 3.7 trillion of annual average investment through to 2050 (including the cost of the low-emissions power needed by the DAC facilities), even assuming major cost reductions in CCUS and DAC from current levels. The STEPS requires around USD 3.2 trillion average annual investment in fossil fuel supply and clean energy through to 2050, and so annual investment required to limit the temperature rise to 1.5 °C in this way would be USD 6.9 trillion. This is 50% greater than annual average energy-sector investment in the NZE Scenario.

DAC is untested at this scale of deployment and relying on it to limit the temperature rise to 1.5 °C would be extremely risky. The NZE Scenario is not the only pathway to net zero emissions by 2050, but reducing emissions by phasing down fossil fuel use remains the most technically feasible, cost-effective and socially acceptable way to achieve this goal.

2.3.2 Low-emissions hydrogen and hydrogen-based fuels

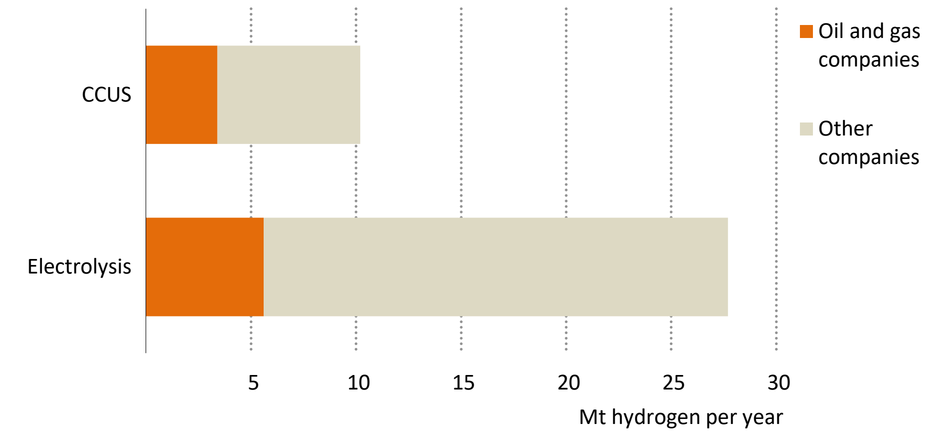
The oil and gas industry is already a major producer and consumer of hydrogen. Around 43 Mt of hydrogen is currently used to refine and upgrade oil per year, nearly half of global hydrogen demand. Low-emissions hydrogen is one of the main pathways for cutting fossil fuel use in heavy industry. Low-emissions hydrogen-based fuels (also known as synthetic fuels) are critical to decarbonising long-distance transport and are an important part of the future of liquid fuels in net zero transitions. Scaling up the production of low-emissions hydrogen and hydrogen-based fuels will require the skills, equipment and resources that give oil and gas suppliers, including producer economies, a competitive advantage.

Investment in low-emissions hydrogen supply projects has been growing exponentially in recent years. This includes production via electrolysis using renewable or nuclear electricity, and from fossil fuels with CCUS. In 2022, spending on electrolyser installations was nearly USD 0.6 billion, double the level in 2021. The world's largest electrolyser project in January 2021 was 25 MW; this was dwarfed by a 150 MW facility in late 2021, and then a 260 MW plant in 2023, both in China. It stands to be overtaken again in 2026 by a 2 GW electrolyser

[8] This level of DAC is required both to offset continued oil and gas use in 2050 and to draw down CO_2 emissions released prior to 2050 as the CO_2 removal technology ramps up.

being built in Saudi Arabia. Meanwhile, investors took FID for two projects to make hydrogen from natural gas equipped with high rates of CCUS in 2022, with the aim for them to be operational by 2025. These facilities, in the United States and Canada, have planned capacities equivalent to 0.8 GW and 0.6 GW of electrolysis running 90% of the time, and should capture 90% and 95% of their CO_2.

Figure 2.23 ▷ Share of low-emissions hydrogen project pipeline to 2030 that has oil and gas company involvement, by anticipated output



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Oil and gas firms are partners in one-third of low-emissions hydrogen production involving CCUS and around 20% of electrolysis operational and planned projects.

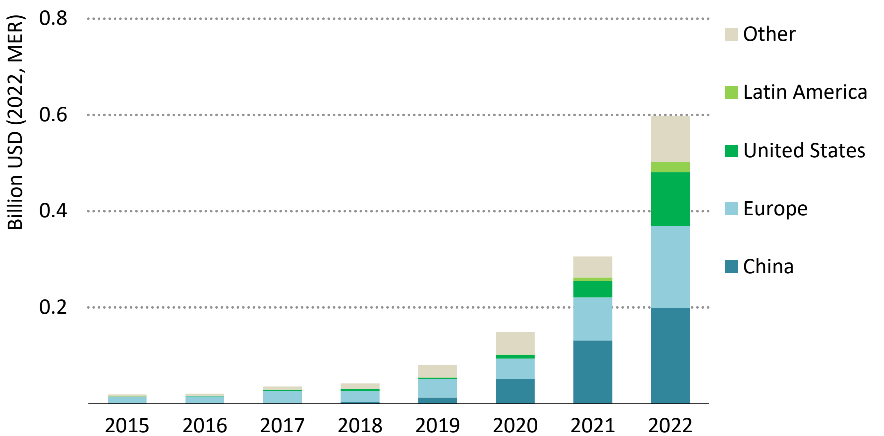
Notes: Oil and gas companies include specialist service providers and natural gas network operators. Output estimates based on announced targets or assumed capacity factors.

Oil or gas companies are partners in one-third of the estimated low-emissions hydrogen output from operational or planned projects applying CCUS, and they are partners in 20% of projects based on electrolysis (Figure 2.23). One rationale for the involvement of these companies in the wider hydrogen sector is to transition their fuel supply businesses from fossil fuels to clean fuels. This could be particularly attractive for producer economies seeking to diversify revenue and reduce reliance on a shrinking market for fossil fuel exports. A vision of continuity is emerging among some producers, based on ample reserves of natural gas, plenty of options for geological storage of CO_2, and outstanding potential for renewables to produce hydrogen by electrolysis (IEA, 2023j).

The capabilities required for large-scale, capital-intensive hydrogen and hydrogen-based fuel developments play to the strengths of oil and gas companies. Developing hydrogen infrastructure involves specialist engineering, complex project management and the highest safety standards. In addition, large-scale production of hydrogen is fundamental to the manufacture of low-emissions hydrogen-based fuels, such as synthetic kerosene, that require the same infrastructure and management as those for crude oil. Not only do oil and gas companies have these skills, but they also have extensive experience with handling industrial volumes of CO_2 and hydrogen, which, like methane, must be tightly controlled to avoid leaks.

Investment in hydrogen supply is driven by government policy, and major public funding initiatives have been launched in recent years. Policy interest in hydrogen has increased considerably since the pandemic and the energy crisis, with greater ambitions to promote domestic energy supply chains. Total annual spending has grown to USD 1.1 billion per year, including USD 0.5 billion on CCUS and USD 0.6 billion on electrolysis projects (Figure 2.24). While much of the funding has been directed to individual supply projects, there are examples of support to other parts of the value chain, such as hydrogen pipelines, storage and electrolyser manufacturing, as well as more generic fiscal and regulatory support.

Figure 2.24 ▷ Investment in electrolysis projects for hydrogen, 2015-2022

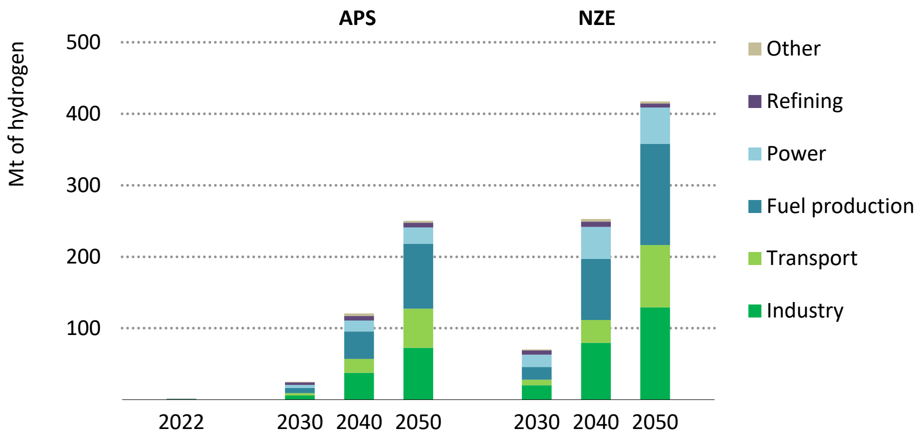


Spending on electrolysis projects is growing fast, but USD 500 billion of cumulative investment in low-emissions hydrogen supply is needed to 2030 in the NZE Scenario.

In the APS, climate policies act to increase low-emissions hydrogen demand. Demand for low-emissions hydrogen grows from less than 1 Mt to 24 Mt in 2030 and it passes today's total hydrogen demand from fossil fuels (95 Mt) just before 2040 (Figure 2.25).

In the NZE Scenario, the demand for low-emissions hydrogen rises to 70 Mt in 2030 and 415 Mt in the 2050. In 2030, half of the demand for low-emissions hydrogen is for transport fuels – whether for use in refining, upgrading biofuels, fuel cell vehicles or conversion to hydrogen-based fuels. In 2050 the two main sources of demand – industry and low-emissions hydrogen-based fuel production – represent similar volumes of hydrogen, with transport demand for low-emissions hydrogen at a slightly lower level. As an example of how important hydrogen-based fuels become to the continued use of oil and gas infrastructure, synthetic kerosene represents over one-third of all energy used for aviation in 2050 in the NZE Scenario. To meet this demand, low-emissions hydrogen production ramps up in all regions according to resource availability, falling capital costs and the costs of transporting hydrogen-based products, such as ammonia, to demand centres. As a result, Australia, the Middle East and North Africa become leading hydrogen producers at levels well above their domestic demand, providing them with the opportunity to move downstream into hydrogen-based products including ammonia or even iron or steel.

Figure 2.25 ▷ Demand for low-emissions hydrogen by sector in the APS and NZE Scenario



Annual demand for low-emissions hydrogen is 415 Mt by 2050 in the NZE Scenario, requiring a rapid scale-up from today's levels, mostly to supply industry and non-road transport fuel.

Note: Other includes agriculture and buildings.

A number of challenges remain to achieving this scale-up in hydrogen production and use. They include creating demand for low-emissions hydrogen in industries that currently depend on hydrogen from fossil fuels, agreeing on international standards for emission intensities and safety considerations, developing an investment case for the early development of large-scale infrastructure (such as pipelines, ports, dedicated renewable electricity and underground storage), and price discovery and assessment.

Recent commercial decisions confirm expectations that oil and gas companies can play a central role in overcoming these challenges. Shell and Sinopec were the first companies to start construction of 200 MW electrolyser installations, in large part because their refineries provide a reliable offtake of low-emissions hydrogen without significant new infrastructure and their existing steam methane reformers can be used as back-up to manage variability of the new supply. As fuel suppliers, they are well-placed to diversify these projects into vehicle refuelling and low-emissions fuels manufacturing (such as ammonia or synthetic oil products) as those sources of hydrogen demand materialise. Coupled with their expertise in CCUS for low-emissions hydrogen production from fossil fuels, this combination gives oil and gas companies an almost unique ability to manage risks during the earliest phases of scale-up. First-mover advantages could then pay off handsomely if hydrogen and hydrogen-based fuels become commodities that are widely used and traded.

2.3.3 Bioenergy

Bioenergy – in solid, liquid and gaseous forms – is already a major source of energy today and is an essential component of net zero transitions. Liquid transport biofuels, biogas and biomethane[9] offer a major opportunity for the oil and gas industry to use existing oil and gas processing, transmission and distribution infrastructure while delivering a zero-emission source of energy.

Liquid biofuels

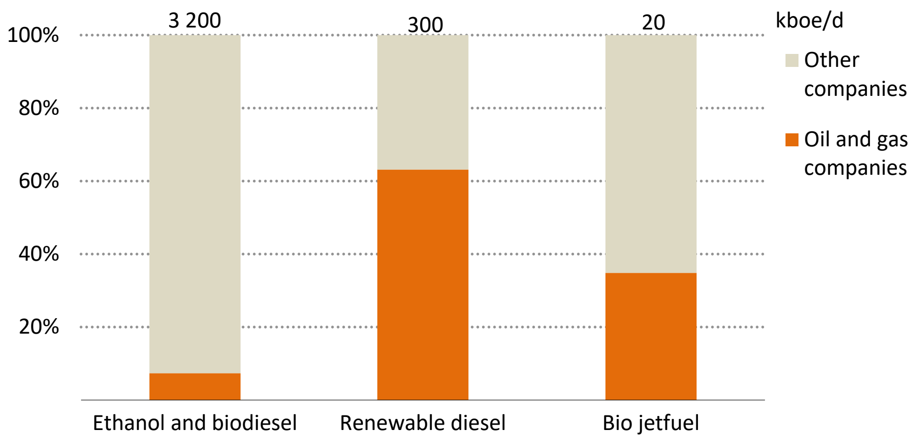
The oil and gas industry is already a player in the production of liquid biofuels. It owns or operates approximately one-third of biojet fuel capacity globally and two-thirds of renewable diesel production capacity (Figure 2.26). Liquid biofuels can often make use of units and facilities at traditional refineries. The co-processing of biofuels by blending small amounts of bio-based feedstock into existing conversion units is already a widely adopted practice that can be achieved without the need for infrastructure upgrades. Hydrotreating units, normally used to eliminate sulphur and other impurities in the final production stages of petroleum products, can also be converted to produce renewable diesel and biojet fuel.

Refineries can also be converted to produce 100% biofuels. This would require new upfront investment to modify and adapt existing assets, but it would allow refiners to leverage available assets such as utilities, storage and transport infrastructure, along with the associated human capital. The overall cost of conversion is generally much lower than that required to build such infrastructure from scratch. However, full conversion to bioenergy would require sourcing sustainable feedstocks at sufficient scale; these are not necessarily available in dense quantities close to today's existing infrastructure.

Other liquid biofuel feedstocks and production routes require new facilities and infrastructure, but could still make use of the existing skills and expertise of some parts of the oil and gas industry. For example, the gasification of solid biomass requires preprocessing, gasification, syngas purification and the synthesis itself, as well as hydroprocessing of intermediate liquids into final products. In the APS, total liquid biofuel production increases from 2 mboe/d today to 5 mboe/d in 2030 and 7 mboe/d in 2050 (Figure 2.27). Investment in biodiesel, renewable diesel and biojet fuel capacity rises from very low levels today to around USD 20 billion in 2030.

[9] Biogas is a mixture of methane, CO_2 and small quantities of other gases produced by anaerobic digestion of organic matter in an oxygen-free environment. Biomethane (also known as renewable natural gas) is a near-pure source of methane produced either by removing the CO_2 from biogas or through the gasification of solid biomass followed by methanation.

Figure 2.26 ▻ Oil and gas sector capacity for liquid biofuel production, 2022



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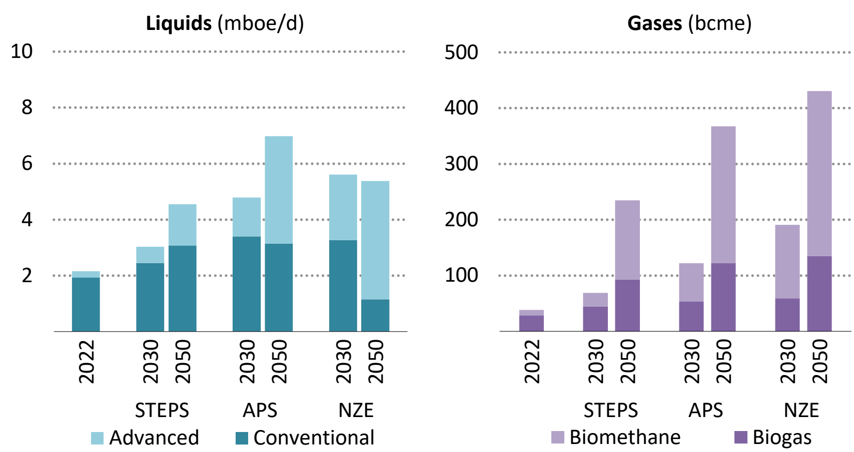
Oil and gas companies have a strong presence in emerging parts of the liquid biofuels value chain that can be processed in existing refineries following modification.

Note: kboe/d = thousand barrels of oil equivalent per day.

Figure 2.27 ▻ Modern liquid and gaseous bioenergy use by scenario



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Oil and gas companies are well-positioned to satisfy growing investment needs for high value-added bioenergy supply, such as biojet fuel, renewable diesel and biomethane.

In the NZE Scenario, the production of liquid biofuels rises to 6 mboe/d in 2030, requiring a sixfold increase in investment by 2030 from today's levels. Production then remains 6 mboe/d to 2050 and investment levels decline. The high penetration of electric cars and trucks leads to a reduction in biofuel consumption in road transport after 2030, and more of the limited supply of sustainable bioenergy available is used in the form of solid bioenergy in power generation and industrial applications.

Scaling up advanced biofuels will be critical to ensure minimal impacts on land use and food prices while expanding biofuel production.[10] In the APS, the share of advanced biofuels in total biofuel production rises from about 10% today to nearly 60% in 2050. In the NZE Scenario around 80% of liquid biofuels are produced from advanced feedstocks in 2050. However, given the limited availability of the advanced feedstocks in use today, new technologies and waste streams will need to be commercialised to satisfy growing demand.

The oil and gas industry, with its access to capital, value chain synergies and established presence in the sector, can play a key role in unlocking the necessary investment in liquid biofuels. If the industry were to maintain its current share of investment in the liquid biofuel market in the APS through to 2030, it would need to invest around USD 40 billion over the next seven years.

Biomethane

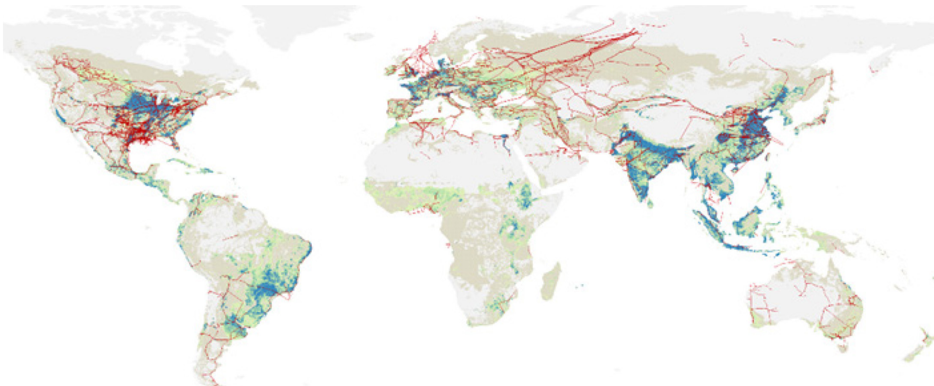
Biomethane is another part of the bioenergy value chain that has attracted attention from oil and gas companies, who are seeking to develop the fuel as an alternative to natural gas or as a transport fuel. This has proven a particularly attractive proposition in Europe following Russia's invasion of Ukraine; the European Commission in its Fit for 55 and RePowerEU plans has set a target for a biomethane production level of 35 bcm by 2030, from around 3 bcm currently. California's low-carbon fuel standards have also provided a spur for the development of biomethane as a transport fuel in the United States.

The biogas and biomethane industry is currently dominated by relatively small players, such as independent producers, farming co-operatives, waste management firms and municipalities. A handful of larger players have recently been acquired by oil and gas companies to gain a foothold in the emerging industry. BP bought US-based Archaea Energy in late 2022 for USD 4 billion, Shell acquired Denmark-based Nature Energy for USD 2 billion, and TotalEnergies has made a series of smaller acquisitions, such as the purchase of Fonroche Biogaz in France and Poland-based biogas producer PGB.

The global potential for biogas and biomethane remains largely untapped. A detailed geospatial analysis of the sustainable agricultural wastes and residue feedstocks reveals a potential of just under 1 000 bcme (Figure 2.28). Around 30% of this potential lies within 20 kilometres of major gas pipeline infrastructure, providing a good match with possible large-scale production and injection into gas grids. Around 40% of the potential is otherwise near a road network, an indicator for the potential for feedstocks to be collected and brought to centralised biodigesters, to produce biogas for local heat and power requirements or otherwise upgraded to biomethane for use in transport.

[10] Advanced biofuels are produced from non-food crop feedstocks, which can deliver significant life cycle GHG emission savings compared with fossil fuel alternatives and do not directly compete with food and feed crops for agricultural land or cause adverse sustainability impacts.

Figure 2.28 ▷ **Assessed annual biomethane potential from agricultural wastes and residues, and location of natural gas transmission pipelines**



Around 300 bcm of biomethane could be produced from agricultural wastes and injected into nearby gas grids. Oil and gas companies have recently invested in this area.

Sources: IEA analysis based on FAO (2023) and Global Energy Monitor (2022).

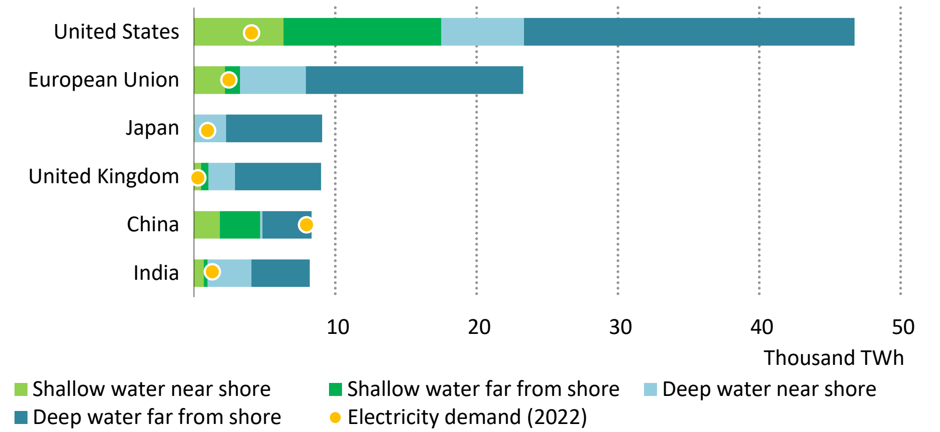
Oil and gas companies could improve the biomethane value chain by helping it to achieve scale, through standardising contracts, equipment and logistical operations, and integrating biomethane into existing gas markets and infrastructure. Some companies participate in the value chain mainly as offtakers or traders of certified sustainable biomethane, enabling both demand and supply aggregation to support larger economies of scale. This is crucial in net zero transitions, where biomethane rapidly grows in the years ahead, from 10 bcme in 2022 to 70 bcme in the APS in 2030 and 130 bcme in the NZE Scenario.

2.3.4 Offshore wind

Offshore wind provides around 1% of global electricity generation, but has huge untapped potential. The world's offshore wind potential is 17 times the scale of global electricity demand in 2022 (Figure 2.29). In most markets, offshore wind alone could generate enough electricity to meet total electricity demand in aggregate (IEA, 2019).

The involvement of the oil and gas industry in the offshore wind market is still in its relative infancy; around 2% of offshore wind capacity in operation today was developed by oil and gas companies. However, plans are expanding. In 2022, TotalEnergies announced a project pipeline of 6 GW of offshore wind, which would take its total to 11 GW; Shell also has around 9 GW in the pipeline and Equinor has ambitions to install 12-16 GW by 2030 (IEA, 2023i). If realised, these capacity additions would rival those of pure-play developers such as Ørsted over the same period. In 2023, in the world's largest offshore wind auction, BP and TotalEnergies bid USD 13 billion for the right to build wind farms in the North and Baltic seas.

Figure 2.29 ⊳ Offshore wind potential and 2022 electricity demand in selected regions and countries



Offshore wind has untapped potential that is almost 17 times global electricity demand in 2022 and exceeds current electricity demand in most countries.

Notes: Shallow water = 10-60 m. Deep water = 60-2 000 m. Near shore = < 60 km. Far from shore = 60-300 km.

The offshore wind industry is currently facing challenges in several markets as project costs rise due to supply chain disruptions, elevated financing rates and extended permitting times. These pressures are particularly acute in the United States, where companies including Shell, BP and Ørsted have halted several large offshore wind projects in recent months, calling on policy makers to address these challenges and help the industry to regain confidence.

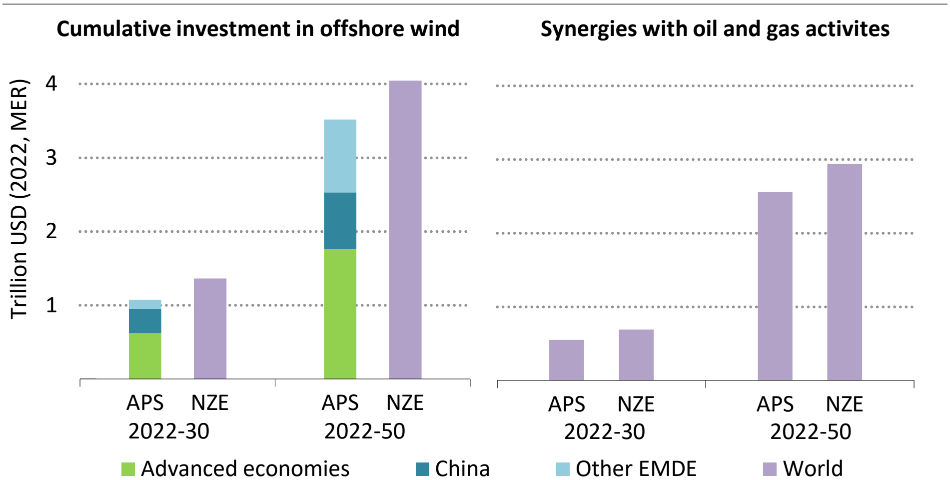
A number of possible synergies exist between the skills and resources of the oil and gas industry and those needed for offshore wind developments. They include the ability to manage large-scale projects in challenging offshore environments, the efficient utilisation of vessels during installation and operation, and the maintenance of offshore infrastructure. Offshore wind farms are capital-intensive: projects in 2022 cost around USD 3 million per MW installed capacity and have an average total cost of around USD 1 billion. There are also some major differences between offshore wind developments and the skills of the industry. For example, offshore wind farms require deploying a large number of smaller structures quickly and connecting these with a large amount of equipment and cables, while offshore oil and gas operations tend to involve planning and constructing a much smaller number of more centralised and complex structures.

As offshore wind farms are likely to involve increasingly more complex structures in deeper water that are further from shore, offshore oil and gas platforms could be repurposed or reutilised as operation and maintenance facilities. The use of drones and remotely operated vehicles – already common practice in many offshore oil and gas facilities – for wind blade and subsea inspections and repair would also reduce the necessity for workers stationed at offshore platforms. The manufacture of substations, which are required for all new offshore wind farms larger than 100 MW, and the cables connecting one turbine to another could also draw on the expertise of the oil and gas supply chain.

Floating offshore wind power technologies are needed to tap additional potential in deep water and the offshore oil and gas industry is emerging as a key player in this sector. The experience of the oil and gas sector is especially beneficial to the design and construction of floating facilities and their associated anchors and moorings. The first floating wind farm in the world is operated by Equinor and Masdar, and three of the seven new floating wind farms recently opened in Europe are owned or partially owned by oil and gas companies. Most floating wind projects are still relatively small, but the involvement of oil and gas companies could allow for larger projects, helping the sector as a whole to expand faster and to further reduce costs. The levelised cost of offshore wind electricity indicates that the technology is on track to be competitive with most fossil fuels before 2030, trailing only solar PV and onshore wind.

In the APS, almost 1 800 GW of offshore wind capacity is installed globally by 2050, providing 10% of electricity generation globally. This requires almost USD 4 trillion of cumulative investment to 2050 (Figure 2.30). Around half of this has significant potential synergies with the offshore oil and gas industry, including the construction and installation of foundations, and associated logistics. There are also synergies in operation and maintenance costs and this implies a USD 2.6 trillion opportunity for the oil and gas industry over the next 30 years.

Figure 2.30 ▷ Cumulative investment in offshore wind and spending with synergies with oil and gas activities in the APS and NZE Scenario



Cumulative investment in offshore wind to 2050 is close to USD 4 trillion in both the APS and NZE Scenario, and has a large crossover with oil and gas activities.

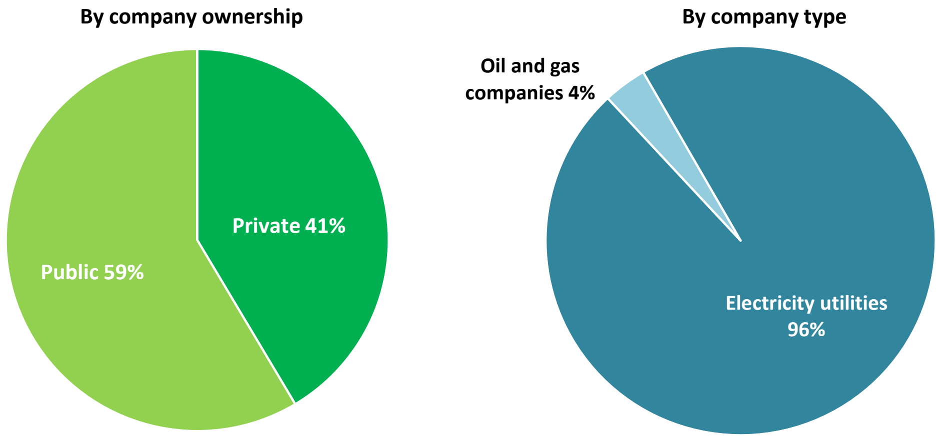
Notes: EMDE = emerging market and development economies.

In the NZE Scenario, nearly 2 200 GW of offshore wind capacity is installed by 2050. Emerging market and developing economies account for around 60% of global offshore wind electricity generation in 2050, with major growth in China, India and Viet Nam. Cumulative investment to 2050 exceeds USD 4 trillion and there is around USD 3 trillion of capital and operating spending to 2050 that would have significant synergies with the oil and gas industry.

2.3.5 Geothermal

Geothermal currently provides just under 1% of global energy supply. It is used for electricity generation and to provide heat to residential and commercial buildings. Oil and gas companies have long recognised the potential of geothermal energy as an opportunity to diversify their activities while leveraging their drilling expertise. However, pure-player geothermal developers and state-owned enterprises own the vast majority of capacity, with oil and gas companies owning less than 5% of capacity worldwide (Figure 2.31).

Figure 2.31 ⊳ Global geothermal capacity by company type, 2022



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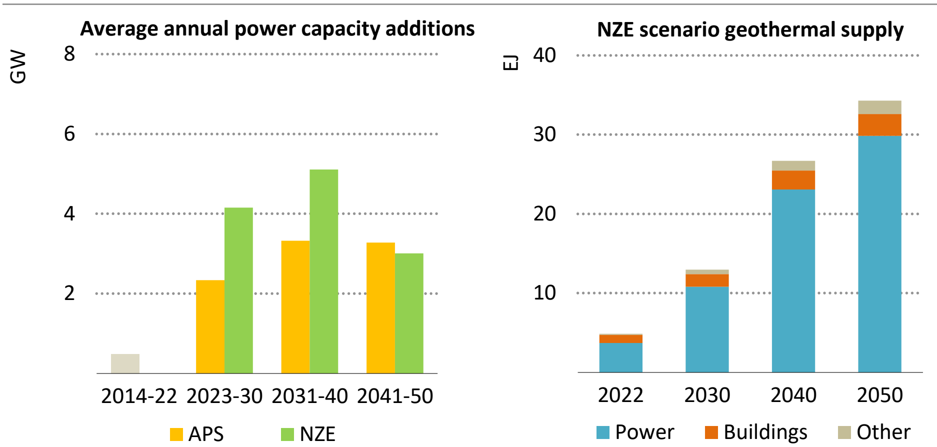
Oil and gas companies own less than 5% of installed geothermal capacity globally.

Geothermal and upstream oil and gas developments share many similarities. Most existing geothermal developments have tapped into shallow heat resources that are relatively easy to access, but there is significant potential for using high-temperature geothermal energy from deeper sources in many parts of the world (sometimes known as "enhanced geothermal systems"). Techniques developed by the oil and gas industry, including a deep understanding of the subsurface, drilling and completing wells, predicting fluid flows and managing large-scale projects, can help to tap into these deep geothermal resources. The potential for technology spillovers is considerable given the wide range of transferrable disciplines, including resource characterisation, exploration, drilling, operations, maintenance, and risk management. It is highly likely that the costs of geothermal could be lowered and performance improved if it could make use of the technologies and knowledge of the oil and gas sector (Schulz & Livescu, 2023).

In the APS, geothermal demand doubles to 2030 and increases by a factor of five to 2050. By 2050, there is 100 GW of geothermal power capacity globally, up from 15 GW today, and this requires around USD 250 billion of investment through to 2050. The best prospects for growth are in the United States, Southeast Asia and Africa, given their untapped potential and growing electricity demand. Electricity generation costs from geothermal are in general higher than onshore wind and solar PV, but it can play an important role in balancing wind and solar PV generation. In the NZE Scenario, geothermal power capacity grows to 130 GW by 2050, requiring around USD 280 billion of cumulative investment through to 2050; total geothermal supply in 2050 is around seven times higher than in 2022 (Figure 2.32).

There are differences between oil and gas and geothermal operations that may mean the industry plays only a marginal role in its future growth. They include differences between the volumes of fluids produced and temperature variations in geothermal and hydrocarbon reservoirs, and contrasts in the supply chains for electricity (including engagement with different customers). The returns on investment are also likely to be very different. While oil and gas industry support could help drive geothermal project cost reductions and boost economies of scale, a much more proactive approach, matched with increased investment levels, would be required.

Figure 2.32 ▷ Geothermal deployment in the APS and NZE Scenario



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Geothermal energy supply increases by a factor of seven to 2050 in the NZE Scenario, mainly from increases in the power sector.

2.3.6 Plastics recycling

The demand for plastics has grown rapidly in recent years and around 12 mb/d of oil was used to produce plastics in 2022. Plastics are very useful, but significant levels of emissions are associated with their production – direct emissions of around 250 Mt CO_2 were emitted in 2022 just to produce high-value chemicals, the main precursor to plastics – and they result in large amounts of waste. Momentum is growing behind policies and initiatives that aim to reduce plastic use and increase recycling rates. More than 60 countries have restricted or banned the production and use of single-use plastics, and the European Union announced a plastic packaging recycling rate target of 50% in 2025 and 55% in 2030. At present plastics recycling is mainly performed using mechanical methods. These are generally low cost and low emissions, but they cannot be used to process the mixed, complex and contaminated plastic waste that makes up around 20-50% of collected material today (Vanderreydt et al., 2021). Mechanical recycling also leads to degradation of quality that often prevents the use of secondary plastic in high-grade applications like food packaging.

Table 2.2 ⊳ Oil and gas companies' involvement in selected commercial-scale chemical recycling projects

Oil and gas company	Recycling technology developer	Location	Capacity (kt waste/yr)	Start-up	Agreement
Pyrolysis					
TotalEnergies	Honeywell, Sacyr	Andalusia (ES)	30	2023	Offtake agreement
	Plastic Energy	Grandpuits (FR)	15	2024	Joint venture
	JV Plastic Energy and Freepoint Eco-systems	Texas (US)	33	2024	Offtake agreement
	Plastic Energy	Seville (ES)	33	2025	Offtake agreement
ExxonMobil	ExxonMobil	Texas (US)	35	2022	Investment
	Plastic Energy	Gravenchon (FR)	25	2024	
BP	Clean Planet Energy	Teesside (UK)	20	tbd	Offtake agreement
Shell	Nexus	Georgia (US)	15*	tbd	Offtake agreement
	Pryme	Rotterdam (NL) tbd (NL)	60 350	tbd 2024	Strategic partnership and offtake agreement
	Freepoint Eco-Systems	Ohio (US) Gulf Coast (US)	90 192	2024 tbd	Exclusive offtake agreement
SK	Plastic Energy	Ulsan (KR)	66	2025	Strategic partnership
Sabic**	Plastic Energy	Geleen (NL)	20	tbd	Joint venture
Gasification					
Repsol	Enerkem	Tarragona (ES)	400	2025	Joint venture
Solvolysis					
SK	Loop Industries	Ulsan (KR)	70*	2025	Joint venture

* Recycled product; ** 70% owned by Saudi Aramco.

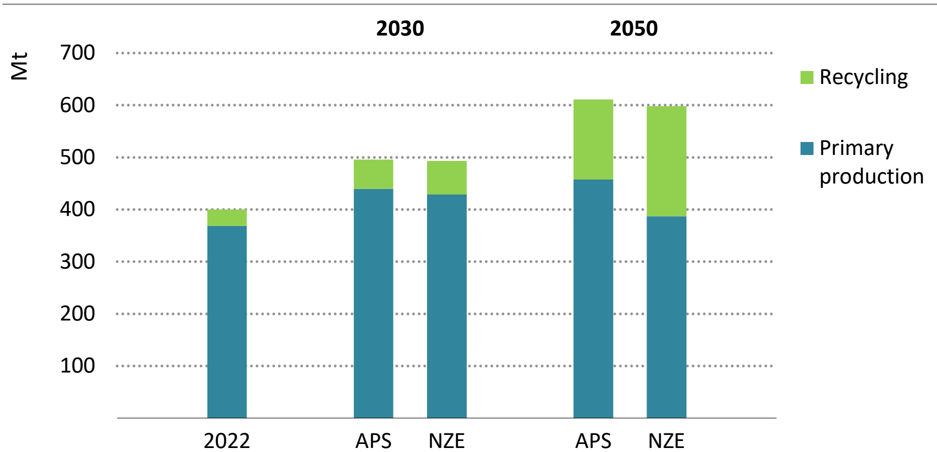
Notes: kt = thousand tonnes; tbd = to be decided. ES = Spain; FR = France; KR = Korea; NL = Netherlands; UK = United Kingdom; US = United States.

Alternative methods, such as chemical recycling, could help address some of these issues. For example, solvolysis uses solvents to decompose waste into compounds that can be re-used to make recycled plastic that has a quality similar to virgin plastics; pyrolysis and gasification use high-temperature processes to break down difficult-to-recycle plastics into fuels and feedstocks for industrial processes, including making plastics. These present a potential new business opportunity for the oil and gas sector, especially companies with petrochemicals production facilities that could be integrated with new pyrolysis or gasification units. Existing facilities can be used for downstream treating of the products and the workforce is familiar with similar types of processes and such large-scale, capital-intensive projects.

A number of chemical recycling plants are starting operation and there is a strong pipeline of future projects, many of which involve oil and gas companies (Table 2.2). Companies have also announced specific targets for recycled content in their plastic production. For example, TotalEnergies has a target to increase recycled and renewable content in their plastics to 30% by 2030, Shell is aiming to have 30% recycled-content packaging material by 2030, and ExxonMobil has an ambition to have 0.5 Mt of advanced recycling capacity by year-end 2026.

In the APS, the share of recycled plastic production in the global total increases from 8% today to 25% in 2050. This helps to curb some of the increase in the use of oil for primary plastics production, but oil use for this application still rises to 2050 (Figure 2.33).

Figure 2.33 ▷ Primary plastic production and recycling in the APS and NZE Scenario, 2022-2050



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The share of recycling in total plastics production increases alongside wider efforts to reduce waste and oil imports, avoiding 5 mb/d of oil use in 2050 in the NZE Scenario.

In the NZE Scenario, trends are similar to the APS to 2030, but the plastics collection rate rises faster thereafter and oil use declines faster after its peak; by 2050 oil use for plastic production is only marginally above that in 2022. In 2050, recycled plastics accounts for around 35% of total plastics production. Along with the introduction of bio-based and alternative feedstocks, and the trend towards more durable materials, this avoids around 5 mb/d of oil use for primary plastic production in 2050 compared to a baseline where recycling remains at current levels. In the NZE Scenario, plastic waste is not converted into transport fuels, as the carbon in the plastic is still of fossil origin.

There are large differences in the emissions associated with different plastics production and recycling routes. Currently, producing a tonne of primary plastic results in around 2-6 t CO_2-eq emissions, depending on the type of plastic and the region, including the direct and indirect emissions from production and conversion (OECD, 2022; Vanderreydt et al., 2021). Mechanical recycling tends to be 75-90% less emissions-intensive than primary production, with the emissions intensity of the electricity used a key factor. Reductions in emissions from oil extraction and processing, and during the plastics manufacturing processes, mean that by 2050 one tonne of primary plastic produced in the NZE Scenario results in less than 0.1 t CO_2-eq throughout the value chain.

Increasing mechanical recycling rates helps reduce CO_2 emissions from plastics use in the NZE Scenario, especially over the next 10-20 years. In the longer term, however, the impetus for further increases in the plastics recycling rate stems more from policies and regulations aiming to cut down on waste generation and oil imports rather than to reduce CO_2 emissions.

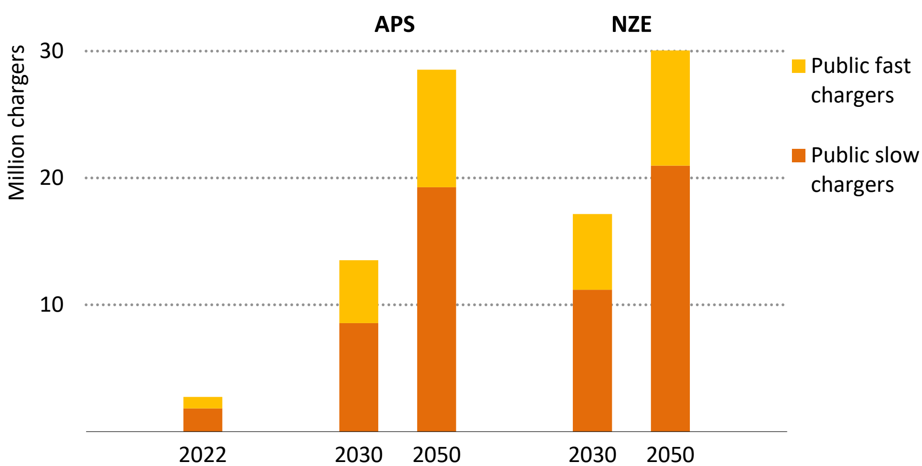
Treating mixed and difficult-to-recycle plastics will be necessary to reach high recycling rates, and chemical recycling is set to play a role in both the APS and NZE Scenario. However, extensive efforts are needed to reduce GHG emissions and local air pollutant emissions from these processes. At present, lifecycle emissions per tonne of plastic produced from solvolysis are around 1.6 t CO_2-eq (Vollmer et al., 2020), varying according to the type of plastic, and from pyrolysis are around 3 t CO_2-eq (Möck et al., 2022). The knowledge and expertise of the oil and gas industry could be critical in helping to reduce these emissions. One option is to convert the gaseous by-products into chemicals that can be used to make durable products, rather than using them as fuel for the process. For pyrolysis, this could be achieved by transforming by-product methane into methanol and electrifying the process heat demand. For gasification, low-emissions hydrogen could be used to convert the by-products from plastic waste into chemicals such as methanol. Chemical recycling processes could also be equipped with CCUS to reduce emissions, although there are currently no announced projects to do this. These innovations would need to target an emissions intensity of production comparable with that of primary production in the NZE Scenario in 2050.

2.3.7 Electric vehicle charging

Sales of electric vehicles (EVs) have been growing exponentially in recent years and 29 million EVs – including 27 million electric cars – were on the road in 2022.[11] Sales are expected to continue to grow rapidly, but this will depend on affordable and accessible public charging together with options for home and workplace charging.

More than 2.7 million EV chargers are publicly accessible globally; two-thirds of these are in China and 20% in Europe. A number of governments have set out support for public charging infrastructure, notably in the proposed Alternative Fuels Infrastructure Regulation in the European Union, the National Electric Vehicle Infrastructure Formula Program in the United States, targets from the China National Development Reform Commission, and India's financing scheme under the Faster Adoption and Manufacturing of Electric Vehicles (FAME) scheme II (IEA, 2023k).

Figure 2.34 ▷ Projections for electric light-duty vehicle chargers in the APS and NZE Scenario, 2022-2050



EV chargers increase five to sixfold to support the growth of electric light-duty vehicles by the end of this decade, with around 30 million chargers required globally by 2050.

A number of oil and gas companies have taken an active role in the deployment of EV chargers, through investment in charging stations at their retail stations as well as acquiring charger manufacturers, network operators and service providers. Oil and gas companies currently operate around 350 000 charging points and this number is expected to double by 2025 under announced corporate strategies. Oil and gas companies, together with utilities,

[11] Figures do not include electric two/three-wheelers, of which there were more than 50 million on the road in 2022.

have their strongest presence in EV charging in Europe; pure-players and equipment manufacturers dominate the market in the United States and China. We estimate that over 13 million publicly accessible EV chargers are required to serve electricity demand for electric cars and vans on the road in the APS in 2030, and up to 17 million in the NZE Scenario (Figure 2.34). This requires around USD 100-120 billion of investment to 2030.

EV charging presents a business opportunity for oil and gas companies, especially those with existing retail networks. Historically, these have been the least profitable part of the oil and gas supply chain, but installing EV chargers could help diversify revenue streams and support sustainability efforts while keeping the physical stations and convenience stores in place and providing a boost to companies' brands. By retrofitting existing filling stations with fast charging equipment (usually 50-350 kilowatts), oil and gas companies can attract EV owners and commercial fleet operators with en-route charging demand and create significant revenue streams. These companies can also tap into synergies with renewable generation and storage options, as an increasing number of EV stations are coupling charging infrastructure with rooftop solar PV and battery storage options to optimise the balancing of the load.

Electric trucks in long-distance operations will increasingly rely on highway charging and seek bulk purchase contracts with EV charging operators. Public filling stations on highways can offer a charging hub if equipped with fast and ultra-fast charging, allowing electric trucks to perform operations that are currently carried out by diesel trucks with little to no additional dwell time in comparison. However, commercialisation of chargers with high charging power (around 1 MW) will incur significant costs in both installation and grid upgrades and require co-ordination with utilities to locate and plan appropriate transmission and distribution lines.

EV charging is attractive to oil and gas companies who are seeking to position themselves as a broader energy service provider with low-carbon energy assets, while offering them an effective means to diversify their businesses geographically in regions where EV uptake is already strong. The transition to an energy service provider is challenging, however, as the business models used to provide consumers with electricity as compared with fuels can differ markedly.

Strategic responses of companies

SUMMARY

- An increasing number of oil and gas companies are facing financial, social and political pressure to clarify the roles they intend to play in net zero transitions. The industry landscape is diverse and no single option will make sense for all, but many oil and gas companies have already made announcements on how they plan to respond.
- The oil and gas industry currently employs nearly 12 million workers globally. This falls by 10% in the APS and 20% in the NZE Scenario to 2030. Governments and companies will need to work together closely to maximise opportunities for reskilling workers.
- The ratio of investment in fossil fuels to clean energy rises from 1:1.8 globally in 2023 to 1:5 in 2030 in the APS and to more than 1:10 in 2030 in the NZE Scenario. These ratios can provide a guide for financial actors looking to assess the alignment of their portfolios with the outcomes of net zero transitions.
- A key strategic challenge for oil and gas companies is aligning existing skills and capital with the new requirements of energy transitions. We have developed a new framework to examine the possible contribution of oil and gas companies to net zero energy transitions that allows for a more granular discussion of the targets these companies are setting. The framework covers the following:
- **Scope 1 and 2 emissions:** in the NZE Scenario there is a 60% reduction in scope 1 and 2 emissions from oil and gas operations to 2030. A number of companies have already undertaken efforts to cut these emissions and this reduction is broadly consistent with all companies achieving the emissions intensity of current best practices by 2030.
- **New oil and gas projects:** the NZE Scenario does not require new exploration or the development of new long lead time upstream conventional oil and gas projects. No companies have to date made specific pledges on this.
- **Investment in clean energy:** Clean energy investment by the oil and gas industry represented 2.5% of its total capital spending in 2022. In the NZE Scenario, projected oil and gas revenues would allow the industry to invest around 50% of its capital budget in 2030 in clean energy. Achieving this level of investment would require governments, companies, shareholders and financial actors to work closely together.
- It is not axiomatic that oil and gas companies should invest in clean energy. If they do not, they would need to achieve very low emissions intensities and stop investment in new long lead time upstream projects if they are to claim that they are making a meaningful contribution to achieving net zero emissions by 2050.
- The NZE Scenario trends on scope 1 and 2 emissions and oil and gas industry investment in clean energy provide important guidance for oil and gas companies looking to play their part in net zero transitions, even if the energy transition does not accelerate at the pace seen in that scenario.

3.1 Introduction

Oil and gas companies have a wide range of possible responses to the challenges posed by net zero transitions. It will be for companies and their state and private owners to decide on the best way forward based on their own assessment of their capabilities and the opportunities and risks that exist, and the energy and climate policies in place in the locations where they operate. Some companies may decide, for example, that their core competencies are in oil and gas and that they will focus on supplying them as cleanly and cheaply as possible even while they phase down production to be consistent with net zero transitions. Other companies may choose to reposition themselves as "energy companies" and look to develop the fuels and technologies needed in the new energy economy.

The debate around the role of the oil and gas industry in net zero transitions has often been framed in binary terms. A company is either fully aligned or fully out of alignment. This chapter looks to move beyond this dichotomy by exploring the different options available to oil and gas companies and degrees to which these are aligned with net zero transitions. This includes a new framework to help key stakeholders, both inside and outside the industry, engage in a more informed, granular and transparent discussion on the statements, targets, and actions of oil and gas companies.

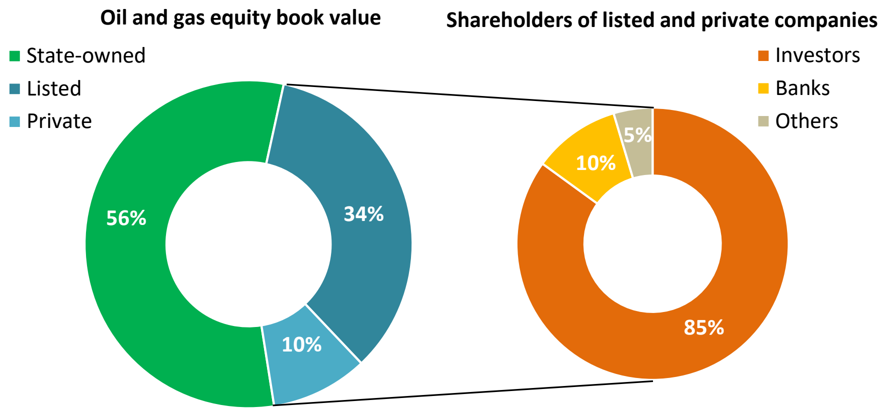
This chapter is structured as follows. Section 3.2 sets out the pressures facing oil and gas companies from the challenges posed by climate change and how they could evolve in the future. It examines the demands of investors and financial markets, social and political pressures, and the future prospects for oil and gas workers. Section 3.3 examines oil and gas companies' responses to date to the challenge of reaching net zero. It analyses the targets announced by companies both to cut down on emissions from oil and gas operations and to diversify their activities away from oil and gas. Section 3.4 explores what current oil and gas companies could look like in 2050 if they align their portfolios with trends in the NZE Scenario. Section 3.5 addresses what changes by oil and gas companies would be consistent with net zero transitions. Finally, Section 3.6 describes the IEA's new framework, which can be used to understand the alignment of oil and gas company targets with the outcomes of the NZE Scenario.

3.2 The rising pressures on oil and gas companies

3.2.1 Financial pressures

As efforts to tackle climate change have moved up the agenda, a growing number of financial actors have been reviewing their engagement with oil and gas companies. The most direct impact has been on publicly traded oil and gas companies as equity and debt have come under increased scrutiny due to shareholder activism and stricter lending policies by European and US banks (Figure 3.1). This group of companies makes up around one-third of the total equity value of the oil and gas industry. Privately owned and government-owned companies can also be affected due to stricter lending conditions, and banks are increasingly including conditions on lending to oil and gas companies based on environmental policies.

Figure 3.1 ▷ Oil and gas company equity value by company type, and shareholders of listed and private oil and gas companies



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Just over half of the oil and gas equity market cannot be directly accessed by institutional investors given the major role played by state-owned companies.

Note: Equity book value = difference between total assets and total liabilities.

Source: IEA analysis based on 2 000 oil and gas companies representing more than 70% of production using data from S&P Global (2023).

Rising concerns over climate change have developed into a wider movement among banks and investors to understand the alignment of their portfolios with environmental, social and governance (ESG) principles. ESG is a broad concept encompassing a wide range of actors and activities, but a core tenet of the "environmental" pillar is to evaluate the activities and investment plans of individual companies against sustainability goals. ESG investing has grown rapidly in recent years, reaching USD 2.5 trillion of assets under management in 2022 (IEA, 2023a). This has elicited a response from the oil and gas industry and financial actors with oil and gas holdings, stemming from concerns over reputational damage, impacts on share performance, increased borrowing costs and a reduction in financing options.

At present many ESG reporting frameworks suffer from a lack of transparency, consistency and standardisation. Governments and regulatory bodies are responding by introducing regulations and reporting requirements to enhance transparency and disclosure of ESG-related information. Examples include the EU taxonomy for sustainable activities, and the Green Bond Principles and Common Ground Taxonomy released in China. A growing number of central banks are also conducting climate stress tests; banks in at least 18 jurisdictions are, or soon will be, subject to requirements to implement such testing.

The two main avenues open to investors, banks and development finance institutions looking to influence oil and gas companies are divestment and active engagement.

- **Divestment** is a decision to sell ownership of equity or bonds in oil and gas companies. A number of prominent campaigns in recent years have generated public pressure on oil and gas companies and raised awareness of their contribution to climate change. The value of assets under management committed to some form of fossil fuel divestment increased from just over USD 50 billion across 180 institutions in 2014 to nearly USD 40 trillion across 1 500 institutions in 2021 (Lipman, 2021). A key risk with divestment is that it transfers ownership to institutions that are less focused on ESG or that do not have as stringent climate goals; this can limit, or even negate, the intended purpose of divestment.
- **Active engagement** involves retaining ownership or influence in oil and gas companies and pushing them to achieve sustainability-related goals. Nearly 500 shareholder resolutions related to environmental and climate issues were filed in the United States in 2021 and 600 were filed in 2022 (ISS, 2023). A number of investor coalitions have also emerged in recent years that aim to collectively engage with companies and push for these goals, including the Net Zero Asset Owner Alliance, Climate Action 100+, and the Principles for Responsible Investing. The key risks with active engagement are that the target companies do not undertake real efforts to reform or that they diversify into areas where they have fewer commercial advantages.

National oil companies (NOCs) currently rely on debt for around 35% of their total investment and they have also responded to these financial pressures. Most NOCs generate enough income from their upstream assets to cover capital requirements, but their strategic and financial autonomy is dictated by their host governments, and debt financing is often used when they need to finance a rapid increase in production, expand overseas or grow new business areas.

Development finance institutions (DFIs) have in the past helped finance oil and gas projects in a number of emerging market and developing economies, although their share of total oil and gas investment was less than 0.2% in 2022. Many DFIs have restricted financing for fossil fuels. For example, the World Bank Group stopped investing in upstream oil and gas in 2019, and the European Investment Bank has indicated that it will no longer consider new financing for unabated fossil fuel projects from 2021. Other DFIs have restricted financing for coal and oil, but make allowances for natural gas (Ferragamo & Auth, 2021).

3.2.2 Social, legal and political pressure

The oil and gas industry requires a social licence to be able to build and operate facilities in the areas that it is active. In the past, concerns about projects traditionally focused on local impacts, including the potential for air pollution and water use and contamination. But the threats posed by climate change – and the industry's contribution to climate change – have widened and heightened the pressures the industry faces. These have been manifested in a number of ways, including through local protests and direct action, legal action and political pressure.

Local protests and direct action. The oil and gas industry is facing increased opposition to new oil and gas infrastructure projects in some parts of the world. These can delay or lead to the cancellation of licensing and development of some projects. The East African Crude Oil Pipeline (EACOP) project, for example, has faced opposition due to concerns about climate and biodiversity impacts, and protests and blockades have delayed its development. In some countries, citizens have also been taking direct action through protests and campaigns to raise awareness of climate issues and to oppose new oil and gas licensing rounds and project developments.

Legal action. Civil society organisations, often supported by institutional investors, have brought legal action against oil and gas companies over their climate strategies. More than 2 300 climate-related legal cases have been raised around the world to date and around 30% of cases brought in 2022 targeted fossil fuel exploration, production and transport (Setzer & Higham, 2023). Many of these cases focus on the majors and their trade associations to discourage them from continuing high-emissions activities, to force them to integrate climate considerations into strategic decisions, or to seek financial compensation from climate change-related damages (Wentz, et al., 2023).

Oil and gas companies have also filed lawsuits against climate policies. These have included challenges against pauses on new oil and gas leasing on public lands and in offshore waters in the United States, fuel economy standards, greenhouse gas (GHG) reporting requirements, and against the revocation of permits for large-scale infrastructure projects (Sabin Center for Climate Change Law, 2023).

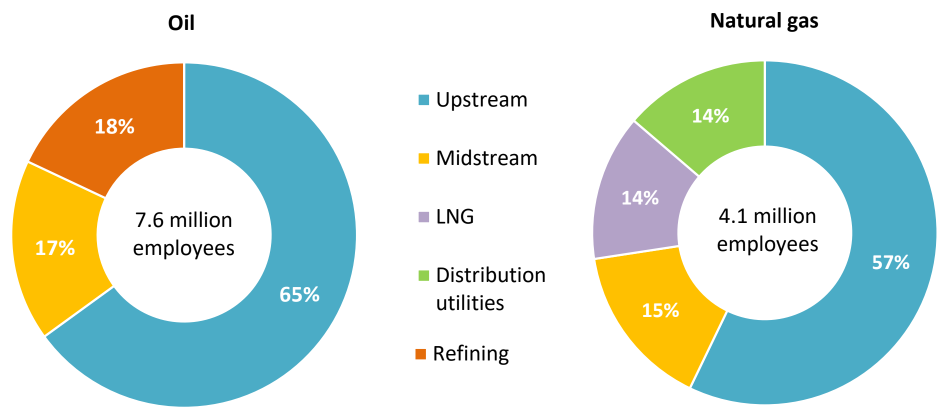
Political pressure. Few governments to date have explicitly stated a wish to stop all oil and gas activities in their jurisdictions: those that have include Denmark, Costa Rica, Ecuador, Spain and France (Higham & Koehl, 2021). However, government policies, regulations and guidance related to climate change are affecting the operations and business decisions of oil and gas companies, including national oil companies (NOCs). For example, India's Oil and Natural Gas Corporation (ONGC) is required to diversify its investment portfolio to include renewable energy alongside its plans for oil and gas expansion. As part of its most recent nationally determined contribution (NDC), the United Arab Emirates indicates that the Abu Dhabi National Oil Company (ADNOC) will become a net zero emissions company by 2050. Iraq aims to leverage international support to reduce its greenhouse gas emissions by 15% by 2030, including by reducing methane emissions from its oil and gas activities. Qatar's NDC lists measures to diversify the economy away from hydrocarbons and commits its NOC to zero routine flaring by 2030 and to reduce methane emissions across the natural gas value chain.

A number of intergovernmental and civil society organisations exist that seek to stop future oil and gas licensing or developments. Examples include the Beyond Oil and Gas Alliance, which is an international alliance of governments and other stakeholders looking to facilitate the managed phase-out of oil and gas production, and the Fossil Fuel Non-Proliferation Treaty Initiative, which is a network of civil society organisations looking to stop the expansion of fossil fuel use and wind down existing production.

3.2.3 Employment

The oil and gas industry employs nearly 12 million workers globally (Figure 3.2). Around 60% are employed in upstream segments, developing projects and maintaining production at existing fields, while the remainder work in transport, refining and utilities. Workers are clearly essential to oil and gas activity, but fears over long-term job prospects means some parts of the industry have recently been struggling to retain and hire workers.

Figure 3.2 ▹ Employment in oil and gas supply, 2022



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The largest share of workers are engaged in upstream activities, while in gas supply around 15% of employment is linked to each of distribution utilities, LNG and midstream work.

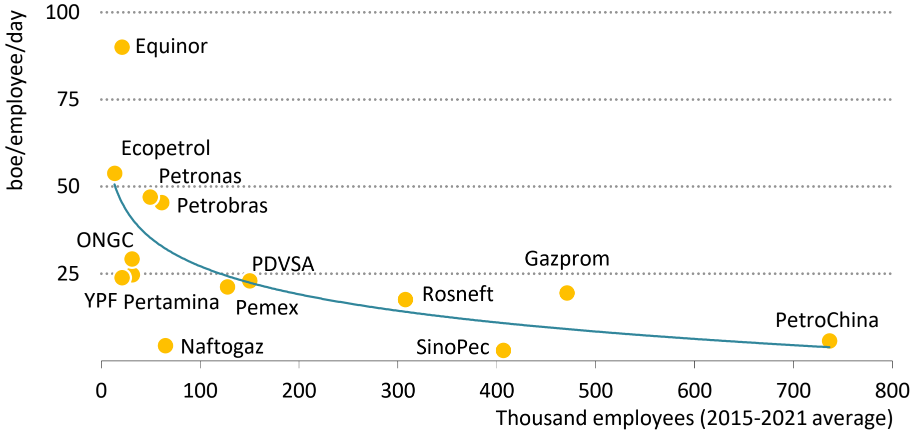
Notes: LNG = liquefied natural gas. Does not include employment at retail refuelling stations, as many of these jobs are connected to service and retail and are not linked exclusively to oil and gas.

The plunge in oil demand and prices in 2020 spurred massive layoffs in the oil and gas industry, with around a million jobs lost worldwide that year. Employment in oil has recovered more slowly than gas from these pandemic-induced job losses, partly because of the strong growth in LNG trade in 2022 following Russia's invasion of Ukraine. Around 60 liquefaction and regasification terminals are currently under construction or coming online worldwide, translating into nearly 150 000 LNG-related jobs in construction alone.

NOCs and international national oil companies (INOCs) represent a much greater share of oil and gas employment than the majors, and they were less likely to lay off workers due to the Covid-19 pandemic (Figure 3.3). State-owned oil and gas companies may be seen by host governments as a means to provide secure employment for their citizens, and NOCs tend to have greater employee headcounts and lower productivity than INOCs, which rely more heavily on outsourcing to contractors and oilfield services companies.

NOCs generally have more employees than the majors and are often in less diversified economies, but they may also have a greater capacity to weather declining demand by reassigning employees elsewhere in the public sector. In any case, oil and gas employment does not disappear, even in the APS and NZE Scenario. In 2030 there are around 10.5 million oil and gas workers in the APS and over 9 million workers in the NZE Scenario. Jobs in the gas supply sector tend to be more robust, with the number of workers declining more slowly over this period in both the APS and NZE Scenario (Figure 3.4).

Figure 3.3 ▹ Oil and gas production to employee ratio versus size of workforce in selected NOCs and INOCs, 2015-2021 average



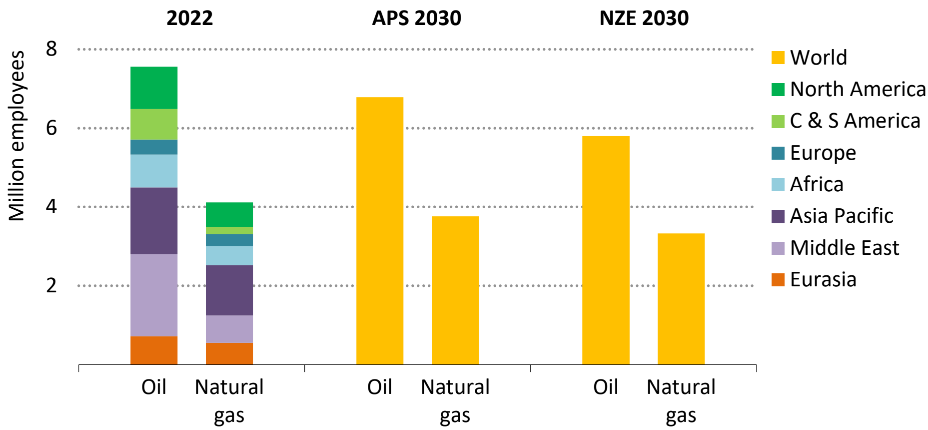
Nationally owned oil and gas companies generally have an inverse relationship between workforce size and labour productivity.

Notes: boe= barrel of oil equivalent. Figure excludes Saudi Aramco, which produces more than 180 boe/employee per day.

Net zero transitions result in large shifts in employment between and within different parts of the energy sector. But the number of job losses in oil and gas employment is smaller than the number of clean energy jobs created in both the APS and NZE Scenario. Moreover, many oil and gas workers possess skills that are in high demand in other parts of the energy sector; for example, petroleum and gas engineering skills are highly applicable to the geothermal industry and chemical engineers in refineries can help with the scale-up of hydrogen and hydrogen-based fuels (see Chapter 2).

The mobility and skills of oil and gas workers, especially highly skilled employees such as engineers, have already made them a highly sought-after group across other energy sectors, as well as in non-energy industries such as technology. As a result, even with recent waves of layoffs at the majors, many parts of the oil and gas industry are struggling to retain experienced employees and find suitably skilled new workers. Concerns including career security, instability associated with the boom and bust nature of oil and gas, and the energy transition have made some new workforce entrants hesitant to commit to a career in oil and gas companies, especially in advanced economies such as Europe and the United States. Those same factors have led an increasing number of oil and gas workers to express interest in moving out of the industry, with as many as 85% considering switching to another sector such as renewables or technology (Airswift, 2023). But possibly the most important cause of the skills shortage is the retirement of the oil and gas workforce, which is shrinking the availability of workers with relevant skills.

Figure 3.4 ▷ Employment in oil and gas supply by region and scenario, 2022 and 2030



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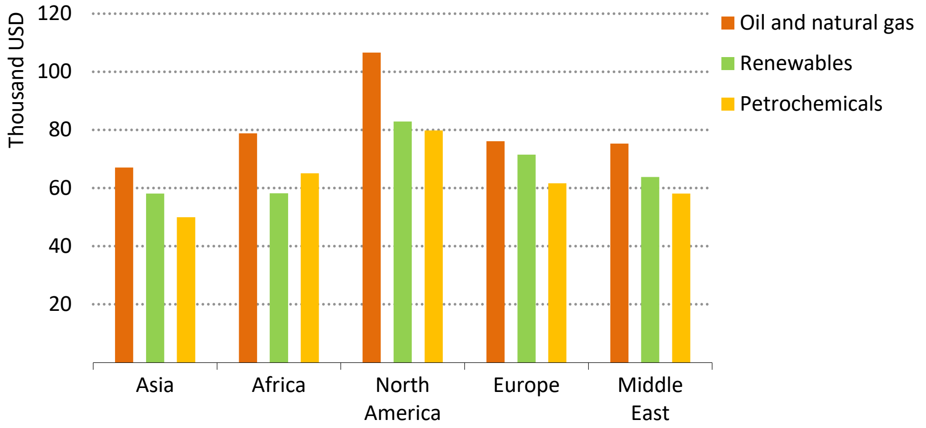
Employment in oil and gas supply decreases by the end of the decade in the APS and NZE Scenario, but the gas workforce shows greater stability.

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

Oil and gas companies have recently been increasing wages as they struggle to hire new staff and retain existing employees. Companies are also testing new recruitment and internal career paths to respond to professional expectations and the need for flexibility in future market developments.

The jobs created by the energy transition will not necessarily require the same skills, pay as much, or be in the same geographies as the jobs lost. Although energy jobs worldwide are, on average, better paid than the median national wages, workers in oil and gas tend to earn more than workers in less-established clean energy industries (Figure 3.5). In the United States, for example, the median hourly wage of oil and gas workers is around 75% greater than the economy-wide average, while the median for wind and solar workers is around 50% larger than the average. This can be attributed to a combination of factors, including the significant skill requirements for oil and gas work, high rents from oil and gas production, greater compensation for occupational hazards, instability and relocation, and the industry's well-established union representation.

Figure 3.5 ⊳ Average annual salary of permanent energy workers, by industry and region, 2023



On average, the renewables sector offers lower salaries than the oil and gas sector, a potential barrier to workers shifting between industries.

Note: Average annual salary of permanent workers based on six years' experience.
Sources: Airswift (2023).

3.3 Oil and gas company responses to date

A number of large oil and gas companies have made announcements on how they plan to respond to the increasing pressures they are facing. These vary widely in their nature, scope and ambition, and some previously announced goals were weakened following the 2022 energy crisis. The responses of companies can be broadly grouped into two main areas: plans to reduce scope 1 and 2 emissions from traditional oil and gas operations; and strategic moves to diversify and invest in areas outside their core businesses.[1]

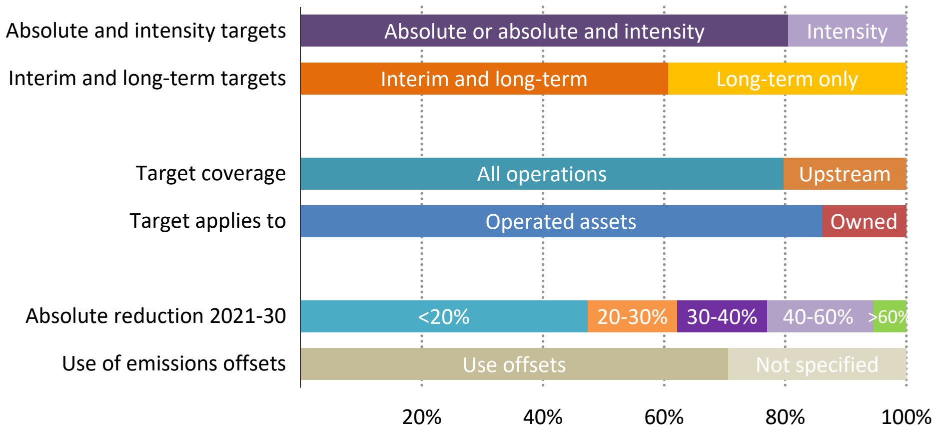
3.3.1 Targets to reduce scope 1 and 2 emissions

Our detailed analysis of 40 large oil and gas companies indicates that just under half of current global oil and gas output is produced by companies that have announced a target to reduce their scope 1 and 2 emissions. These targets have been expressed in many different ways. The majority are specified as a reduction in absolute emissions from operations rather than a reduction in the emissions intensity of operations (Figure 3.6). Around 40% of these

[1] Scope 1 emissions come directly from oil and gas operations; Scope 2 emissions arise from the generation of purchased energy. See Section 2.2 for further details on definitions.

companies have announced a target only for 2050; the other 60% have announced an interim target (for a date between 2025 and 2035) alongside a target for 2050.

Figure 3.6 ▷ Coverage and characteristics of company scope 1 and 2 emissions targets



Around half of the oil and gas produced today comes from companies with scope 1 and 2 targets, but these vary widely in their ambition and scope.

Note: Depicts share of oil and gas produced by companies with targets. For the absolute reduction 2021-30, reduction targets expressed as an emissions intensity reduction are converted to absolute reductions assuming stated production plans or production changes in line with history. Linear interpolation used to derive 2030 values when not given.

Sources: IEA analysis based on annual reports of 40 oil and gas companies representing more than 60% of global production; all other companies are assumed not to have a target.

Most companies indicate that their reduction targets cover only the emissions from directly operated assets and exclude emissions from assets in which they hold an equity stake (see Chapter 1). This approach reflects legal and contractual requirements to manage GHG impacts and most sustainability reporting frameworks do not require companies to report emissions from non-operated assets. This means a major source of emissions could be excluded from their targets. Some companies have therefore announced aims to use their influence to achieve reductions at non-operated assets.

Combining the above factors, we estimate that around half of the targets aim to reduce absolute emissions by less than 20% by 2030. Only 5% of the oil and gas produced by companies with targets – i.e. less than 2% of global oil and gas production – is covered by a target to reduce emissions by 60% or more to 2030 (the overall level of reduction in the NZE Scenario [Section 3.5.1]).

One critical issue for scope 1 and 2 emissions reduction targets – however they are specified – is the level of accuracy with which emissions are measured and how they are reported. One particular area of concern is methane emissions. Based on all publicly available methane emissions measurement studies, we estimate that oil and gas operations were responsible for around 80 Mt of methane emissions in 2022 (IEA, 2023b). This is much higher than implied by the emissions from company reporting. For example, a recent industry report – covering more than 20% of global oil and gas supply – indicated that around 0.5 tonnes of methane across the supply chain were emitted per tonne of oil equivalent of oil and gas production (IOGP, 2023). If these companies were to be fully representative of the industry globally, then global oil and gas methane emissions would be around 4 Mt, 95% lower than our estimate.

A number of companies have set out how they intend to cut emissions from their operations, including the investment that will be required. This includes investing in energy saving measures and materials, decarbonising electricity, and equipping facilities with carbon capture, utilisation and storage (CCUS). Three quarters of the companies in our sample indicate their intent to use emissions offsets to achieve their targets (Box 3.1).

Mergers and acquisitions have important implications for the way some oil and gas companies could look to achieve their scope 1 and 2 emissions reduction targets. For example, a company may decide to sell a high-emissions intensity asset rather than undertake direct efforts to improve its environmental performance. This takes on an additional dimension if the acquiring company has less stringent environmental conditions and chooses to operate it in a more emissions-intensive way. The transfer of the asset may help one company achieve its own emissions reduction targets, but it could lead to an overall increase in emissions globally. It is estimated that asset transfers from companies with environmental commitments to those without increased from 15% of the overall value of mergers and acquisitions in 2018 to 30% of the total value of deals in 2021 (EDF, 2023a).

Governments have a key role to play in preventing these perverse outcomes. Setting country-wide goals on emissions intensity or emissions reduction requirements would limit the risk of asset transfers leading to an increase in emissions. But companies themselves can also undertake efforts to avoid asset disposals leading to increased emissions. Examples of possible actions include: assessing the emissions targets of acquirers as part of the due diligence process before making a deal; making it clear how much of their company-wide emissions reductions are due to transfers as compared to direct emissions reduction efforts; and working with buyers to strengthen their emissions reduction targets and plans for asset decommissioning (EDF, 2023b).

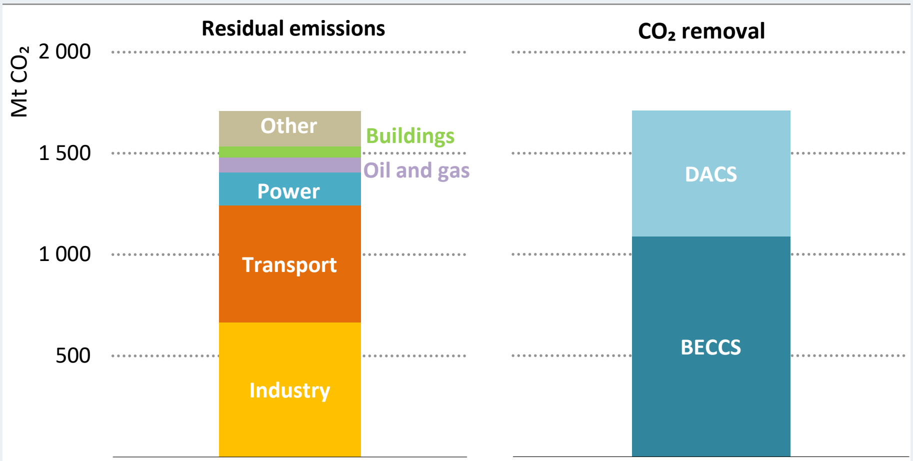
Box 3.1 ▷ Using carbon credits to meet emissions targets

Three quarters of the oil and gas companies with scope 1 and 2 emissions reduction targets have stated that they will use carbon credits to help them achieve their targets. The remainder have not specified how they will achieve their targets, but few have totally ruled out the use of carbon credits. Carbon credits can play a role in net zero transitions, but it is important to distinguish between projects that avoid, reduce or remove emissions:

- **Avoidance** credits are generated by projects that avoid emissions from an activity that would have otherwise caused emissions, e.g. avoiding deforestation or avoiding the extraction of fossil fuel reserves. These are highly dependent on the credibility of the counterfactual (in which the emissions would have occurred) and face the possibility that the emissions take place anyway.
- **Reduction** credits are generated by projects that directly reduce GHG emissions from existing activities, e.g. energy efficiency improvements, methane abatement or use of CCUS. There are likely to be few reduction credits generated in rapid net zero global energy transitions as there is limited scope to demonstrate additionality.
- **Removal** credits are generated through CO_2 removal technologies or nature-based solutions. The NZE Scenario sees 1.6 gigatonnes (Gt) of emission removals through direct air capture with CCUS (DACS) and bioenergy with CCUS (BECCS) in 2050 and no removal offsets from outside the energy sector.

The supply of high-quality carbon credits is struggling to keep pace with current demand. A number of questions have been raised around the integrity of many existing schemes, including addressing their long-term permanence, additionality, and the methods used to issue credits (Kreibich & Hermwille, 2021). In some cases, projects generating credits have also had negative impacts on local communities (Robinson, et al., 2016).

Figure 3.7 ▹ Residual emissions and CO_2 removal in the NZE Scenario, 2050



IEA. CC BY 4.0.

In the NZE Scenario, the oil and gas sector accounts for around 5% of total removals via DACS and BECCS in 2050 to offset its remaining emissions.

Notes: DACS = direct air capture with CCUS; BECCS = bioenergy with CCUS.

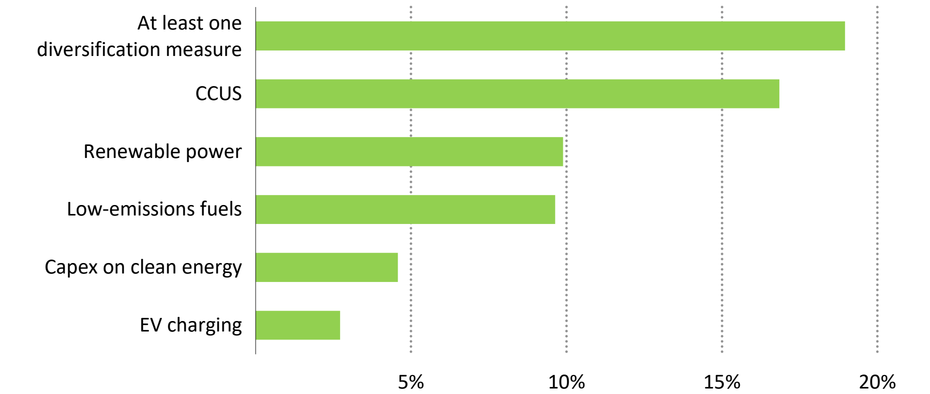
In the NZE Scenario, there is a 98% reduction in oil and gas sector scope 1 and 2 emissions to 2050 that is achieved without using any carbon credits. In 2050 remaining scope 1 and 2 emissions from oil and gas supply amount to 75 Mt CO_2, most of which is from refining. These emissions are offset through the use of DACS and BECCS and account for around 5% of total CO_2 removals in 2050 (Figure 3.7).

If oil and gas companies purchase removal carbon credits, this could help accelerate the development of negative emissions technologies more broadly. But the availability of quality credits is likely to be limited, and would only be consistent with the NZE Scenario once all efforts to realise real emissions reductions have been made. Given its existing skills and expertise, the industry could also look to develop negative emissions technologies itself and sell credits to generate an additional source of income.

3.3.2 Targets to diversify into clean energy technologies

Just under 20% of current oil and gas production comes from companies that have announced a target to diversify their activities into clean energy (Figure 3.8). A number of companies, including TotalEnergies, Equinor and BP, have pledged to invest a share of their capital budget in electricity and renewables, or low-emissions and zero-emissions options. Companies have also set specific capacity or spending targets for the deployment of technologies including CCUS, renewable power, bioenergy, low-emissions hydrogen and electric vehicle (EV) charging stations. In addition, eight companies have announced targets to reduce their scope 3 emissions. While there have been increasing calls on the industry to set such targets, they can have a number of potential drawbacks (Box 3.2).

Figure 3.8 ▷ Share of global oil and gas production from companies with diversification targets



Companies producing around 20% of oil and gas today have a target to diversify into clean energy; CCUS and renewables are the most frequently cited technology choices.

Sources: IEA analysis based on public reports of 40 companies providing 60% of global oil and gas production.

Box 3.2 ▻ The trouble with scope 3 targets

Different "scopes" of emissions are used to help companies distinguish between the various ways that their business activities can result in emissions. Scope 3 includes emissions caused before the company's activities (e.g. during the manufacture of the equipment it uses) and after (e.g. from the processing and use of sold products). For the oil and gas industry, the largest source of scope 3 emissions is the combustion of oil and gas by end-use consumers; this accounts for 80% of the life cycle emissions of oil and 85% of the life cycle emissions of natural gas. Eight oil and gas companies – including BP, Chevron, ENI, Equinor, Oxy, Repsol, Shell, and TotalEnergies – have announced scope 3 emissions reduction targets, and there have been calls for all companies to set targets for reducing scope 3 emissions.

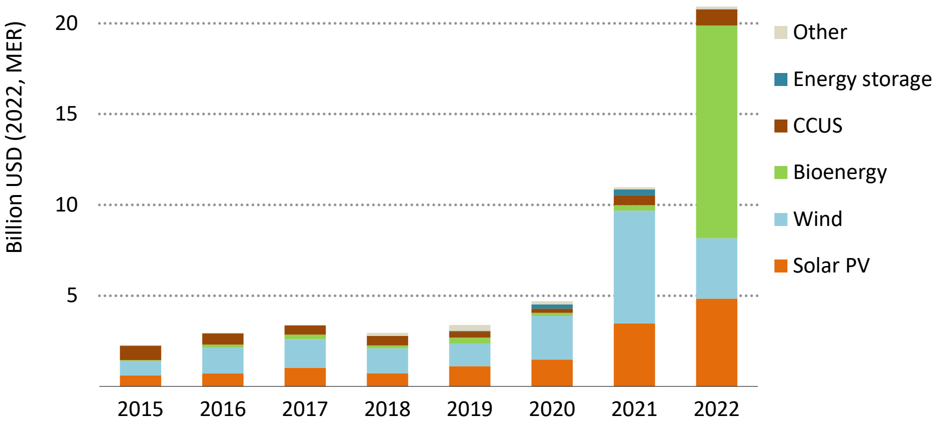
An oil and gas company can cut its scope 3 emissions in a number of ways, including: ensuring the oil and gas it produces, processes or transports is used with CCUS; ensuring it is used in a non-combustion activity (e.g. converted into plastic); or reducing the amount of oil and gas sold. If the company sets a target to reduce scope 3 emissions intensity, another option is to increase the proportion of lower-emissions energy sold.

Scope 3 emissions reduction targets can be a useful signal of a company's plans and how it intends to achieve these, but they could also lead to some perverse incentives that limits the real emissions reductions achieved. Targets relating to oil and gas production or on clean energy deployment are likely to be easier to operationalise, more transparent and align better with the overall needs of net zero transitions (Section 3.5). Some potential issues with scope 3 targets are:

- There is no clear designation of who should take the lead on reducing scope 3 emissions. Initiatives such as the Science-Based Target Initiative and Net Zero Banking Alliance have taken a variety of views: the producers can take responsibility, or the user of the product, or all actors along the value chain. Oil and gas companies can influence, anticipate and deliver on customer needs, but they are in general unable to dictate how end-use customers use their products.
- Scope 3 emissions are reported multiple times by different entities along the value chain. Oil produced by one company, refined by another, transported by a third, and sold to end-use consumers by a fourth would result in scope 3 emissions being reported for all four of the companies. Targets to cut down on scope 3 emissions may encourage companies to change the ownership of and responsibility for products to reduce emissions on paper, but without any real emissions reductions.
- A number of scope 3 emissions targets stipulated to date are combined reductions in scope 1, 2 and 3 emissions. Scope 1 and 2 commitments need to be ambitious and unambiguous to align with net zero transitions; combined scope 1, 2 and 3 targets risks diluting the importance of reducing a company's own emissions.

The oil and gas industry invested around USD 20 billion in clean energy technologies in 2022 through direct investment, mergers and acquisitions and joint ventures, and corporate venture capital (IEA, 2023a). This included investment in a wide range of technologies such as solar PV, onshore and offshore wind, geothermal power, biofuel or biogas production, hydrogen, EV charging, and CCUS.[2] Bioenergy accounted for more than half of the industry's clean energy spending in 2022 as a number of companies took major stakes in several bioenergy producers, with significant acquisitions by BP, Shell and Chevron (Figure 3.9).

Figure 3.9 ▹ Investment by the oil and gas industry in clean energy technologies, 2015-2022



Clean energy investment by oil and gas companies doubled in 2022 to around USD 20 billion, with companies taking major stakes in several bioenergy producers.

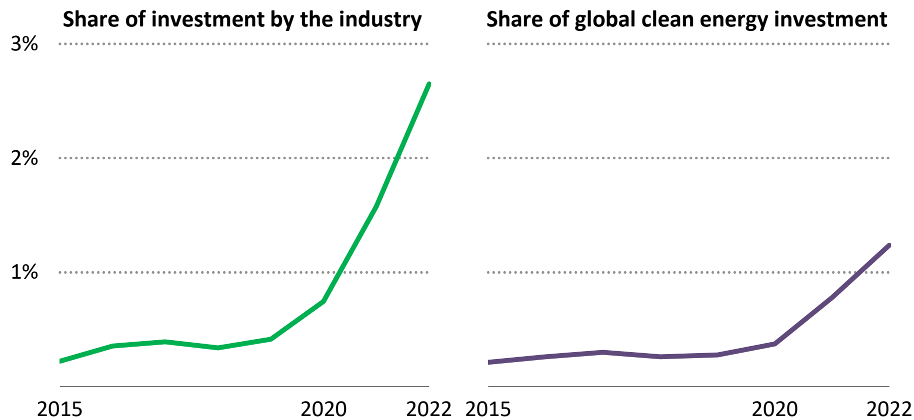
Note: Other include electrolysis and CCUS hydrogen as well as geothermal, small hydro and hybrid projects.

Sources: IEA analysis based on annual reports, Clean Energy Pipeline (2023), Rystad Energy (2023) and IJ Global (2023).

Clean energy investment by the oil and gas industry as a whole represented 2.7% of its total capital spending in 2022 and 1.2% of total investment in clean energy (Figure 3.10). More than 60% of this came from four companies: Equinor, TotalEnergies, Shell and BP, which spent each around 15-25% of their total budgets on clean energy. A number of companies spent much smaller shares (e.g. CNPC, Qatar Energy and ConocoPhillips), others indicate that they invest in clean energy but have not stated the amounts involved (e.g. ADNOC), and many have not provided any guidance on their levels of clean energy spending.

[2] The clean energy investment amounts reported here do not include investment in nature-based solutions, scope 1 and 2 emissions reduction measures, or other business activities, such as investment in retail sites.

Figure 3.10 ⊳ Clean energy investment by the oil and gas industry as a share of its total investment and of global clean energy investment



Clean energy investment by oil and gas companies has accelerated since 2019. In 2022 it represented 2.7% of total capital expenditure and 1.2% of global clean energy investment.

Sources: IEA analysis based on annual reports, Clean Energy Pipeline (2023), Rystad Energy (2023) and IJ Global (2023).

3.4 What could net zero energy companies look like in 2050?

The industry landscape is diverse and no single option will make sense for all, but oil and gas companies looking to align their portfolios with net zero transitions need to change. This section provides illustrative examples of how today's oil and gas companies would look if they chose to scale up clean energy activities and evolve their portfolios in line with trends in the NZE Scenario. An alternative approach – not examined here, but also fully aligned with the NZE Scenario – would be simply to wind down oil and gas operations in line with the overarching declines in oil and gas demand (see Section 3.5).

There are a number of major challenges that a company would face in practice when looking to achieve a major shift in its energy portfolio. In particular, inertia in shifting the corporate culture could significantly slow down or even prevent the wholesale reorientation of activities. For example, oil and gas activities have typically been associated with a high level of risk and reward and accompanied by a high degree of volatility in returns. Clean energy technologies in contrast often have more tightly controlled or regulated returns and so, while they may have a similar overall level of return on capital invested as oil and gas, they do not display such large year-on-year fluctuations and thus have fewer opportunities for windfall profits (see Box 2.2 in Chapter 2).

Some companies might therefore choose to restructure and spin off fossil fuel activities or new clean energy businesses, similar to the approach of several European electricity utilities in the 2010s. Alternatively, companies could look to scale up their clean energy portfolio by acquiring successful clean energy companies in the future. This wait-and-see approach also carries significant risks. The acquisition target may not be prepared to be a junior partner, it tends to be hard to merge large firms with very different cultures, and competition for any available firms is likely to be fierce.

Companies could also look to learn quickly about new technology areas through corporate venture capital (CVC) investment (Box 3.3). This may be especially useful in areas where the company has limited existing experience and would face difficulties launching its own new product line, and where there is the risk that new businesses would struggle for sufficient attention and tolerance within the corporate parent. CVC investment is typically used as a low-cost means of supporting start-ups that could become future acquisition targets, allowing them to operate initially outside the cultural constraints of the parent company.

Whichever strategy is used to transform in line with net zero transitions, profitability remains a crucial consideration and pursuing diversification strategies involves multiple risks. Companies could unwittingly acquire clean energy firms at inflated prices, choose underperforming technologies, invest in oversaturated markets, misread policy signals, or venture too far from their core areas of expertise so that they lose commercial advantages.

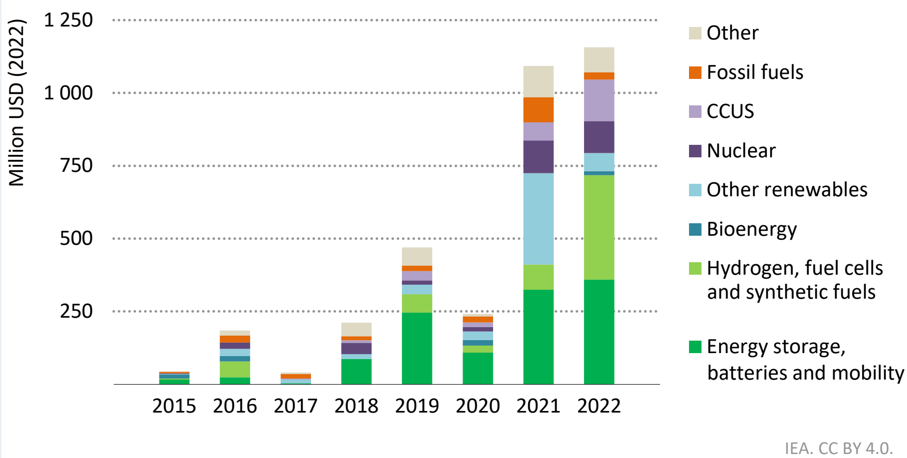
In this section, we provide illustrative energy portfolios in 2050 of different types of oil and gas company if they were to provide the same amount of energy, or support the same levels of energy service demands, in 2050 as they do today but in a manner consistent with the NZE Scenario.

Box 3.3 ⊳ Clean energy corporate venture capital spending by the oil and gas industry

Oil and gas companies' CVC investments in clean energy start-ups hit a record level in 2022 at USD 1.2 billion (Figure 3.11). The fivefold growth of CVC investment by the oil and gas sector since 2018 indicates a strategic evolution in their approach to technology.

As well as financial support, oil and gas companies can provide valuable access to testing facilities, customers and commercial networks. In 2021 and 2022, CVC growth was driven by hydrogen, CCUS and renewable energy technologies. The majority of this equity investment was in growth-stage start-ups that are bringing a tested product to market, with the biggest deals relating to CCUS, solar PV and synthetic fuels. Only 17% of the total was for riskier early-stage start-ups, where the deals were concentrated in energy storage, geothermal and hydrogen. Overall, the data indicate some opportunities for diversification, given that 60% of the funding went to US-based start-ups and only low shares went to innovators in areas such as bioenergy, wind and CO_2 storage, where oil and gas expertise will be critical for success.

Figure 3.11 ▷ Corporate venture capital investment by oil and gas companies in energy start-ups by technology area



The oil and natural gas industry has grown its CVC activity fivefold since 2018, with most investment in battery, EV, hydrogen and renewable start-ups.

Note: Includes early-stage and growth-stage investments, according to definitions used in IEA (2023a).

Source: IEA analysis based on Cleantech Group (2023).

3.4.1 A net zero "major" energy company

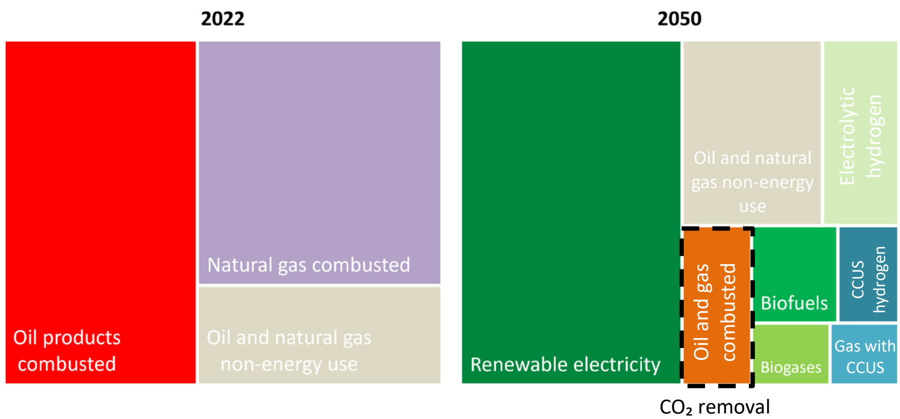
The seven oil and gas majors currently each produce on average 1.5 million barrels per day (mb/d) of oil and 65 billion cubic metres (bcm) of natural gas per year. One possible option to transition to be a net zero major energy company would be to continue to produce 1.5 mb/d of oil and 65 bcm of natural gas every year but to rapidly expand the use of CCUS and carbon removal to avoid the associated emissions. This would involve developing around 60 Mt CO_2 of CCUS capacity and around 200 Mt CO_2 of carbon removal capacity. This would require around USD 25 billion investment every year to 2050, which would be in addition to the USD 10 billion likely needed on average each year to maintain its oil and gas production levels. Mobilising this level of capital would be an immense challenge as it three-and-a-half times the annual average capital expenditure of the majors over the past five years (USD 10 billion). This approach is therefore likely an option only in theory for a major to transition to be a net zero energy company.

An alternative approach would be to grow a broader portfolio of low-emissions fuels and products in line with the trends of the NZE Scenario. The oil and gas produced by a major today provides the energy for around 250 billion vehicle kilometres, 8 Mt of primary chemicals, and thermal comfort, light and heat for 20 million homes, among many other service demands. If these same service demands were to be provided without any emissions, what might a net zero major energy company look like?

In 2050 in the NZE Scenario, oil and natural gas are still used in sectors where the fuels are not combusted – as in petrochemicals – and in facilities equipped with CCUS. The company would therefore still produce around 350 thousand barrels of oil per day (kb/d) and 6 bcm of natural gas in 2050. This would need to be accompanied by extensive efforts to cut scope 1 and 2 emissions.

A large portion of the company's energy portfolio in 2050 would consist of renewables (Figure 3.12). Over 300 gigawatts (GW) of renewables would be needed to replace some of the energy services currently met by oil and natural gas. Half of this capacity would be needed to provide electricity for EVs to support a similar level of passenger vehicle kilometres, a further 30% to support the rollout of electrolytic hydrogen production, and the remainder to produce power for other electrified energy service demands, such as household heat pumps to provide thermal comfort and industrial-scale electric motors to provide a range of manufactured products.

Figure 3.12 ▷ Example of major's energy production portfolio in 2050 aligned with changes in the NZE Scenario



A large oil and gas company would need to make significant efforts to diversify its energy supply to provide the same energy services in the NZE Scenario in 2050 as today

Notes: Blocks are sized by the contribution of each energy source and technology to meeting the energy service demands currently met by 1.5 mb/d of oil and 65 bcm of natural gas.

The company would produce around 12 billion cubic metres equivalent (bcm-eq) of low-emissions hydrogen produced from electrolysis or from natural gas with CCUS, as well as around 85 kboe/d of biofuels. It would capture and store 8 Mt CO_2 from oil and gas use and remove a further 12 Mt CO_2 from the atmosphere to offset residual emissions from remaining combustion of oil and natural gas.

On average, we estimate that it would cost just over USD 20 billion per year to 2050 for the company to undertake this full transformation of its energy portfolio, around twice the average annual capital expenditure of an oil and gas major in recent years. By 2050, less than 10% of capital investment would be to sustain existing oil and gas operations, and the remainder would be allocated to clean energy.

3.4.2 A liquids-focused national oil company

Companies could also choose to focus on their core strengths, rather than diversify into new business areas. For example, a company might decide to retain a focus on liquids production, processing and transport, leveraging its existing assets while building up new capabilities to produce low-emissions fuels such as liquid bioenergy and low-emissions hydrogen-based fuels (Figure 3.13). Here we examine what a company portfolio could look like if it continues to provide a similar level of liquids to the market as it does today.

This route may be attractive for some vertically integrated NOCs with a strong presence across the upstream, midstream and downstream parts of the oil value chain. The group of NOCs and INOCs encompasses a wide variety of companies, but the 20 largest liquids-focussed NOCs on average produce around 2 mb/d of crude oil and natural gas liquids. Most process this in their own refineries and petrochemical plants. On average around 60% of refinery output by volume is gasoline and diesel, 15% is fuel oil and kerosene, and a large part of the remainder is feedstock for use in the petrochemical sector.

In the NZE Scenario, 35.5 mboe/d of liquids are consumed in 2050, comprising 24 mb/d of oil and 11.5 mboe/d of liquid biofuels and low-emissions hydrogen-based fuels. This level of liquids demand in 2050 is two-thirds lower than in 2022 and so a company looking to continue deliver 2 mboe/d of liquid fuels through to 2050 would boost its overall share of the market from about 2% in 2022 to 6% in 2050.[3]

Around 65% of liquids portfolio in 2050 of an NOC looking to evolve in this way would still consist of oil products but the types of products produced would change dramatically. Gasoline, diesel, and fuel oil would shrink to less than 15% of total output in 2050, and the share of petrochemical feedstocks and other non-combusted oil products would increase to almost 80% (including products that are supplied by fractionating natural gas liquids). This would require investment to reconfigure refineries and to ensure scope 1 and 2 emissions are minimised along the oil supply chain.

The other 35% of the NOC liquids portfolio would consist of low-emissions liquid fuels. This would include 170 kboe/d of advanced biofuels for road transport and 150 kboe/d of biojet kerosene. It would also produce 200 kboe/d of ammonia for use in the power sector and in shipping and 180 kboe/d of low-emissions hydrogen-based kerosene for aviation. A

[3] It would not be possible for all NOCs to increase their market share in this way as the space narrows considerably in the NZE Scenario.

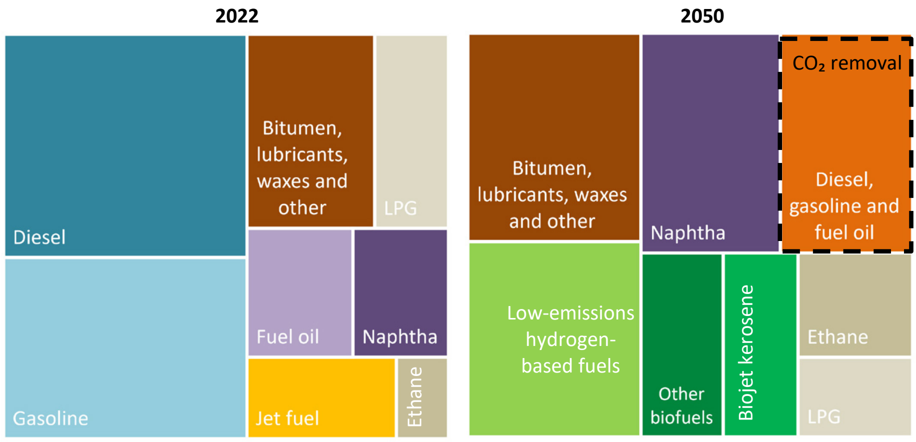
successful foray into this area would be contingent on the sourcing and processing of several million tonnes of sustainable feedstocks and the construction of capacity that can produce 8 Mt each year of low-emissions hydrogen.

The large NOCs also possess infrastructure, such as depleted oil and gas fields, that is amenable to being repurposed for CO_2 or hydrogen storage. This could be used to help an NOC offset residual emissions from its production portfolio. The NOC would own around 5 Mt CO_2 of CCUS capacity for oil use in industry and a further 50 Mt of CO_2 removal capacity (meaning close to 55 Mt CO_2 of CCUS capacity in total).

3

We estimate that the NOC would need to invest about USD 15 billion on average each year to 2050 to undertake this transformation of its energy portfolio. By 2050, around 20% of its capital expenditure would be in oil supply, maintaining and transforming oil refineries, and reducing scope 1 and 2 emissions. The remainder would be invested in low-emissions fuels and products (55%) and investment in carbon removal (25%). This overall level of investment is around two-and-a-half times the USD 5.5 billion average annual capital investment in oil production of the 20 largest NOCs in recent years, highlighting the challenges that would be face to maintain its production levels but grow its share of the liquids market. To maintain the same level of net income as it generates today while covering the additional capital costs of developing low-emissions liquids, the NOC would need to receive around USD 200/boe for low-emissions hydrogen-based fuels and liquid biofuels sold in 2050.

Figure 3.13 ▷ Example of changes in a liquids-focused NOC aligning its energy production portfolio with the NZE Scenario in 2050



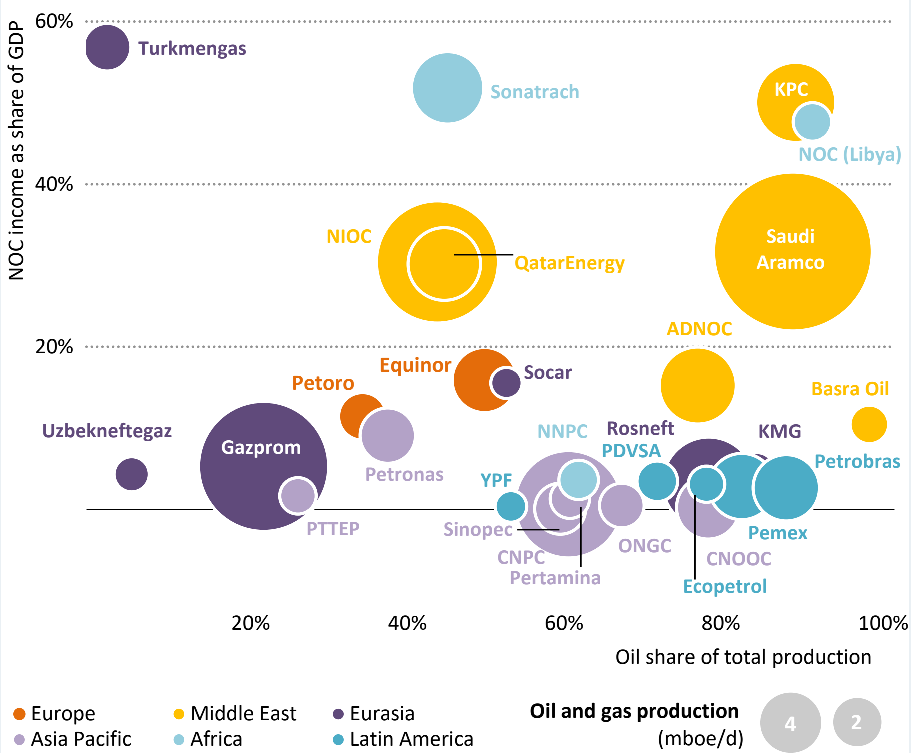
A liquids-focused NOC could retain some traditional assets to produce oil products for petrochemicals and non-energy use, while diversifying into biofuels and synthetic fuels.

Notes: 2022 and 2050 blocks represent 2 mboe/d of liquids production.

Box 3.4 ▹ The pivotal role of NOCs and INOCs in net zero transitions

The group of NOCs and INOCs encompasses a wide variety of companies with very different roles, governance, sizes, operations, and contributions to their domestic economies (Figure 3.14). Nonetheless, they are all critically important stakeholders in their host countries and will also be critical to efforts to achieve net zero transitions, both domestically and globally.

Figure 3.14 ▹ NOC and INOC oil and gas production, oil as a share of total production, and net income as a share of GDP, 2022



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NOCs and INOCs are a diverse group, with different starting points and approaches to transitions. Many are pivotal to their host country's economies.

Notes: ADNOC = Abu Dhabi National Oil Corporation; CNOOC = China National Offshore Oil Corporation; CNPC = China National Petroleum Corporation; KMG = KazMunayGas; KPC = Kuwait Petroleum Corporation; NIOC = National Iranian Oil Company; NNPC = Nigerian National Petroleum Corporation; NOC (Libya) = National Oil Corporation (Libya); ONGC = Oil and Natural Gas Corporation (India); PDVSA = Petróleos de Venezuela, S.A; PTTEP = PTT Exploration and Production (Thailand).

Source: IEA analysis based on Rystad Energy (2023).

The profits made by NOCs and INOCs have helped governments to finance a great deal of public spending, while supporting public infrastructure investments and employment. This could be threatened by the drops in oil and gas revenues that occur in net zero transitions (see Chapter 4). To date, most of the large NOCs have responded to the challenge of net zero transitions by emphasising their role as custodians of national hydrocarbon resources, with an enhanced focus on supplying the oil and gas with the lowest possible emissions intensity.

Very few NOCs have been charged by their host governments with leadership roles in renewables or other non-core areas. The predominant model thus far is for hydrocarbon-rich countries to create separate companies and public initiatives focussing on clean energy, leaving the NOC to focus on oil and gas. But the possibility that NOCs may also take on roles in relation to low-emissions technologies cannot be excluded, not least because of the possible synergies with their oil and gas operations. Some forward-looking NOCs and INOCs as well as those with dwindling oil and gas reserves are indeed accelerating efforts that target models of resource development compatible with net zero transitions. These cover a range of areas, including CCUS, hydrogen, biofuels, strategies to find and develop non-combustion uses for hydrocarbons as well as diversification into clean electrification, through investment in renewables, grids and electric vehicles.

3.4.3 An independent focused on gases

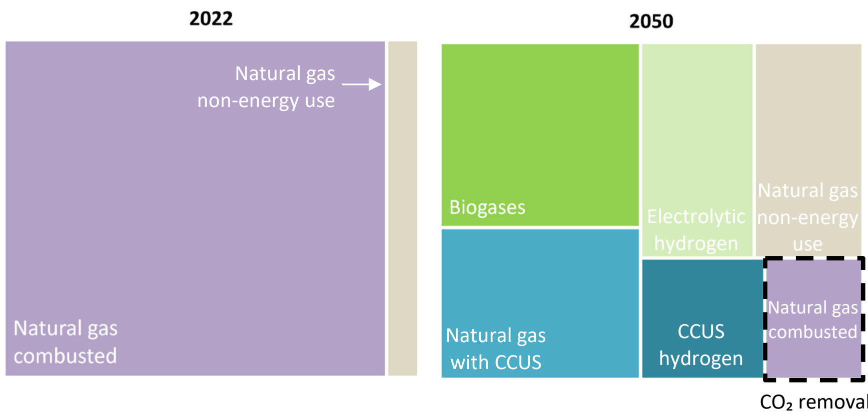
A number of independent companies focus almost exclusively on producing natural gas: these "pure-play" gas-focused independents are prevalent in North America, and they produce anywhere in the range of 5-60 bcm of natural gas, mostly from shale gas plays. Here we look at how the portfolio of a company that currently produces 20 bcm of natural gas might look in 2050 if it seeks to maintain this level of production of gaseous fuels to 2050.

In the NZE Scenario, natural gas demand falls by close to 80% between 2022 and 2050 while overall demand for gases falls by 55% to 2050. An independent looking to maintain 20 bcm of production would therefore need to diversify into biogases, hydrogen, synthetic methane and, given infrastructure synergies, CO_2 capture, transport and storage. This would roughly double the share of the overall gases market by 2050.

Around 60% of the 2050 production portfolio of the independent would be natural gas, 25% would be biogases, and 15% would be electrolytic hydrogen. Of the 12 bcm natural gas that it produces in 2050, around 40% would be used in the power and industry sectors where the CO_2 emissions are captured, 25% would be used in processes where the gas is not combusted, and 15% would be combusted and offset through the use of carbon removal. The remaining 20% would be converted into low-emissions hydrogen through the use of CCUS (Figure 3.15).

Combined with the electrolytic hydrogen and biogases that it produces, this means that around half of the energy delivered by the independent to end-use consumers would be low-emissions gases (some of this hydrogen may be further transformed into low-emissions hydrogen-based fuels). Most of the biogas produced would be upgraded to biomethane as a drop-in substitute for natural gas, for use in transport or injected into remaining gas transmission and distribution infrastructure.

Figure 3.15 ▷ Example of changes in a gas-focused independent aligning its energy production portfolio with the NZE Scenario in 2050



A gas pure player could orient its business model towards hydrogen, biogases and CCUS, while maintaining a pivotal role for natural gas production.

Note: Blocks represent 20 bcm-eq gases production. Natural gas combusted with CCUS includes gas captured in power and industry and the losses incurred in producing hydrogen with CCUS.

There are opportunities for a gas-focused player to integrate value chains across the spectrum of natural gas, hydrogen, synthetic methane and biogas production. For example, CO_2 captured from the process of producing hydrogen from natural gas or from the upgrading of biogas to biomethane could be used as an input into the production of synthetic methane (although using fossil CO_2 would require the capture of emissions from combusting the synthetic methane at the point of use and, in the NZE Scenario, low-emissions synthetic fuels are made with carbon recovered from CO_2 captured from bioenergy or the air). Although production costs are higher, synthetic methane or biomethane could employ the same infrastructure used to transport natural gas, including LNG terminals, without modification. There are also options to utilise natural gas infrastructure for hydrogen transport and storage (see section 2.2.5).

In the NZE Scenario, greater differentiation of gas according to its emissions intensity is likely to be a feature of international gas trade. Already today regulatory efforts in the United States and Europe are underway to enhance the measurement, reporting and verification of emissions associated with gas, particularly methane. An independent gas producer with a 20 bcm supply portfolio is likely to need to invest around USD 50 million on average each year to reduce its scope 1 and 2 emissions. This would include efforts to reduce methane emissions with enhanced leak detection and repair programmes, eliminating flaring, and electrification of midstream operations, such as gas pipeline compression or LNG liquefaction.

Overall trade of natural gas declines by around 80% between 2022 and 2050 in the NZE Scenario but gas players could still benefit from having trading divisions that commoditise a more diverse portfolio of fuels and technologies besides natural gas, such as hydrogen, biogases, CO_2, and carbon credits. In recent years trading houses and the trading divisions of majors and NOCs have accounted for a large share of total profits from oil and gas sales.

We estimate that the overall cost to transition to this low-emissions gas portfolio in 2050 would be around USD 3.5 billion per year. Around one-quarter of this would be for natural gas production and to reduce the emissions intensity of supply, half would be to develop low-emissions hydrogen, the associated CCUS capacity, and biogases, and the remaining one-quarter to develop the carbon removal capacity needed to offset unabated natural gas (around 8 Mt CO_2). This is a substantial increase from the USD 1.1 billion that an independent gas player with a 20 bcm gas supply invests on average each year currently. We estimate that to maintain the same level of net income as it generates today while covering the additional capital costs of developing low-emissions gases, the independent gas producer would need to sell low-emissions hydrogen and biogases for an average price of USD 20/Mbtu in 2050.

3.5 Assessing alignment with net zero transitions

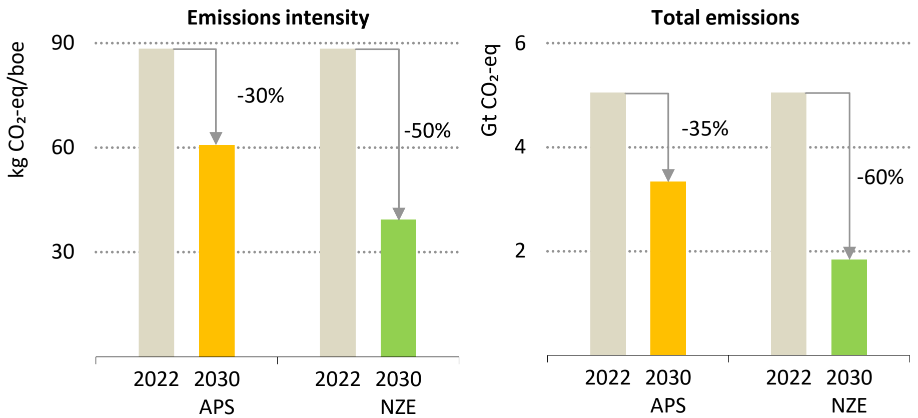
In this section we explore how oil and gas companies can play an active part in supporting net zero transitions. Benchmarks based on the APS and NZE Scenario cannot capture all the specifics of the wide range of oil and gas companies that exist. Nonetheless, they provide a broad guide for the industry as a whole as well as for individual companies looking to play their part in achieving net zero transitions. Here, we focus on the targets that need to be set – and achieved – by 2030 given the importance of immediate action to keep net zero goals within reach.

3.5.1 Emissions from own operations

In the APS, the global average scope 1 and 2 emissions intensity of oil and gas supply falls by around one-third between 2022 and 2030 and the absolute level of emissions falls by a similar amount (see Chapter 2). In the NZE Scenario, the global average emissions intensity falls by more than 50% to 2030 and total emissions fall by more than 60% in this period (Figure 3.16).

These figures provide an overarching guide to the reductions required of the oil and gas sector as a whole to 2030. To build confidence in the actions being taken, a consistent and transparent approach is also needed to monitor, report and verify emissions from oil and gas activities. This should be based on robust measurements to improve the accuracy and availability of emissions data. Companies can nonetheless do a lot even if they do not yet have a firm understanding of the emissions from their operations. Actions to stop non-emergency flaring, adopting a zero tolerance approach to methane emissions, and setting targets for electrifying operations, among many others, would cut emissions even as a company looks to improve measurement and reporting.

Figure 3.16 ▷ Scope 1 and 2 emissions intensity of oil and gas operations in the APS and NZE Scenario and total emissions in 2022 and 2030



Emissions from oil and gas operations fall by around one-third in the APS and by more than 60% in the NZE Scenario between 2022 and 2030.

Notes: Gt CO_2-eq = gigatonnes of carbon dioxide equivalent; kg CO_2-eq/boe = kilogrammes of carbon dioxide equivalent per barrel of oil equivalent.

A number of companies have already undertaken major efforts to cut emissions from their own operations and have emissions intensities far below our estimate of global averages (Table 3.1). Examples of the best practices from facilities or operations that exist currently for the largest sources of scope 1 and 2 emissions are:

- Extraction and processing, for example Equinor's operations in Norway. These operations have reduced methane leaks to very low levels and avoid flaring in all but emergency situations, and many operations have been electrified with low-emissions power.
- Refining, for example the Sturgeon Refinery in Canada. It captures CO_2 from operations, including hydrogen production, and sells the captured CO_2 for enhanced oil recovery or permanent storage, which reportedly reduces refining emissions by up to 70%. Shell announced plans that it will build a 200 MW electrolyser in the Netherlands to produce hydrogen using offshore wind, part of which will be used to replace high-emissions hydrogen in its refinery.

- LNG liquefaction, for example Freeport LNG. This has electrified operations using grid power with a high share of low emissions sources (rather than using natural gas to power operations).

The best-performing companies can help reduce scope 1 and 2 emissions elsewhere by providing technical, operational and financial assistance, particularly at non-operated assets. Nonetheless, if companies already have a low level of emissions from the oil and gas they own, it would be unreasonable to expect further large-scale reductions to achieve the industry-wide reductions needed to meet the NZE Scenario.

There are large differences between the scope 1 and 2 emissions self-reported by companies and the estimated level of emissions from publicly available measurement studies, particularly for methane emissions (see Section 3.3.1). Nonetheless, the reduction in total scope 1 and 2 emissions in the NZE Scenario to 2030 is broadly equivalent to the reductions that would be achieved if oil and gas producers around the world in 2030 were to perform in line with the emissions intensity of the best operators today.

If companies already reliably and transparently measure and report emissions from the oil and gas they own or process, they could be deemed to align with net zero transitions if, for the parts of the value chain they operate in, they achieve performance consistent with current best practices by 2030.

Table 3.1 ▷ Average emissions intensity and best practices of projects currently in operation or under construction

	Current average (kg CO_2-eq/boe)	Best practice (kg CO_2-eq/boe)	Example of best practice
Oil			
Upstream	60	8	Equinor operations in Norway (Equinor, 2022)
Refining	35	20	Most efficient medium conversion oil refinery (Jing, et al., 2020)
Natural gas			
Upstream	43	8	Equinor operations in Norway (Equinor, 2022)
LNG liquefaction	35	2	Freeport LNG (Freeport LNG, 2022)

Notes: Upstream is emissions from extraction and processing. Processes included here cover nearly 90% of our estimate of total scope 1 and 2 oil and gas emissions. Current average values are based on IEA estimates (see Chapter 2) and best practice values are reported by companies or in the scientific literature. Emissions from pipeline gas transport and crude oil and oil product trade are currently a function mainly of distances travelled and so are not included here.

3.5.2 Investment in clean energy

Large reductions in scope 1 and 2 emissions are a necessary condition for the oil and gas industry to align itself with net zero transitions. But changes need to be broader than this and some companies are making the case that they can play a constructive role in the necessary scaling up of clean energy. A critical question is what level of investment or share of their overall capital budget would be reasonable to align with net zero scenarios. There are no simple answers – it is impossible to capture the full diversity of options and nuances for individual companies in long-term energy scenarios – but the overarching investment trends of the APS and the NZE Scenario provide useful guidelines for a more informed, data-led discussion.

In practice, oil and gas companies take strategic direction from governments and shareholders, who may be better placed than oil and gas company executives to efficiently allocate capital towards clean energy by employing the proceeds of taxes, royalties and dividends toward clean energy initiatives. The degree of alignment of individual oil and gas companies with the NZE Scenario is therefore likely to be dictated by the preferences of these actors.

Moreover, companies will make different investment decisions based on their portfolio of assets, available resources, assessment of diversification opportunities, corporate culture and business models. For example, the majors tend to focus on their future market value and are governed by the interests of shareholders, which in some cases may demand action to mitigate climate risk to the business. Independent "pure-play" upstream companies typically exhibit a higher risk tolerance and seek higher returns from upstream investments. They may prioritise the optimisation of their upstream portfolio by divesting non-core assets and reinvesting in projects that offer the most promising growth prospects. In contrast, NOCs typically focus on the development of domestic oil and gas reserves, but may also invest in regions that strengthen diplomatic ties or national industrial or development priorities. Pressures or incentives to pursue low-emissions development pathways may be assessed in this broader context.

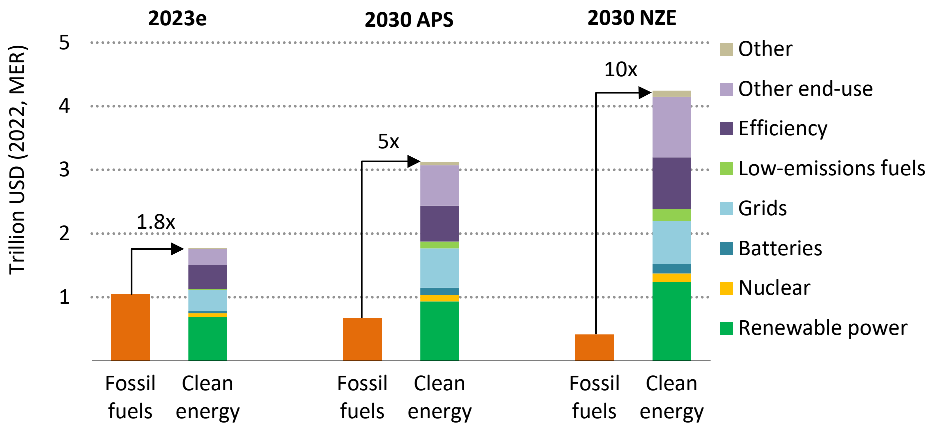
We explore below a pathway for oil and gas companies that explicitly want to transform and broaden their core competencies in line with the pace and scale of net zero transitions.

Economy-wide approach

In net zero transitions, reductions in fossil fuel investment need to be sequenced carefully so they do not run ahead of the necessary scale-up in clean energy technologies. In 2023 it is expected that around USD 1 trillion will be spent on fossil fuels and USD 1.8 trillion on clean energy technologies, meaning the ratio of investment in fossil fuels to clean energy is currently 1:1.8. By 2030 this increases to 1:5 in the APS and to 1:10 in the NZE Scenario. In the NZE Scenario, 60% of clean energy investment is on clean energy supply (low-emissions fuels and power) and 40% is on efficiency and clean end-use technologies (Figure 3.17).

These economy-wide ratios provide an important guide for financial actors looking to assess their equity and lending portfolios against net zero targets. But they are not directly relevant for oil and gas companies. This is because a large share of the clean energy investments in net zero transitions will need to be undertaken by end users (such as household spending on EVs and heat pumps, or energy-intensive industrial plants investing in retrofits or electric motors). The oil and gas industry itself has little presence or influence over investment choices in many of these areas and so it would be unreasonable to expect it to take a leading role in scaling up investment in these areas. These end-use investments could be excluded from the ratio, but this would mean closing off some clean energy investment choices for oil and gas companies, such as EV charging infrastructure or CCUS in industrial applications. Comparing oil and gas investment just to clean energy supply (a ratio of 1:6 in 2030 in the NZE Scenario and 1:3 in the APS Scenario) would suffer from similar limitations, and yield only a partial picture of the necessary investments undertaken across the energy economy.

Figure 3.17 ▷ Global energy investment spending in the APS and NZE Scenario



The ratio of investment in fossil fuels to clean energy rises from 1:1.8 today to 1:5 in the APS and to 1:10 in the NZE Scenario in 2030.

Note: 2023e = estimated values for 2023.

A more operational approach to assessing the compatibility of investment decisions by oil and gas companies with net zero transitions is to consider the industry's future financial resources and its ability to invest in clean energy, which can be determined as much by the strategic preferences of oil and gas company management as the political priorities of governments and financial and non-financial imperatives governing shareholder action. The balance that is struck invariably affects how much capital oil and gas companies would be able to allocate to diversification, taking into account expectations of future revenue and the continued need to invest in oil and gas. Here we examine what this might look like in the NZE Scenario.

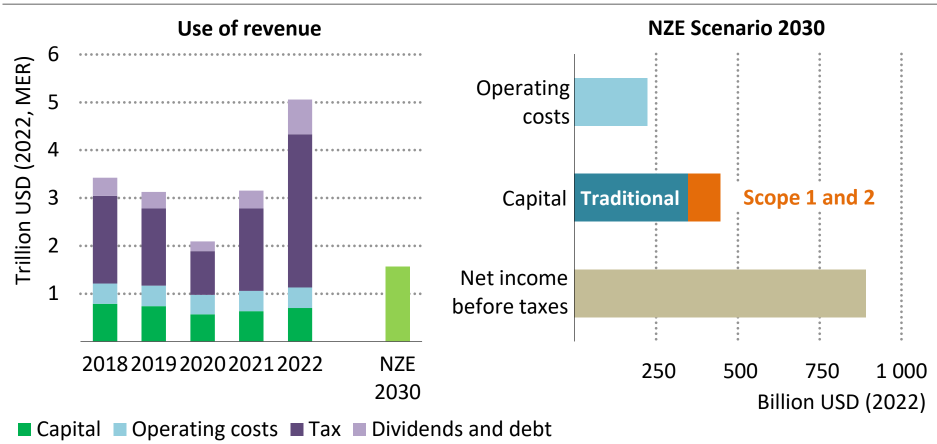
How much capital is available for the oil and gas industry to invest in clean energy in the NZE Scenario?

Between 2018 and 2022, the oil and gas industry earned, on average, close to USD 3.5 trillion each year in revenue. Around 50% of this was paid to governments in the form of taxes and royalties or retained as part of NOC domestic income, and 10% of total revenue was paid to shareholders in the form of dividends or buybacks and to pay down debt. The remaining revenue was used to cover capital and operating expenses, most of which were incurred in exploration, development and production.

In 2022, total capital expenditure by the industry was USD 700 billion, of which USD 20 billion went to clean energy (2.7% of the total). In the future, the level of capital that the industry could direct towards clean energy will depend on the future spending requirements for oil and gas and the extent to which governments and shareholders might be willing to accept lower returns to enable oil and gas industry transitions. Currently, there does not appear to be a large appetite among these stakeholders to forego these revenue streams.

In the NZE Scenario, around USD 1.6 trillion of gross oil and gas revenue is generated in 2030. Capital expenditure on oil and gas (USD 350 billion) and operating expenditure (USD 220 billion) are required to maintain supply, fund near-field extensions to existing fields, pay for equipment and infrastructure, transport and processing, and cover marketing and distribution costs. Reducing scope 1 and 2 emissions requires around USD 85 billion annual spending in 2030. This leaves USD 900 billion revenue in 2030 (Figure 3.18).

Figure 3.18 ▹ Distribution of oil and natural gas revenue in the NZE Scenario



Oil and gas industry revenue is USD 1.6 trillion in 2030. All of the net income before taxes could be spent on clean energy but this leaves no income for government or shareholders.

Note: Traditional capital spending is investment in maintaining production and operations at existing upstream and midstream oil and gas assets.

If shareholder payouts and government taxes as a percentage of total revenue remain at historical levels, of the USD 900 billion the oil and gas industry would have no remaining capital to spend on clean energy in 2030 in the NZE Scenario, given far lower prices and demand for oil and gas. This would mean that the share of capital spending on clean energy by the oil and gas industry would likely remain at a very low level.

Alternatively, if governments around the world were to lower tax takes to zero, and shareholders accepted no payouts from oil and gas sales, all the remaining USD 900 billion income could be devoted to clean energy investment. This would mean that for every USD 1 of capital expenditure on traditional oil and gas activities, almost USD 3 could be invested in clean energy. [4] In other words, nearly 75% of the capital spending by the oil and gas industry in 2030 could be on clean energy but this would rely on no income from oil and gas sales going to government or shareholders.

There is no single way to strike a balance between these two extremes and the situation is likely to vary markedly between individual companies and jurisdictions. Governments and companies would need to work together if the industry is to generate the cash flow necessary to sustain the investment required in oil and gas, while boosting new low-emissions activities and providing sufficient revenues to governments and returns to shareholders.

Here is an illustration of how oil and gas revenue in 2030 could be used in the NZE Scenario: if the government tax take from oil and gas revenue falls to 35% and shareholders accept lower direct cash distributions of 5% of gross revenue, this would leave governments with USD 600 billion and shareholders with USD 70 billion in 2030. After operating costs and investment to cut scope 1 and 2 emissions, this would leave around USD 600 billion revenue from oil and gas sales. A steady ramp-up in clean energy spending would also provide additional revenue, meaning the capital budget available to the oil and gas industry in 2030 would be closer to USD 700 billion. With USD 350 billion of capital investment in oil and gas required in the NZE Scenario in 2030, around USD 350 billion would be left to invest in clean energy. In other words, 50% of the oil and gas industry's capital expenditure, outside scope 1 and 2 emissions reductions, would be on clean energy (Figure 3.19).

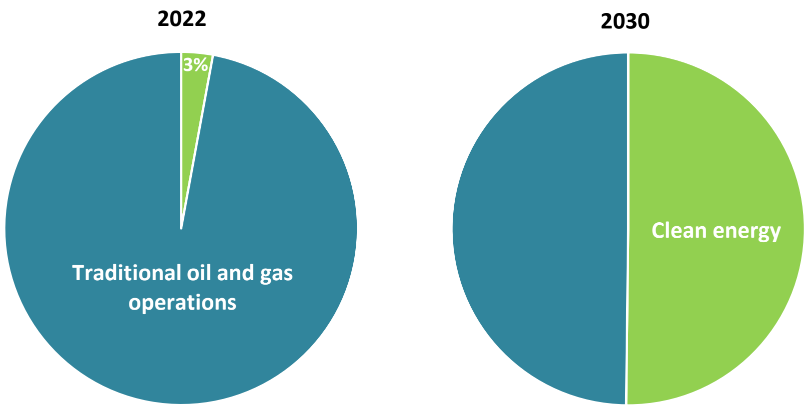
If the oil and gas industry were to follow this path, total capital expenditure in 2030 – around USD 700 billion – would be comparable to its annual average capital expenditure between 2018 and 2022. Clean energy investment of USD 350 billion would mean that the oil and gas industry contributes around 8% of all investment in clean energy in 2030 in the NZE Scenario, up from just over 1% today.

The analysis does not prejudice the choices individual companies may decide to make in net zero transitions, nor preclude the option to wind down operations. Indeed, the sharp reduction in the profitability of selling oil and gas in the NZE Scenario – which would be likely to lead to increased risk premiums attached to continued investment in oil and gas – could make it more challenging for the oil and gas industry to raise the capital necessary to diversify into clean energy. In the NZE Scenario, if governments do not change oil and gas fiscal regimes to give companies more space to invest in clean energy, it may be difficult for them to do so unilaterally. Strategies such as asset sales or accessing debt markets may free up additional capital to invest in clean energy, but many oil and gas companies may also see

[4] Investment in traditional oil and gas activities excludes operating costs and investment in scope 1 and 2 emission reductions.

operational improvements and a focus on higher-return core assets as a better recipe for long-term profitability than investing elsewhere in energy.

Figure 3.19 ▷ Indicative clean energy and traditional fossil fuel investment by the oil and gas industry in the NZE Scenario



In the NZE Scenario, it is possible for oil and gas companies to strike a balance between the interests of government and shareholders by investing 50% of capital in clean energy.

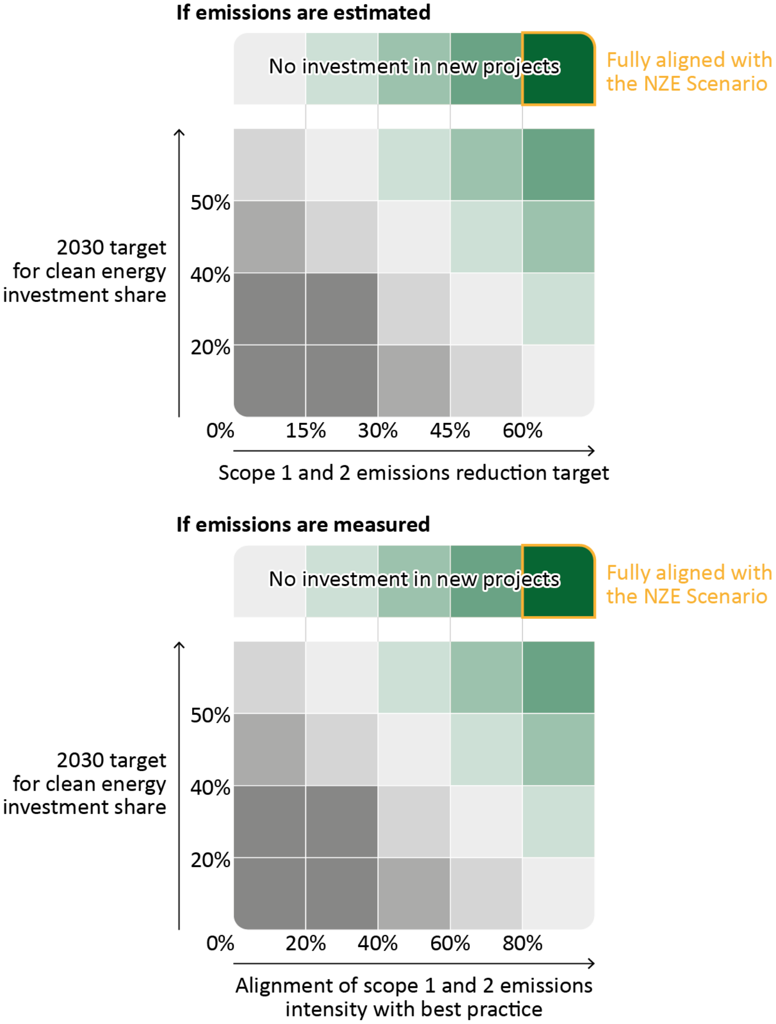
Note: Excludes capital expenditure on reducing scope 1 and 2 emissions in 2030.

Achieving a clean energy investment share of 50% would require all stakeholders – governments, companies, shareholders and financial actors – to work closely together and agree on the way forward. Governments need to put in place clear policy frameworks for net zero transitions that demonstrate the path ahead and allow companies to plan for change. But leading companies and their owners also have a voice in the energy and climate debate. They have the capacity to push for some of the certainty that they are looking for: signalling their ambition by setting firm near-term targets in line with net zero goals and taking steps towards achieving these is a vital step in the process.

3.6 Framework to assess the alignment of company targets with the NZE Scenario

Oil and gas companies face inevitable and wide-ranging changes if the world is to achieve its climate targets. Some are responding, but the wide array of approaches has led to confusion and ambiguity over how meaningful these actions really are. In this section, we present a new framework for quantitatively and qualitatively assessing the alignment of company actions and targets with climate goals.

Figure 3.20 ▻ An IEA framework for assessing alignment of company targets with the outcomes of the NZE Scenario



The new IEA framework allows for a more granular assessment of oil and gas company targets and their alignment with net zero transitions.

Notes: "Scope 1 and 2 emissions" include emissions from operated and non-operated assets but excludes reductions achieved through carbon credits purchases from outside the energy sector. "Best practice" metric assesses the alignment of 2030 targets for upstream and downstream activities with the lowest emissions intensities achieved by an operator today. It is weighted according to the company's level of emissions from each activity and is relevant only if a significant proportion of the emissions from the oil and gas it owns are measured. "Clean energy investment share" is total capital investment in clean energy technologies divided by total capital investment, with both values excluding investment in scope 1 and 2 emissions reductions and carbon credits generated from outside the energy sector.

Given the wide range of possible ways to achieve net zero emissions globally, this framework cannot cover every eventuality. It nonetheless aims to provide a more granular and data-led discussion on whether oil and gas companies are "playing their part" in accelerating net zero transitions. Fundamental to this is recognition that the diversity and complexity of the industry means an approach based on companies being "fully aligned" or not with climate targets is too simplistic.

The framework does not look to impose on companies any singular approach to net zero transitions. Rather it draws on the trends and insights from the NZE Scenario to highlight the actions and targets that would align with the net zero pathway described in that scenario. The key results from the NZE Scenario are the need to minimise the emissions intensity of core oil and gas operations, that no new long lead time conventional upstream projects are needed, and the importance of scaling up clean energy investment.

This does not mean, however, that companies have to diversify into clean energy to be aligned with the NZE Scenario. For example, some companies may take the view that their specialisation is in oil and natural gas and so decide that – rather than risking money on unfamiliar business areas – others are better placed to allocate this capital to new activities. Their "investment" in transitions would consist of returning cash to shareholders. Even though they make no direct investment in clean energy, their activities would still be fully aligned with the trends of the NZE Scenario if their scope 1 and 2 emissions are as low as possible and they do not invest in new long-lead time upstream conventional projects.

3.6.1 Framework overview

The IEA's new framework focuses on the targets that oil and gas companies have announced for 2030, as action over the remainder of this decade will be critical to achieving net zero by 2050. Results and parameters are based on the trends of the NZE Scenario; while we live in a world where oil and gas demand is not falling at the pace seen in the NZE Scenario, the structure and quantitative aspects of the framework remain relevant for assessing the contributions of companies looking to say they are playing their part (Box 3.5).

In this framework, companies that chose to align with net zero transitions are assessed on: their 2030 target for scope 1 and 2 emissions reductions, whether or not they have plans to develop new long lead time conventional oil and gas production, and their 2030 target for the share of investment in clean energy, if they are looking to develop these types of projects (Figure 3.20). This is complemented by qualitative aspects including measurement and transparency, the planned use of offsets, and a company's plans for the stewardship of oil and gas asset disposals.

An oil and gas company is fully aligned with the outcomes of the NZE Scenario only if it no longer plans to invest in new oil and gas projects and if it has a target for its scope 1 and 2 emissions intensity to be aligned with current best practices by 2030 or for these emissions to be cut by 60% by 2030.

However, if a company plans to continue to invest in new projects, it is assessed on its 2030 target to limit scope 1 and 2 emissions and 2030 target for the share of its capital budget going towards clean energy technologies. A target for a share greater than 50% in 2030 would allow the company to claim it is making a fair contribution to the scaling up clean energy necessary to achieve net zero emissions by 2050. The following sections explain these aspects in more detail.

Box 3.5 ▷ What should oil and gas companies do in a world not on track to achieve its climate goals?

Recent progress on clean energy technologies is keeping open the pathway towards limiting the global temperature rise to 1.5 °C, but most technologies are not currently on track with the NZE Scenario and much more needs to be done. A key question becomes what strategies the industry should adopt if oil and gas demand does not decline at the pace seen in the APS or NZE Scenario.

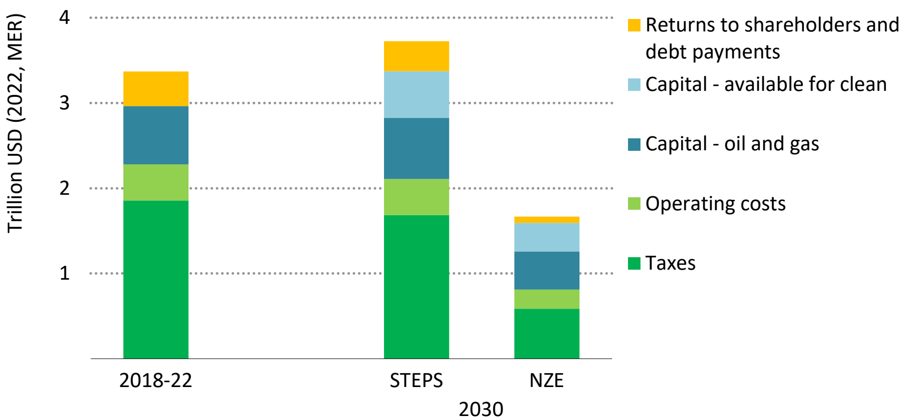
In the Stated Policies Scenario (STEPS), oil and gas demand reach a peak before 2030 but investment in both new and existing fields is required. One option is simply to supply these fuels for as long as they are in demand and returns on investment are sufficient. But forward-looking companies seeking to make the case that they are playing an active role in accelerating the energy transition would need to go much further than this. Indeed, companies continuing with business-as-usual risk losing their "social licence" to operate as the damage from climate change becomes ever more apparent.

Minimising emissions from core oil and gas operations should be a first-order priority for all, in any scenario. Aiming to reduce scope 1 and 2 emissions intensity in line with the reductions in the NZE Scenario would be beneficial whatever the broader transition pathway.

For investment in clean energy, investment strategies would need to find a middle ground between scenario outcomes to hedge against the risk of either overinvestment or underinvestment (as explored in Chapter 1). Importantly, if demand and prices evolve as in the STEPS, the after-tax capital resources available to the industry are higher, even after maintaining a similar level of dividends for shareholders to today (Figure 3.21). Companies could choose to dedicate a larger share of their investment to clean energy, and work with governments and consumers to ensure that markets and infrastructure develop quickly for low-emissions goods and services.

In 2030 in the NZE Scenario, the oil and gas industry invests around USD 350 billion in oil and gas and, if taxes are reduced as a share of revenue from current levels and shareholders accept lower payouts, around USD 350 billion capital would be available to invest in clean energy (i.e. a clean energy investment share of 50%). In 2030 in the STEPS, oil and gas investment is higher at USD 700 billion and, if taxes and payouts to shareholders remain around historic levels, the capital available to invest in clean energy would be USD 500 billion (i.e. a share of 40%). In other words, for forward-looking companies, looking to invest close to 50% of capital expenditure in 2030 in clean energy would be plausible even in a scenario that does not align with global climate targets.

Figure 3.21 ▷ Indicative distribution of annual oil and gas industry revenue in the STEPS and NZE Scenario



In the STEPS, oil and gas companies have more resources to commit to clean energy and investment in scope 1 and 2 emissions reductions.

3.6.2 Scope 1 and 2 emissions reductions

Global scope 1 and 2 emissions fall from 5.1 Gt CO_2-eq in 2022 to less than 2 Gt CO_2-eq in 2030 in the NZE Scenario (Chapter 2). This 60% reduction is achieved mainly through a 50% reduction in the global average emissions intensity of oil and gas operations. Forward-looking companies are likely to need to move faster than this – and building a broader coalition of companies willing to play their part is a crucial step forward – but the global average rate of reduction sets a baseline for the overall changes that would be consistent with the NZE Scenario. This reduction is achieved across the entire oil and gas supply chain and the overall reduction includes emissions from both operated and non-operated assets. Targets looking to achieve less than a 60% reduction by 2030 are placed along the horizontal axis of the framework moving from right to left.

An additional 60% reduction in scope 1 and 2 emissions from 2022 levels could be challenging for companies that have already undertaken major emissions reduction efforts in the past (Section 3.5.1). In this case – which can only be demonstrated with reliable measurements and transparent reporting of all emissions from the production, processing and transport of oil and gas owned – a 2030 target to achieve the emissions intensity of the best practices seen today could be used, as this would broadly align with the outcomes of the NZE Scenario.

In our framework, 2030 targets to achieve best practices across the supply chain are set at 100% and the average values achieved by the industry today set at 0% (Table 3.1). For companies involved in multiple parts of the oil and gas supply chain, a single number can be derived by taking the degree of alignment for each individual segment of the supply chain and then weighting each by the share of the company's overall emissions that come from that segment. For example, if a company has 2030 targets to achieve an emissions intensity of 10 kg CO_2-eq/boe in upstream gas operations and 15 kg CO_2-eq/boe in LNG liquefaction, it would be 94% aligned on upstream and 61% on LNG. If three-quarters of its total emissions come from upstream gas and one-quarter from LNG, its combined metric would be 86%.

3.6.3 Investment in new oil and gas projects

In the NZE Scenario, the overall trajectory of falling demand can be met without any approval of new long lead time upstream conventional projects. Companies aligned with the results of the NZE Scenario would not invest in new exploration or approve new projects. One possible caveat to this result is if a company were to choose to develop a new project and to close another project of a similar size and production profile within its own portfolio. While field abandonment and replacement has been common practice for the industry, the trajectory of steeply declining demand in the NZE Scenario would impose a very different set of conditions than in the past, and no companies have to date proposed adopting this approach to alignment with the NZE Scenario.

Another important – but often overlooked – nuance to the result from the NZE Scenario on new upstream oil and gas projects is that the IEA publishes a full update to all scenarios every year. This means that the oil and gas projects incorporated in successive editions of the NZE Scenario change in each update. For example, in the first version of the NZE Scenario published in 2021, supply projections included projects that had already been approved or were expected to be approved by the end of 2021. A similar approach was taken in the updated NZE Scenario in the *World Energy Outlook 2022*, with the cut-off point at the end of 2022; the latest update to the NZE Scenario as described in this report now includes projects expected to be approved by the end of 2023.

Updates to the NZE Scenario are essential to ensure that it is grounded in real-world conditions, but this implies a moving target for the projects compatible with the goals of the scenario. In this year's edition of the NZE Scenario, oil and gas projects approved in 2023 are included and the pace of reduction in oil and gas demand in the 2030s and 2040s now means that some production will need to be closed before fields have reached the end of their technical lifetime. For this reason, the framework specifies that no investment in any new long lead time upstream oil and gas projects is required from today to align with the outcomes of the NZE Scenario.

3.6.4 Investment in clean energy

A decision to invest in new oil and gas fields does not rule out the possibility that companies could look to play their part in scaling up clean energy deployment. As described in Section 3.5.2, it is challenging to derive a single number for the share of clean energy investment that would be consistent with the overall trends in the NZE Scenario. Investing 75% of the available capital in clean energy in 2030 is theoretically possible, but this would imply that all governments and shareholders around the world accept no tax revenues or direct returns from oil and gas sales. Conversely, if there is no change in government tax takes or shareholder returns, there would be no capital left available after all necessary oil and gas spending. We estimate that if governments, companies, shareholders and financial actors work together, a 50% share by 2030 would be feasible.

This share is the total spending on all clean energy technologies by the company divided by its total capital expenditure. Both figures exclude investment in scope 1 and 2 emissions reductions, since efforts to reduce scope 1 and 2 emissions are included in the framework on the horizontal axis. Also excluded in the numerator is investment in emissions credits generated from outside the energy sector, including nature-based solutions, since these are not included within the scope of the NZE Scenario.

3.6.5 Qualitative qualifiers

In addition to these quantitative aspects, there are additional considerations that provide insights into how companies are aiming to achieve their goals and the ease with which their targets can be assessed.

Measurement and transparency: Uncertainty about current scope 1 and 2 emissions levels is high and reducing this through direct measurement is critical to measure progress against targets. Transparency of disclosures is invaluable for policy makers, financial actors and companies to allow for comparability and build public confidence. This should include how targets will be achieved, what elements are included within scope 1 and 2 emissions targets, and what is considered within clean energy spending goals.

Emission offsets: Offsets from outside the energy sector are not included in the NZE Scenario and they are not included in the scope 1 and 2 emissions reductions or clean energy investment in the framework. In the NZE Scenario, negative emissions are generated from within the energy sector and some of these offset residual emissions from oil and gas operations (Box 3.1). This occurs only after emissions reduction measures have been deployed to the fullest extent possible, with the majority of residual emissions from oil and gas operations stemming from transport. Plans to use a high level of offsets to achieve scope 1 and 2 emissions reduction targets may indicate the company does not aim to actively pursue the real emissions reductions that are necessary. Transparency about the magnitude of offsets being used, how these offsets have been generated, and the nature of emissions that these are offsetting, is therefore critical.

Oil and gas asset disposals: Mergers and acquisitions are a natural part of the oil and gas industry. Asset sales may help a company achieve its own emissions reduction targets, but they could lead to an increase in overall emissions if sold to a company with lower environmental targets. Governments must play a central role here to prevent these perverse outcomes, but companies themselves can introduce stewardship policies to ensure that their emissions reduction targets fully contribute to global net zero transitions.

Strategic responses of exporters and importers

SUMMARY

- Change is unavoidable for producer economies in net zero transitions. Transitions increase the likelihood of boom and bust cycles for oil and gas producers and – with oil and gas markets entering terminal decline – the baseline expectation should be for a bumpy ride. Strategies will necessarily vary from country to country, but a common element is that while net zero transitions will present immense challenges for producer economies, their energy advantages do not disappear overnight.
- Ten established producer economies in the Middle East, Africa and Latin America, currently produce more than 30 mb/d of oil and nearly 800 bcm of natural gas annually. Per-capita income from oil and gas sales in the NZE Scenario in these economies falls by 70% to 2030 and by 90% to 2050 compared with the average level between 2010 and 2022. This could create a powerful incentive to accelerate the pace of reform while also draining a source of revenue that could finance it.
- A number of new potential producer economies – Guyana, Mozambique, Senegal and Tanzania – have seen large oil and gas discoveries in recent years. Despite growing domestic consumption, the prospects for new projects hinge mainly on exports, and their economics are very sensitive to the pace of global energy transitions. In the APS and NZE Scenario, new large-scale oil and gas projects would face major commercial risks and they may struggle to generate any real income. None of these countries have universal access to energy today, but it is achieved in full by 2030 in the NZE Scenario; this would require less than USD 2 billion annual investment to 2030.
- We explore elements of energy strategies for producer economies that, depending on their context, could complement broader reforms to build macroeconomic stability. These include: reducing the emissions intensity of oil and gas operations; securing additional value from traditional supplies by reducing flaring and methane emissions and increasing non-combustion uses of oil and gas; phasing out inefficient fossil fuel subsidies; boosting clean energy deployment to reduce domestic oil and gas use; stepping up low-emissions fuel production; and expanding into new clean energy supply chains.
- Net zero transitions can only occur smoothly if producer and consumer countries provide clear signals on their direction of travel, work together in a mutually beneficial manner, and implement coherent cross-border measures. We examine four routes for effective international co-operation: sending the right market signals; working together to unlock investment in low-emissions fuel trade; collaboration on technology; and bilateral and multilateral engagement. There are several examples of current policy efforts that promote action in these areas.

4.1 Introduction

Economies that are heavily reliant on oil and gas revenues face some stark choices in energy transitions. These choices are not new: the benefits of a shift towards a more diversified economic structure and sustainable energy mix have long been recognised, not least by the producer economies themselves. But net zero transitions introduce an additional element of urgency, as they add a timeline and a deadline. If governments around the world meet their announced pledges or mobilise to limit global warming to 1.5 °C, this will have profound impacts on oil and gas income in the coming decades. It creates powerful incentives to accelerate the pace of reform, while also draining a source of revenue that could finance it.

As we wrote in an earlier landmark report on this issue in 2018, "fundamental changes to the development model in resource-rich countries look unavoidable" (IEA, 2018). In this chapter, we explore what this complex process might look like. We start by analysing the current situation in different economies with large oil and gas resources, including established producers and countries looking to step up their development. We consider the implications of net zero transitions for production prospects and revenues, as well as different energy-related diversification options and strategies. Finally, we assess the ways that international partners can support the diversification process, and the collaborative ways in which today's oil and gas exporters and importers can work together to help net zero transitions globally.

As in 2018, we conclude that the need for change is unavoidable and that the development prospects for any country that fails to recognise this are bleak. At the same time, we urge a considered approach: each country needs a well-designed strategy for what comes next based on a clear-headed assessment of its strengths and weaknesses. These strategies will necessarily vary from country to country, and many will require external technical and financial assistance. A common element, however, is that the energy advantages of today's producer economies do not disappear overnight. These countries are competitive providers of traditional fuels; many also have high potential to produce low-emissions fuels and power, and to create new industries and employment opportunities on that basis.

The producer economies considered in this chapter are divided into two main groupings: established producers and new producers.

The first group of **established producers** comprises ten countries: Algeria, Angola, Iran, Iraq, Nigeria, Oman, Qatar, Saudi Arabia, United Arab Emirates and Venezuela. These are not necessarily the most vulnerable countries in energy transitions, but they represent a cross-section of producers that are heavily dependent on hydrocarbon revenues and they illustrate a range of starting points and circumstances. Russia is the main producer economy not included in this analysis; many of the considerations discussed here also apply to Russia, but the country's role in international energy is in flux in light of its invasion of Ukraine.

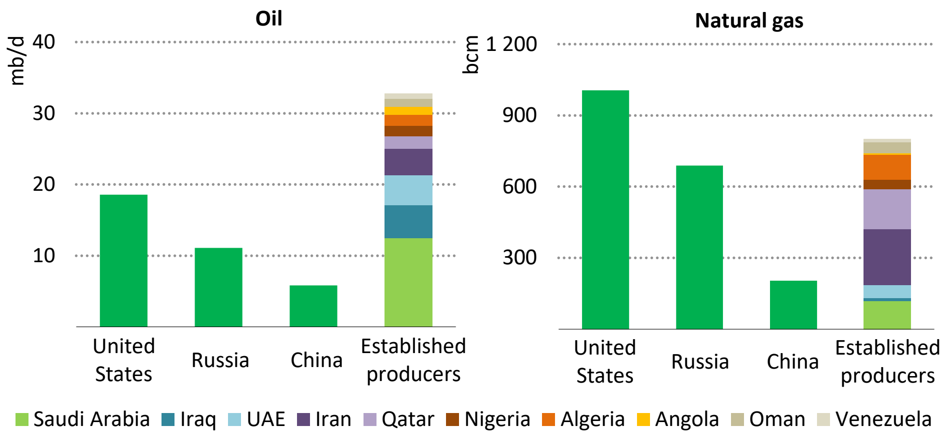
The second grouping of **new producers** comprises four countries that have recently seen substantial oil and gas discoveries and are looking to scale up production: Guyana, Mozambique, Senegal and Tanzania.

4.2 Established producers

4.2.1 Starting points

The established producers examined in our analysis play a central role in oil and gas markets. In 2022 these countries produced more than 30 million barrels per day (mb/d) of oil – more than one-third of global oil production – and 800 billion cubic metres (bcm) of natural gas, which is around 20% of global production (Figure 4.1). They are responsible for 45% of global oil exports and 30% of global liquefied natural gas (LNG) exports.

Figure 4.1 ▹ Role of selected producer economies in global oil and gas production, 2022



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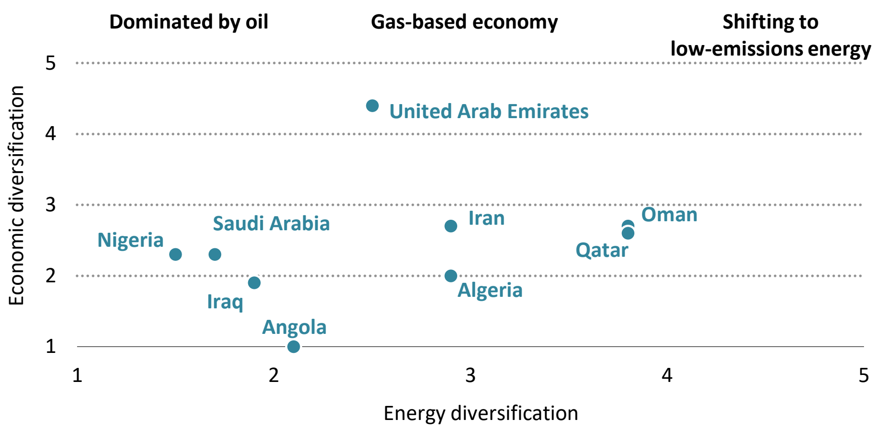
The established producers examined in this report produce more than one-third of global oil production and around 20% of global natural gas production.

Note: mb/d = million barrels per day; bcm = billion cubic metres per year; UAE = United Arab Emirates.

These countries are very diverse and over the years have managed their resources and economic policies in different ways. But they all depend on oil and gas sales for a substantial part of their national budgets. We have assessed the starting points of the countries in this grouping across two dimensions of diversification: economic and energy. The economic diversification indicator looks at the role of sectors other than oil and gas in the economy, while the energy indicator assesses the role of non-hydrocarbon resources in the overall energy mix. Our analysis highlights that most of these producers are only at the beginning of their journeys, but also that substantial differences between them already exist (Figure 4.2).

The United Arab Emirates scores relatively well on both dimensions, having increased substantially the share of non-oil and gas exports in recent years. The role of solar and nuclear power (the latter since 2020) is also increasing in the UAE power mix. Other producers have made less progress than the United Arab Emirates on the economic front, although Algeria and Oman have seen a number of improvements. Some have moved further with energy diversification, led by Oman and Qatar. The least diversified among our selected producer economies are Iraq and Angola; these countries face the greatest challenges from high dependence on oil and are most vulnerable to the effects of revenue volatility. The strains facing these countries during transitions are exacerbated by their exposure to a range of climate-related risks (Box 4.1).

Figure 4.2 ▻ Selected producer economies by degree of economic and energy diversification



Each established producer economy has distinctive national circumstances and track record; none of them are currently visibly shifting towards a low-carbon energy system.

Notes: Economic diversification score is the average of the share of non-oil and gas exports in total exports in 2021 (with a weighting of 70%) and the growth of non-oil and gas export revenue since 2010 (with a 30% weighting). Energy diversification score is calculated as the weighted average of the share of oil, coal and traditional use of biomass in 2021 and changes since 2010 (50% and 20%, respectively) and the share of renewables and nuclear in 2021 (30%).

Source: IEA analysis based on export data from IMF (2023a).

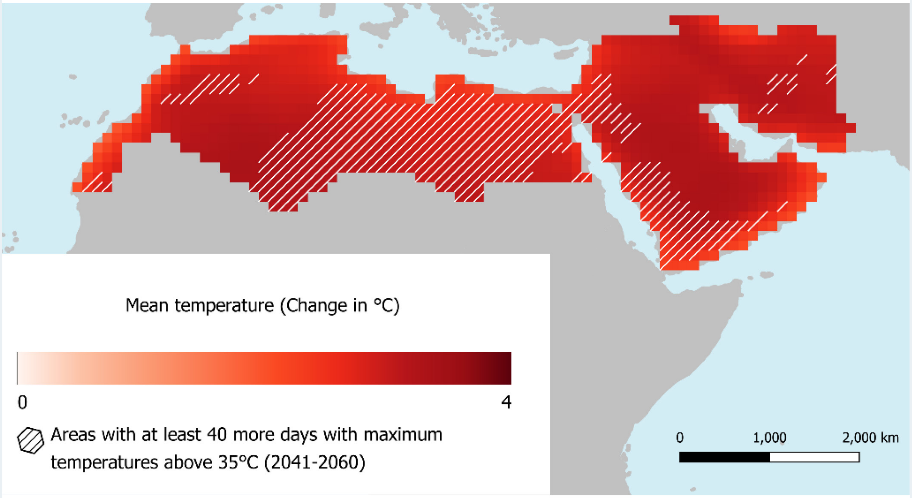
Box 4.1 ▻ Climate vulnerabilities are hitting producer economies

Many of the world's major oil and gas producers are also in parts of the world that are strongly affected by a changing climate. Between 1980 and 2020 the global average temperature increased by close to 0.2 °C per decade, while temperatures in most of the established producers – particularly those in the Middle East and North Africa – increased by more than double this. This has been accompanied by more frequent extreme weather events, such as heatwaves and droughts.

The global average temperature today is around 1.2 °C higher than pre-industrial levels; in the States Policies Scenario (STEPS), this increases to around 1.9 °C in 2050 and to

2.4 °C in 2100 (Figure 4.3). This would translate into an even greater number of extreme weather events. For example, in the Middle East, the number of hot days with a maximum temperature above 35 °C would increase from 121 on average each year during 1995-2014, to 143 around 2050, and to 155 by 2100.[1]

Figure 4.3 ⊳ Temperature changes in the Middle East and North Africa in the Stated Policies Scenario, 2041-2060



Climate hazards such as extreme heat pose major dangers to people and development, and need to be incorporated into transition planning.

Notes: Map presents the impacts of SSP2-4.5, which is broadly consistent with the temperature outcomes of the STEPS.

Sources: IEA analysis based on IPCC (2021).

In July 2022 temperatures in Baghdad reached almost 52 °C, the hottest day that Iraq has ever recorded, and Iraq provides a telling example of the negative effects of climate change on development. Climate change is exacerbating existing problems with water scarcity and, without intervention, the gap between water supply and demand could rise to more than 15% of total water demand by 2035 (World Bank, 2022). This would have wide-ranging impacts on crop yields and food prices, disproportionately affecting the poorest and most vulnerable sections of the population. The agricultural sector employs almost 10% of Iraq's working population, and workers in other sectors such as construction would also be affected by exposure to extreme heat.

[1] Climate impacts here are based on results from the SSP2-4.5 scenario assessed by the Intergovernmental Panel on Climate Change (IPCC) that is it is broadly consistent with the temperature outcomes of the STEPS.

Higher average temperatures also have wide-ranging negative consequences for the energy sector, creating peaks in cooling demand that can be difficult to manage. Rising temperatures worsen the operational performance of electricity grids and make it more difficult to cool thermal power plants. They can also pose challenges to oil and gas infrastructure through increased aridity and droughts. In Iraq, water injection is widely used to increase recovery from the country's large southern fields, and a lack of water could stymie production.

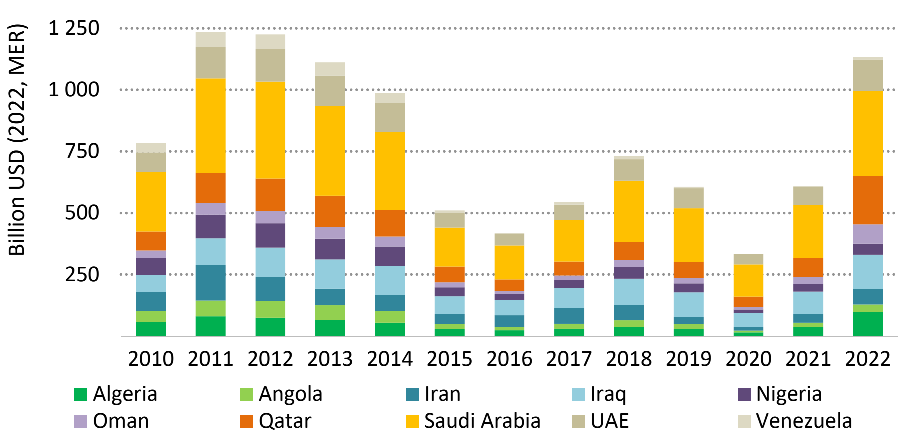
4.2.2 Pitfalls facing producer economies

Three areas have traditionally been challenging for countries that derive large revenues from oil and gas: revenue volatility; job creation and productivity; and energy pricing and efficiency.

Revenue volatility

Producer economies are heavily dependent on revenues from oil and gas exports to fuel economic growth and to support public spending; their fiscal balances are therefore vulnerable to changes in oil and gas prices. For example, the last ten years saw a period of bounty in the early 2010s, a sharp drop in income mid-decade, the shock of the Covid-19 pandemic on commodity prices and production levels in 2020, followed by a sharp rebound in 2022 (Figure 4.4).

Figure 4.4 ▷ Net oil and natural gas income in the ten established producer economies, 2010-2022



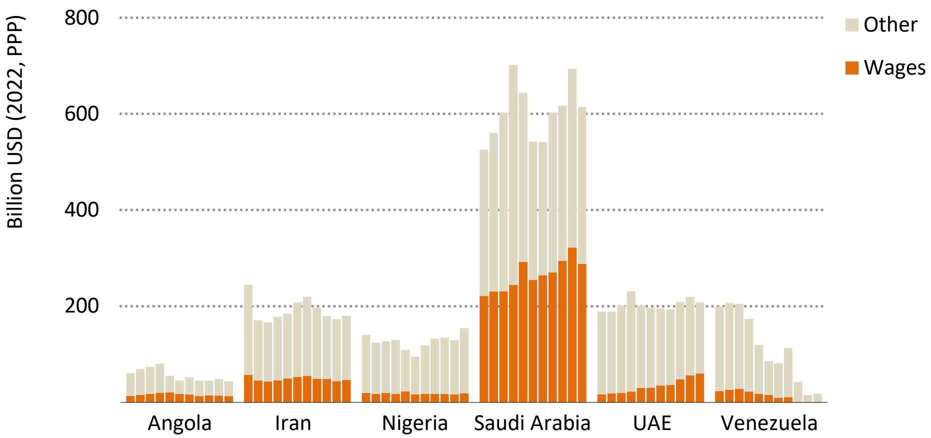
The ten producer economies have seen huge swings in income from oil and gas sales.

Note: UAE = United Arab Emirates.

The well-documented risk is that patterns of government spending – and reinvestment in oil and gas projects – mirror these revenue cycles, such that an expansion in spending during boom times is then followed by painful cutbacks when prices fall (Figure 4.5). This can have destabilising effects on the economy and welfare, especially if the government employs a large share of the workforce. Without mitigating actions, year-on-year swings in spending force difficult decisions about which services or jobs to cut, making it hard for citizens to invest and plan for better livelihoods.

Although challenging to implement in practice, there are tried and tested ways to mitigate the impacts of oil price volatility on spending and growth. A key aim is to try to introduce counter-cyclical fiscal policies, whereby governments trim spending and raise additional revenues during the years in which commodity prices are high, to give them the option of increasing spending and reducing taxes to stimulate growth during leaner years. This objective can also be helped by implementing multi-year spending plans, setting limits on annual spending increases, or specifying that (as Russia did in previous years) any excess revenues above a specified oil price be diverted into a savings fund.

Figure 4.5 ▷ Public expenditure on wages and other services in selected established producer economies, 2011-2021



Dependence on oil revenue can increase the volatility of public spending, forcing difficult year-on-year decisions on cutting jobs, cutting other services or using foreign reserves.

Notes: PPP = purchasing power parity; UAE = United Arab Emirates.

Source: IEA analysis based on World Bank (2023a).

The development of sovereign wealth funds can provide a buffer against oil price volatility. Revenues from investments in diversified portfolios that include strategic assets, stocks and other securities have allowed some producer economies to support their welfare systems and invest in ambitious diversification programmes. For example, Saudi Arabia's

USD 620 billion Public Investment Fund underpins the country's Vision 2030 plan, which aims to limit the country's reliance on oil and gas revenues (among other objectives). In the United Arab Emirates, the USD 800 billion Abu Dhabi Investment Authority and investment company Mubadala conduct strategic investments in a range of sectors, including energy, through subsidiary companies such as Masdar.

Some producer economies used the increases in income in 2021 and 2022 to strengthen domestic and overseas investments. For example, Oman, Qatar and Saudi Arabia are boosting efforts to diversify their economies, including investment in clean energy, technology and healthcare, as a means to develop new domestic industries as well as generate a return on investment. Others, including Algeria and Venezuela, have more limited tools to manage the impacts of price volatility, including lower administrative capacity to collect and redistribute fiscal income.

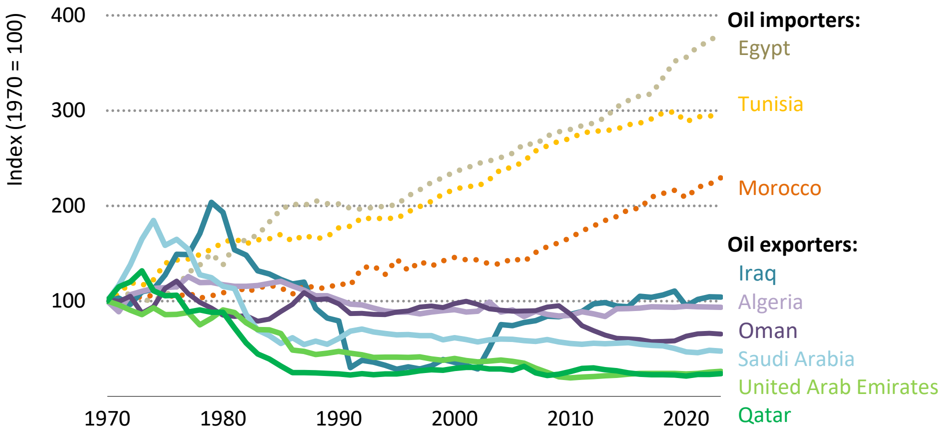
Another mechanism to protect against price volatility is to build up foreign reserves during times of high commodity prices to lessen decreases in government spending during periods of low oil and gas prices. A mixed picture emerges among the producer economies in 2021 and 2022: Algeria and Iraq increased reserves, while Angola and Nigeria saw a decrease as they struggled to maintain production and faced increased calls on government expenditure for food and fuel subsidies following Russia's invasion of Ukraine. International sanctions on some of the producer economies also mean they are unable to access and use foreign currency reserves.

Job creation and productivity

The population of our established producer grouping has grown at a faster rate than the global average since 1990. People under the age of 30 now account for more than half of the total population, compared with around one-third in advanced economies. A young working population can be a spur to growth, but if countries are unable to create productive opportunities at scale, it could also be a major source of strain. Demographic pressures are lower in producers such as Qatar and the United Arab Emirates – although both are heavily dependent on expatriate labour – but are a huge issue in other countries, notably Saudi Arabia, Iraq and Nigeria.

The temptation for governments, particularly when oil prices and revenues are high, is to absorb these strains via an increase in public sector employment. It is difficult to estimate the share of public sector employment in several of our established producer grouping due to data scarcity and the size of the informal economy. Nevertheless, more than half of the citizens in Saudi Arabia registered in the social security system are employed in the public sector and wages represent around half of public expenditure. This stems mainly from the higher pay and benefits offered by public sector jobs, which has limited the private sector's access to the talent needed to support its development (Hani & Lopesciolo, 2021). This has led to major distortions in the labour market, with private sector job creation not keeping up with increases in the availability of new workers. As a result, labour productivity in many producer economies has not kept pace with that of their neighbours (Figure 4.6).

Figure 4.6 ▹ Labour productivity in selected countries in the Middle East and North Africa



Oil and gas exporters have seen a relative drop in labour productivity, while non-exporting countries in North Africa have seen an improvement.

Source: The Conference Board (2023).

Creating a dynamic private sector is a broad public policy challenge, but a vital one if producer economies are to pursue a resilient, inclusive and diversified growth path. This is central to the reform plans of most producer economies. The United Arab Emirates has successfully developed itself as a major financial, logistics and services hub, and has reduced the share of fuel exports in total exports from 95% in 2000 to around 50% in 2022. Saudi Arabia has made a number of advances in recent years and its Vision 2030 includes the ambition for the private sector to account for 65% of gross domestic product (GDP) by the end of this decade, from close to 40% today.

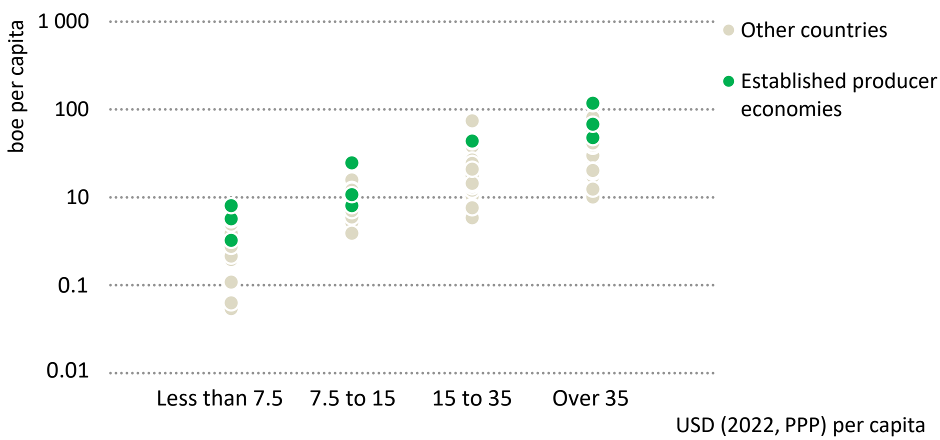
Several producer economies have also leveraged their status as major producers to create local supply chains. For example, since 2015 Saudi Aramco has been looking to source an increasing share of its procurement domestically as part of the In-Kingdom Total Value Add programme. As of 2022, 63% of Saudi Aramco's spending was directed to domestic suppliers, up from 35% in 2015, and it has a target to reach 75% by 2025.

Increasing the dynamism of the private sector in the broader economy will depend on efforts to improve government effectiveness, regulatory oversight and the rule of law. Low scores in these areas are not typically a major impediment to the development of the oil and gas sectors – most producer economies have a higher level of economic output than countries with comparable levels of governance – but they are crucial to cultivate a broader basis for economic growth. Despite recent efforts to diversify revenue and strengthen the role of the domestic private sector through governance reforms, significant challenges remain.

Energy pricing and efficiency

The types of businesses that thrive in any given economy depend on many different factors, and energy is a crucial one. Ample availability of competitively priced fuels and electricity is an important consideration for many industrial sectors. However, if this advantage is derived from policies that hold prices well below their market value, this can distort investment incentives for businesses and households alike and lead to widespread inefficiencies. Some of the producer economies examined in this chapter are the most energy-intensive countries in the world, and in some instances this indicator is heading in the wrong direction (Figure 4.7). Their average energy intensity – measured as energy demand per unit of GDP – increased by nearly 10% between 2010 and 2021, a period when the global average fell by more than 25%.

Figure 4.7 ▷ Total energy demand and GDP per capita in 2021

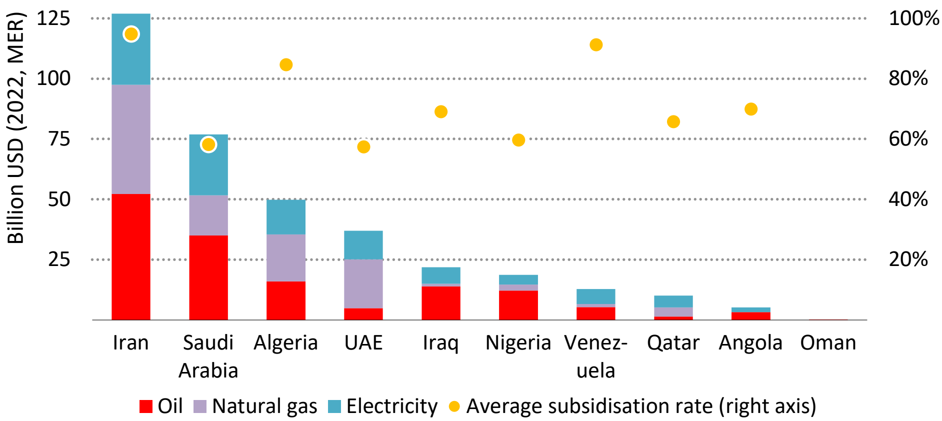


Producer economies tend to be the highest energy users among countries with similar levels of GDP per capita.

High energy intensity in itself is not necessarily a warning sign; it could simply be a reflection of comparative advantage. But in practice, subsidies also play a major contributing role, both directly for fuels and also for electricity. In 2022 the ten established producer economies in our grouping accounted for around one-third of worldwide fossil fuel consumption subsidies. The total value of these subsidies in 2022 in these economies was around USD 360 billion. Iran's fossil fuel subsidies are the largest in the world, with an estimated value of over USD 125 billion (equivalent to 35% of the country's GDP) (Figure 4.8).

Many producer economies have introduced periodic energy pricing reforms to reduce the level of subsidies. Despite these efforts, overall subsidy levels have followed closely the trend for oil and gas prices, and indeed the increase in recent years has exceeded the movement in price levels (Figure 4.9).

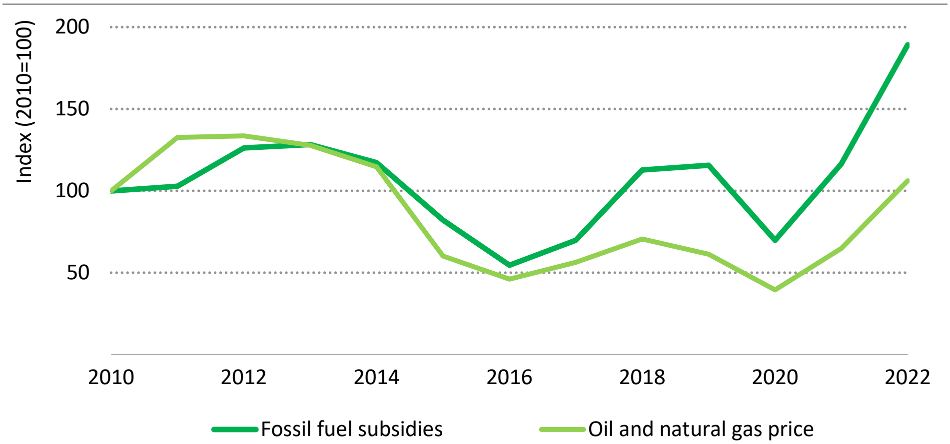
Figure 4.8 ▷ Fossil fuel subsidies in established producer economies, 2022



Fossil fuel consumption subsidies are prevalent in many producer economies and account for one-third of global fossil fuel subsidies.

Notes: UAE = United Arab Emirates. The average subsidisation rate is the combined ratio of subsidies for oil and gas and electricity produced from fossil fuels to international reference prices.

Figure 4.9 ▷ Evolution of oil and natural gas prices and fossil fuel subsidies in the established producer economies



Despite efforts by some producer economies to revise fossil fuel subsidies, there has been no decoupling between prices and subsidy levels since 2010.

Note: Oil and gas price is the combination of international reference prices for oil and natural gas for the producer economies weighted by domestic oil and gas consumption.

In the exceptional circumstances of 2022, governments found multiple ways to avoid passing on high and volatile prices to consumers. In some instances, these measures involved direct allocations from national budgets; in other cases, subsidy estimates reflect income that was foregone by producer economies in keeping domestic prices much lower than international benchmarks.

As well as encouraging inefficient energy use, fossil fuel subsidies also tilt the scales against the deployment of clean energy. Producer economies in the Middle East have some of the best solar irradiation rates in the world and the potential to develop some of the lowest-cost solar projects. The United Arab Emirates and Saudi Arabia have seen solar photovoltaic (PV) prices below USD 15 per megawatt hour owing to high capacity factors, beneficial financing and land costs, and large project size, which allow for the cost advantages of economies of scale. New projects are under development, but as of 2022 only 8 gigawatts (GW) of solar capacity was installed in the Middle East (for comparison, the Netherlands had around 20 GW) and solar provided only 1.5% of electricity generation in the region in 2022.

4.2.3 Impacts of net zero transitions

Net zero transitions will have profound implications for development models based on hydrocarbons. Our scenarios provide a sense of the magnitude of the changes for oil and gas producers as demand falls back and prices ease. As major resource-holders, many of the producer economies are also among the world's least-cost suppliers and so retain strong footholds in the markets – at least during the initial years of our projections. But the trajectories mapped out in our scenarios may in some ways understate the difficulties that lie ahead, in that the lines to 2050 are relatively smooth and, as such, provide a hint of certainty and predictability for the producers. No such assurances can be provided in practice. Even as overall volumes contract, commodity markets are likely to continue to be characterised by regular market imbalances. Transitions arguably increase the likelihood of boom and bust cycles for oil and gas; the baseline expectation should be for a bumpy ride.

The projections nonetheless provide important orientation for the future. In the APS, oil production by our grouping of established producer economies remains broadly flat to 2030 (at just over 30 mb/d) and falls to 23 mb/d in 2050; gas production rises to 900 bcm in 2030 but then peaks and falls back to 2022 levels in 2050 (800 bcm). Net income from oil and gas is not materially different from the average levels seen during 2010-2022 until the latter part of the projection period (Table 4.1).

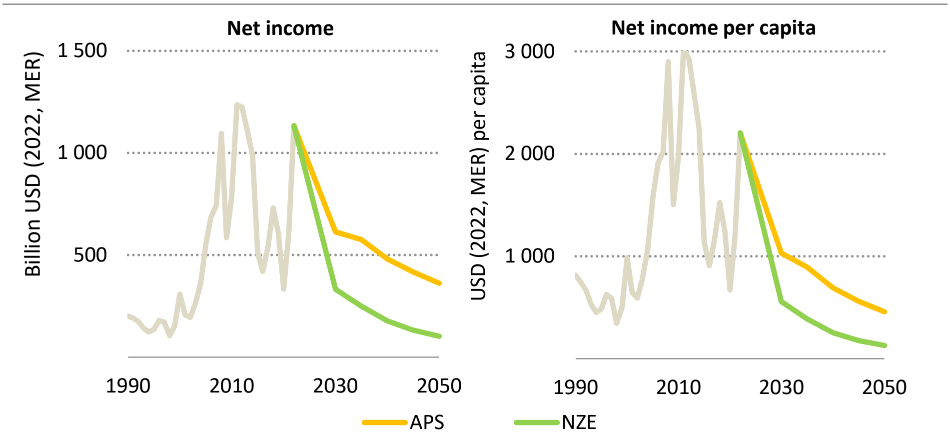
Rapid population growth means that there is a decline in income expressed on a per-capita basis. This is particularly the case for Angola, which doubles its population by 2050, and for Nigeria and Iraq, which both see a 70% increase in population to 2050. Across the established producer economies as a whole, per-capita income in the APS by 2050 is 75% lower than the average level during 2010-2022 (Figure 4.10).

Table 4.1 ⊳ Average annual net income from oil and natural gas for producer economies by scenario (billion USD [2022, MER])

			STEPS		APS		NZE Scenario	
	2010-21	2022	2023-30	2031-50	2023-30	2031-50	2023-30	2031-50
Saudi Arabia	248	347	280	315	253	208	184	89
Qatar	83	195	88	125	80	82	52	27
Iraq	92	139	121	142	104	68	74	24
UAE	86	127	97	118	84	69	55	23
Algeria	44	97	32	13	31	11	21	9
Iran	62	62	41	44	35	14	25	8
Oman	30	78	31	24	28	13	16	3
Nigeria	54	46	20	18	19	7	11	3
Angola	34	31	16	13	15	7	9	2
Venezuela	25	10	12	17	9	7	4	1
Total	758	1133	738	829	657	485	450	189

Note: UAE = United Arab Emirates

Figure 4.10 ⊳ Net income from oil and gas in the established producer economies in the APS and NZE Scenario



In the APS, net income is similar to historical levels but population growth means per-capita income falls sharply. In the NZE Scenario, net income per capita is 60% lower by 2030.

In the NZE Scenario, much lower global demand and lower commodity prices mean that the established producer economies already see significantly lower oil and gas income over the coming decade. Compared with the annual average between 2010 and 2022, net income from oil and natural gas is around 60% lower in 2030 and per-capita net income in 2030 is 70% lower.

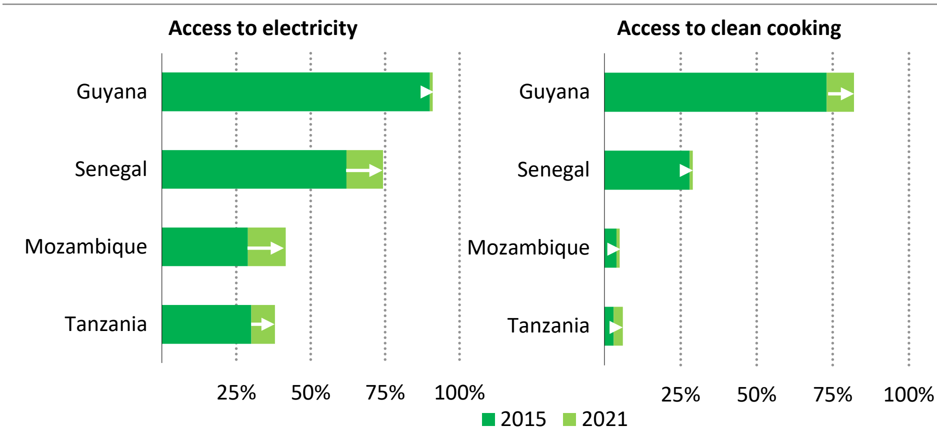
4.3 New producers

4.3.1 Starting points

The new producer economies examined here – Guyana, Mozambique, Senegal and Tanzania – have all seen large oil and gas discoveries in recent years and have announced major plans to develop them in the coming years. Guyana is furthest along this path. Oil was discovered in the offshore Stabroek Block in 2015 – more than 10 billion barrels of recoverable oil resources have been discovered to date – and production started up at the Liza project in 2019. Explorers continue to find new resources in its waters and production is expected to rise substantially from current levels (275 thousand barrels per day [kb/d] in 2022).

Mozambique is an emerging gas producer, based on a number of huge offshore discoveries in the early 2010s. The country produced 5 bcm of natural gas in 2022 and exported around 80% of its production. Supply is set to double in 2023 and then grow further as a number of new LNG plants are being developed. The only existing facility is a floating one (Coral Sul), which exported its first cargo in the second half of 2022. Tanzania, like Mozambique, has seen a number of major offshore gas discoveries, but has to date been less successful in developing major new projects. Senegal currently has very little oil and gas production, but the Greater Tortue Ahmeyim LNG project (shared with Mauritania) is soon expected to start production, as is the Sangomar oil and gas field. These projects are set to move the country from being a net oil and gas importer to an exporter.

Figure 4.11 ▷ Electricity access and clean cooking access in new producer economies, 2015 and 2021



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The new producers have made progress on improving access to electricity and clean cooking, but on current trends they will not all achieve full access by 2030.

A distinctive feature of these new producers is that while all have made progress in expanding access to electricity and clean cooking in recent years, none have yet achieved universal access. Indeed, less than half of people in Mozambique and Tanzania currently have access to electricity and less than 10% have access to clean cooking options (Figure 4.11). Developing new resources in countries with access deficits might seem like an obvious path to follow, but it is not automatic that oil and gas developments provide energy to all. Some well-established producers, notably Nigeria, still have large populations without access. And many countries that have made great strides towards universal access in recent years, such as Côte d'Ivoire, Kenya and Rwanda, have done so without large-scale domestic production.

4.3.2 Impacts of net zero transitions

Oil and gas discoveries may open up the promise of significant future income and resource wealth. But there are significant uncertainties over how they deliver in practice. The well-known "resource curse" describes the ways in which development based on hydrocarbon revenues can actually be detrimental to the economic outlook. They can also lead to corruption and environmental hazards (van Hulst, 2023). Some risks were described in the previous section: the volatility of revenues can be destabilising for public finances and prudent fiscal management; and resource-rich countries can face lower productivity and excessive reliance on public sector employment, as well as inefficient and wasteful use of energy.

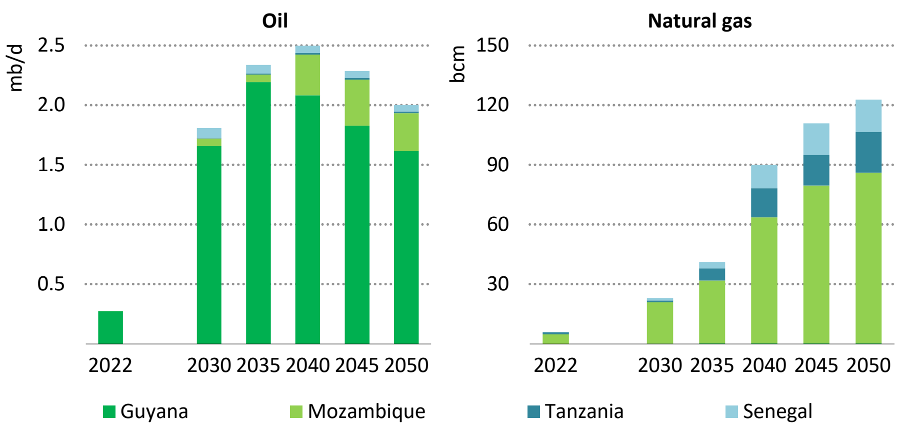
New producers face additional challenges as they are embarking on oil and gas production at a time of heightened uncertainty over future demand. As such, they are prone to the risk of overestimating the bounty that might lie ahead, and underestimating the potential hazards. In some cases, these hazards become visible even before the start of production, as the promise of future revenues encourages higher borrowing and spending. After major discoveries, the International Monetary Fund (IMF) found, on average, that growth has underperformed the post- discovery forecasts (Cust & Mihalyi, 2017). For certain countries, such discoveries have led to significant growth disappointments, even compared with pre-discovery trends. Mozambique's large gas discoveries were made in 2009 at a time when annual GDP growth was around 6%. By 2016, growth had fallen to 3% in large part as a consequence of several huge state-backed "hidden loans".

Declines in global oil and gas demand and lower prices in the APS and NZE Scenario significantly reduce the scope for new oil and gas developments around the world, compared with the STEPS (Box 4.2). Some of the largest impacts are felt by the new producer economies. Cumulative investment in oil and gas to 2050 in Guyana, Mozambique, Senegal and Tanzania is 25% lower in the APS than in the STEPS, and is around 75% lower in the NZE Scenario. In the APS, these countries generate USD 840 billion net income through to 2050 (40% less than in the STEPS) and in the NZE Scenario they generate less than USD 240 billion to 2050 (85% less than in the STEPS) (Figure 4.13).

Box 4.2 ▹ What outlook for new producers under today's policy settings?

Under today's policy settings, as projected in the STEPS, oil and gas production rises substantially in the four new producers examined. Oil production in Guyana rises most significantly to 1.7 mb/d in 2030 (Figure 4.12). Annual natural gas production rises to around 85 bcm in 2050 in Mozambique, 20 bcm in Tanzania and 15 bcm in Senegal. Cumulative investment in oil and gas through to 2050 is USD 420 billion and the countries generate nearly USD 1 400 billion in net income from oil and gas sales.

Figure 4.12 ▹ Oil and gas supply in new producer economies in the STEPS

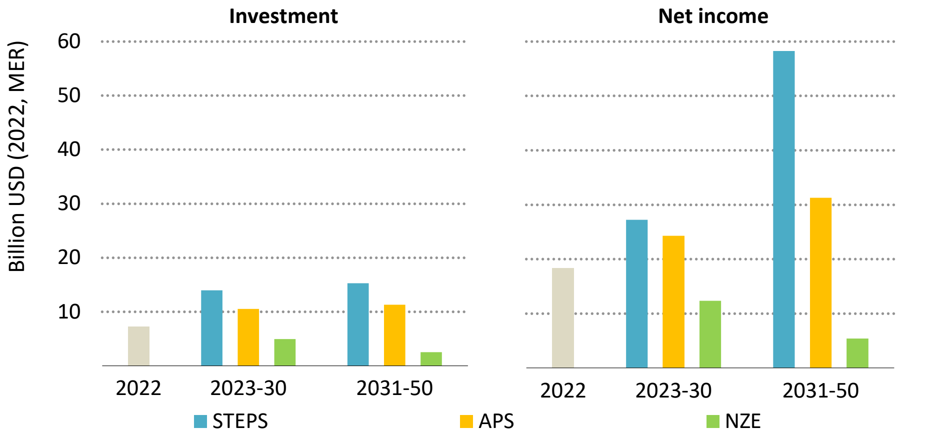


Today's policy settings open substantial market opportunities for new producers of oil and natural gas, but this is not accompanied by the provision of universal access.

There is no guarantee that the income generated by these new oil and gas developments would be directed to achieving sustainable development goals, including universal energy access. Indeed, on the basis of current policy settings, as in the STEPS, between 55-80% of people in Mozambique, Senegal, and Tanzania in 2030 would not have access to clean cooking and nearly half of people in Mozambique and Tanzania would not have access to electricity.

It is understandable why some of the new producer economies are looking to move ahead with the exploration and approval of large supply projects. Africa's oil demand continues to grow until the late 2040s in the APS, and its gas demand until the end of the 2030s, with industrial gas demand continuing to rise through to mid-century. Only in the NZE Scenario does the continent's oil and gas use start to tail off before the end of this decade. However, if the world is successful in targeting and reaching net zero emissions by 2050, any new projects would face major commercial risks. For example, if these countries were to invest in natural gas projects in line with the STEPS but gas prices evolve as in the NZE Scenario, then spending of around USD 240 billion to 2050 (including both capital and operating expenditure) would generate only USD 250 billion in revenue. The projects could even result in losses as gas supply from these countries would be above the levels of the NZE Scenario, potentially leading to even lower gas prices (see Chapter 1).

Figure 4.13 ⊳ Annual average investment and net income from oil and gas in new producer economies by scenario

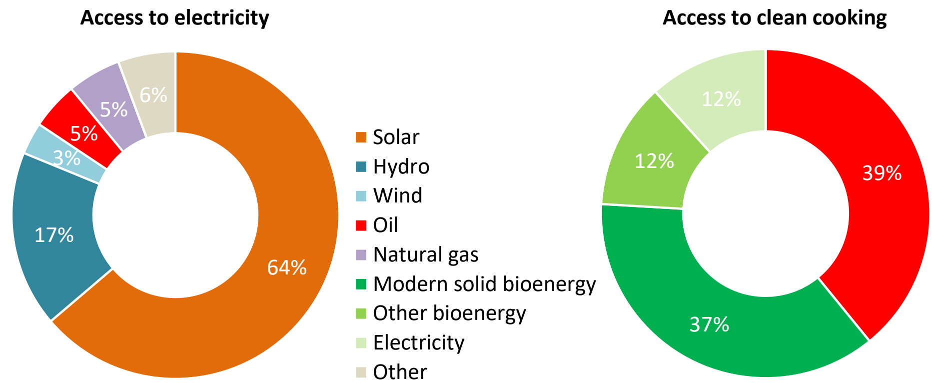


Rapid transitions severely impact the economic viability of new oil and gas investments.

In the case of energy access, the APS and the NZE Scenario both offer improved outcomes compared with STEPS. In the APS, nearly all of the populations of these new producer economies have access to electricity by 2030, although 20% of people would still lack access to clean cooking fuels by the same date. In the NZE Scenario, universal access to electricity and clean cooking is achieved in full by 2030.

Oil and gas do not play much of a direct role in facilitating universal access to electricity in the NZE Scenario in these countries. Across countries in sub-Saharan Africa, renewable technologies provide the energy for 90% of connections to electricity, with solar PV alone providing around two-thirds (Figure 4.14). For clean cooking, around 40% of the people who gain access do so through liquefied petroleum gas (LPG), a further 35% with the use of improved biomass cookstoves, 10% with electricity, and the remainder with solutions such as biodigesters and bio-ethanol. In total, around 25 thousand barrels of oil equivalent per day of oil and gas, mainly for cooking LPG, is used to provide access to energy in Senegal, Mozambique and Tanzania in 2030. Achieving universal access to electricity and clean cooking in these countries requires around USD 2 billion of investment per year to 2030; international support would be vital to mobilise this investment.

Figure 4.14 ▷ Fuels used to achieve universal energy access in countries in sub-Saharan Africa in the NZE Scenario, 2030



In the NZE Scenario 90% of the people gaining access to electricity do so with renewable technologies. Solar PV alone powers around two-thirds of new connections.

4.4 Building resilient net zero energy strategies

The reform process for producer economies is much broader than energy; indeed, the whole point of the process is to reduce the weight of energy in the economy, and to allow other industrial, manufacturing and service sectors to thrive. But a well-functioning energy sector remains vital to the overall chances of success, and it is a mistake to think that the advantages of today's producer economies in the energy sector disappear as the world moves away from fossil fuels. Utilising these opportunities and advantages is not simple and will require new types of collaboration both within countries and internationally. But there are workable net zero energy strategies available to today's producer economies.

One crucial element of the broader context is macroeconomic stability and, as described earlier, this is closely linked to the volatility of energy revenues. A strong anti-cyclical fiscal policy is key to allowing producer economies to ride the unpredictable waves of commodity price fluctuations. Recent analysis by the IMF of oil exporters in Africa showed that most exporters were ill-prepared to cope with oil price changes: accumulated savings were slight, with sovereign wealth funds in sub-Saharan Africa holding assets of just 1.8% of GDP – compared with 72% in the Middle East and North Africa – forcing countries to take on higher debts or draw down financial assets when oil prices fall (IMF, 2022). As a result, in the decade to 2020 the region's oil producers grew over 2 percentage points slower per year than non-resource-intensive countries. The IMF recommended a much larger buffer – of around 5-10% of GDP – in order to manage revenue volatility and create the foundations for more sustainable growth. This imperative only becomes more important as the world moves through energy transitions.

Our energy-related guidance is complementary to these considerations of macroeconomic stability, and falls into three main areas:

Reduce emissions from traditional supplies

- Bring down the emissions intensity of oil and gas production.
- Gain more value by cutting waste and stepping up non-combustion uses.

Put domestic energy systems on a cleaner footing

- Phase out inefficient fossil fuel subsidies.
- Boost efficient clean energy deployment to reduce domestic oil and gas use.

Develop new low-emissions products and value chains

- Step up production of low-emissions fuels.
- Expand into new clean energy supply chains.

4.4.1 Reduce emissions from traditional supplies

Bring down the emissions intensity of oil and gas production

As described in detail in Chapter 2, there is huge scope to reduce emissions from traditional oil and gas operations. Many producer economies are naturally well-positioned to produce oil and gas with low emissions intensities, but in many cases greater effort is needed to bring down energy use and emissions in different parts of the upstream and midstream.

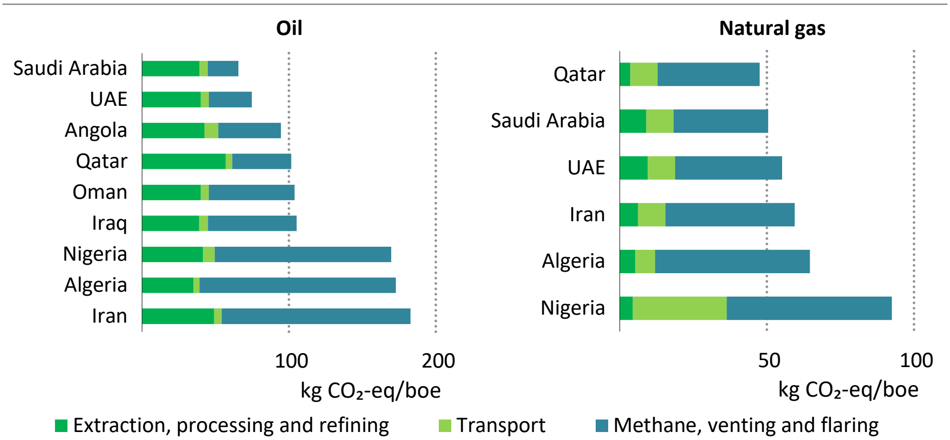
Most of the producers that we examine in this chapter have large subsurface reservoirs with high levels of natural drive pressure. This means that the energy required to extract the oil from the ground is relatively small, especially compared with many mature oil provinces in other parts of the world. The producer economies should therefore have relatively low emissions intensities for oil and gas production; indeed, according to our estimates, Saudi Arabia and the United Arab Emirates have some of the lowest scope 1 and 2 intensities anywhere in the world today. But others, including Algeria and Venezuela, have amongst the highest (Figure 4.15).

For Venezuela, part of this is because its extra-heavy oil requires large quantities of heat and energy to extract, but it is more a function of above-ground issues of methane and flaring. Algeria, for example, flares around 40 times more natural gas than Saudi Arabia for every barrel of oil it produces (see next section). For most of the producer economies, measures targeting methane emissions would have the most immediate impacts to reduce their emissions intensities. Norway provides an important benchmark for performance and best practices (Box 4.3).

Achieving a low emissions intensity is an important strategy for producer economies. It frees up oil and gas for domestic use or export that is currently use to power operations or that is wasted through flaring and venting. Reducing scope 1 and 2 emissions from oil and gas operations is also one of the cheapest options to reduce GHG emissions generally and so would be an effective way for countries to achieve their own domestic emission reduction targets.

In addition, a number of importing countries are also starting to differentiate the emissions intensity of oil and gas imports, and they may look to penalise or restrict imports that have a high emissions intensity (see Section 4.5). This could shut off certain export markets unless producers can reliably demonstrate that they are achieving a low emissions intensity. The need for new oil and gas developments differs according to the pace of the scale-up in clean energy technologies, but producers that can demonstrate strong and effective action to reduce emissions can credibly argue that their oil and gas resources should be preferred over higher-emissions options.

Figure 4.15 ▷ Emissions intensities of oil and gas production in selected producer economies, 2022



A very wide spread in emissions intensities exists between the best and worst performing producer economies.

Notes: kg CO_2-eq/boe = kilogramme of carbon dioxide equivalent per barrel of oil equivalent. One tonne of methane is considered to be equivalent to 30 tonnes of CO_2 based on the 100-year global warming potential (IPCC, 2021). Shows producer economies that produce more than 1 mb/d or 20 bcm of gas.

Producers could go one step further by using carbon removal technologies, such as direct air capture or bioenergy with carbon capture and storage, to remove an amount of CO_2 from the atmosphere similar to the full life cycle emissions of the oil and natural gas (including emissions from combustion). Such emissions-neutral oil and natural gas could be highly valued by consumers, but the process would require careful measurement, monitoring and verification to ensure that it truly avoids any increase in emissions to the atmosphere.

Box 4.3 ▷ Norway's efforts to minimise emissions intensities

Norway is a significant oil and gas producer, accounting for 2% of global oil production in 2022 and 3% of global gas production. It is the third-largest natural gas exporter and seventh-largest net oil exporter in the world. According to the latest IEA data, Norway has the lowest emissions intensities of oil and gas production in the world.

The Norwegian government has made a concerted effort to decrease emissions from its oil and gas industries. Under the Paris Agreement, Norway's nationally determined contribution (NDC) commits to reducing net emissions by at least 50% and towards 55% by 2030 compared to 1990 levels and achieving carbon neutrality by 2050, which are more ambitious targets than those of the European Union. These NDC commitments were enshrined in law in 2017 when the country adopted the Climate Change Act. Additionally, the act sets the target of becoming a low-emissions society by 2050, equivalent to reducing greenhouse gas (GHG) emissions by around 90-95% from 1990 levels. The act includes steps for implementation, including a gradual increase in the taxation of GHG emissions not already included in the emissions trading system (ETS).

Norway implemented a carbon tax covering the fossil fuels and petroleum sector in 1991 – it was one of the first countries in the world to do so. The national CO_2 tax is currently about NOK 766/t CO_2-eq (USD 80/t CO_2-eq) for emissions outside the EU ETS. By 2030 the carbon tax is due to increase to NOK 2 000/t CO_2-eq. Approximately 85% of domestic GHG emissions are either covered by the EU ETS or subject to a CO_2 tax (or other GHG taxes), or both. Norway was also one of the first countries to place a ban on routine flaring, starting in 1971.

In 2016 the country's parliament adopted legislation mandating that Norway would become carbon-neutral by 2030 and set out policies to achieve this goal, including domestic reductions, international co-operation on emissions reductions, and project-based co-operation. As is the case for all major oil and gas producers, commitments on national emissions have not been accompanied by measures or policies to scale back domestic production.

Gain more value by cutting waste and stepping up non-combustion uses

Securing additional value from traditional supplies has multiple aspects and we zoom in here on two of them. The first, reducing flaring, is a short-term imperative; the second, finding additional non-combustion uses for hydrocarbons, plays out over the long term.

Substantial gas resources that are currently being produced do not make it to market because they are flared. Almost 140 bcm of natural gas was flared in 2022, a slight reduction year-on-year but still a vast waste of resources (World Bank, 2023b). Just five countries – Russia, Iraq, Iran, Algeria and Venezuela – that together produce just under one-quarter of oil production globally are responsible for more than half of flared volumes. Most flares operate on a continuous basis and many are located within 20 kilometres of existing gas pipelines. Reducing flaring can bring additional gas to market and generate additional revenues, and so many of the abatement options pay for themselves. For example, installing short pipelines is often an option to bring flared volumes to market and these can have a payback period of just a couple of years. Where putting new infrastructure in place is difficult, an increasing range of technologies are available to allow for local uses of gas as an alternative to flaring.

Even though much more remains to be done, there are many positive examples of what can be achieved under robust regulatory frameworks, and when governments and producers work together. For example, Nigeria has made a multi-year effort that reduced its flaring intensity by 55% between 2005 and 2015 (Box 4.4). Angola reduced flaring volumes by around 60% between 2016 and 2021 following its endorsement of the World Bank's Zero Routine Flaring by 2030 initiative.

Regulations need to address flaring and methane emissions in tandem, to avoid the unintended outcome where a requirement to reduce flaring creates an incentive to vent gas directly to the atmosphere instead. Colombia's 2022 regulation, for example, sets out requirements for methane mitigation and limits for gas flaring as well as methodologies to quantify flaring, venting and fugitive methane emissions (Colombia Ministry of Mines and Energy, 2022).

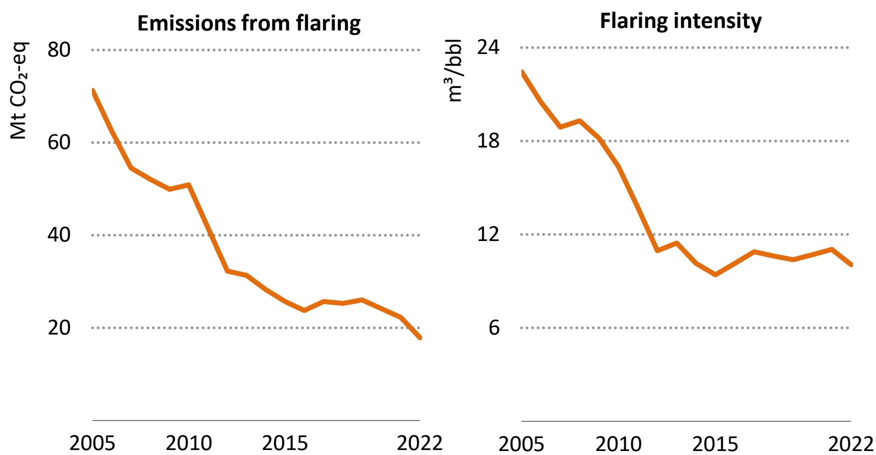
Box 4.4 ▷ Nigeria's efforts to cut flaring

The Nigerian government has introduced increasingly stringent legislation to reduce flaring from oil and gas operations. Nigeria was the first African country to establish a roadmap to restrict flaring with the 1979 Associated Gas Re-injection Act. Since then, the country has developed various regulations and plans that have targeted flaring, including the Nigeria Gas Master Plan and the Flare Gas (Prevention of Waste and Pollution) Regulation. Emissions from flaring fell by 65% between 2005 and 2015, from around 70 Mt CO_2-eq to 25 Mt CO_2-eq (Figure 4.16).

The flaring intensity in Nigeria has remained broadly constant since 2015 as the easiest projects to implement have been harnessed and many facilities struggle with ageing infrastructure. The country's updated NDC to the Paris Agreement, from 2021, includes reduction targets for gas flaring and venting, with quantifiable targets and detailed regulatory plans on how to operationalise the intended reductions. The updated NDC states the goal of ending routine flaring by 2030 and reducing fugitive methane emissions from oil and gas operations by 60% by 2031.

To meet these goals, in 2022 the Nigerian government issued guidelines to prevent and control the emission of GHGs from upstream oil and gas operations at new and existing facilities. For flaring, the guidelines prohibit cold venting (a waiver for operational exigencies is possible), require a combustion efficiency of at least 98% and set a series of repair requirements. Operators are also tasked with developing GHG management plans that include an inventory of emissions sources, accounting methodologies, and plans and timelines to reach net zero emissions. Producers need to regularly monitor and report flaring and venting volumes based on accurate and empirical measurements.

Figure 4.16 ▷ Emissions from and intensity of flaring in Nigeria, 2005-2022



New policies and regulations have spurred a significant reduction in flaring and in the flaring intensity of oil production in Nigeria.

Note: m^3/bbl = cubic metres per barrel.
Source: IEA analysis based on World Bank (2023b).

In recent years many producer economies have been building a host of new refineries with the aim of capturing more value from their hydrocarbon resources. The Middle East accounted for a quarter of new refining capacity that came online between 2015 and 2022. Some countries, such as Saudi Arabia and the United Arab Emirates, also made investments in overseas refineries, primarily in China and India. In 2022 Saudi Aramco acquired 30% of the 210 kb/d Gdansk refinery in Poland. In 2023 it announced two deals to acquire stakes in Chinese refineries, Rongsheng and ZPC, to secure outlets for its crude oil resources. For example, investment in the ZPC refinery involved a long-term crude supply agreement for 480 kb/d.

More recently, companies in producer economies have put more emphasis on petrochemicals as they expect oil demand for non-combustion uses to stay relatively robust in net zero transitions and their expansion projects to offer higher and more resilient margins. Many recent refineries are being developed as integrated facilities, either co-located with petrochemical facilities in the same industrial complex or more closely integrated. These integrated facilities produce a substantially higher share of petrochemical-related products and use less fuel than traditional refineries, and are better suited to serve changing oil product demand patterns in the APS and NZE Scenario. China's

Hengli Petrochemical refinery can produce over 40% petrochemical feedstock products compared with around 10% in typical refineries. Some are maximising the reforming of low-value naphtha to aromatics instead of gasoline.

Several new technologies are under development. High-severity fluid catalytic cracking (FCC) can produce petrochemicals from a low-value refinery stream. An "FCC to steam cracking" scheme could raise petrochemical yields to almost 70%. Saudi Arabia is pursuing a more ambitious scheme to convert crude oil directly into chemicals. While the cost and performance of this pathway are not yet fully proven, this "crude oil to chemical" technology has potential to increase the petrochemical yield to up to 80% of total output.

This kind of strategic reorientation towards non-combustion uses of hydrocarbon resources can help producer economies secure additional income streams against potentially declining fossil fuel revenue, but will require strengthened efforts to manage capital costs and develop the necessary skilled workforce.

4.4.2 Put domestic energy systems on a cleaner footing

Phase out inefficient fossil fuel subsidies

Pricing signals in many producer economies do not encourage clean or efficient choices by consumers or investors. Changing this inevitably requires revisiting the difficult issue of pricing reform and removal of fossil fuel subsidies. This is a socially and politically sensitive issue, as the expectation of cheap fuels is deeply rooted in many producer economies and subsidies are viewed as a means of sharing the benefits of the national resource endowment with populations. But it is nonetheless an essential reform if energy systems and economies are to be put on a more sustainable footing.

Even without subsidies, many producer economies still have a comparative advantage in energy, since their low oil and gas production costs and excellent renewable resources can provide stable and low domestic prices, especially for natural gas and electricity.

There are many examples of successful – and unsuccessful – attempts at pricing reform. Differing national circumstances mean that there is no single path to follow when reforming inefficient fossil fuel subsidies. However, successful efforts in the past suggest the following elements are essential ingredients:

- Prepare the ground with a comprehensive vision of the aims and stages of the reform process and a communication strategy that informs citizens of the need for reform and that it is being implemented in a just manner.
- Introduce reforms in stages to avoid too abrupt or there may be large price rises that may be difficult for some parts of the population to absorb.
- Ensure that pricing systems are transparent, well-monitored and enforced.
- Implement parallel reforms to protect vulnerable groups. There is a strong case for targeting conditional cash transfers at those who lack reliable access to clean cooking fuels and electricity.

- Anchor pricing reforms in a broader strategy that allows consumers to make more energy-efficient choices, e.g. by working with domestic producers and other suppliers to raise standards for efficient appliances and equipment.

Pricing reforms are often pushed through quickly at times of stress – these are the sorts of changes that are most prone to reversal. Durable reforms are typically planned and implemented over time, with inevitable adjustments for short-term circumstances but as part of an integrated vision for the direction of change. Since most subsidies benefit better-off segments of the population (who use more of the subsidised fuels), reforms are compatible with wider efforts to promote energy access and tackle energy poverty, which need to be much more targeted.

Box 4.5 ▹ Fossil fuel subsidy reform in Saudi Arabia

Historically, Saudi Arabia has extensively subsidised energy costs for domestic use, but it has implemented a number of changes as part of its Vision 2030 development plan. By and large, these have been relatively small and incremental steps, but the anticipated gains from reforms have been clearly articulated: to improve the fiscal position, incentivise sustainable patterns of consumption, promote a sound investment model for industrial development, and allow for a more targeted approach to benefits. Between 2015 and 2018 gasoline prices tripled and electricity prices doubled. In 2018 the government introduced a system of cash payments to Saudi citizens in lower- and middle-class households based on size and income, up to a certain threshold.

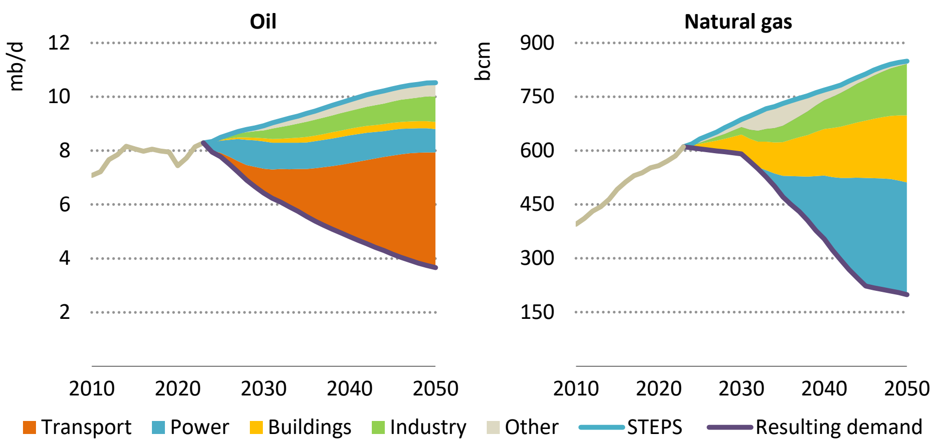
These efforts limited the subsidy for fossil fuel consumption, which in the Saudi case is mainly foregone revenue rather than an explicit payment from budgetary funds. Nonetheless subsidies remain substantial, averaging around USD 50 billion per year over the past five years (which included a large drop in 2020 followed by a substantial increase, reflecting changes in international prices). While momentum for large-scale pricing reforms has slowed in recent years, the authorities raised the price of diesel, which has been heavily subsidised, by 21% at the end of 2021 and by a further 19% at the end of 2022. Nonetheless, the diesel price remained around 80% lower than the global average in 2022, and the average electricity price for residential consumers was around 70% lower.

From very low domestic levels in the past, the price of energy in the largest producers has started to increase – Saudi Arabia is an example of gradual change (Box 4.5). Nigeria is now undergoing a much more accelerated process of reform and it is having much more substantial near-term impacts on consumption patterns and welfare. Pricing reforms in May 2023 tripled the price of petrol, nearly doubled some transport fares and significantly increased food prices; this resulted in an immediate hike in the inflation rate, which reached 23% in June, the highest rate in 17 years. Nigeria's average daily petrol consumption has fallen by 28% since the subsidies were scrapped. In response, the government declared a state of emergency on food security and decided to reallocate the expenditure that was used on subsidies to invest in the agricultural sector and to provide direct subsidies to farmers and low-income families.

Boost efficiency and clean energy deployment to reduce domestic oil and gas use

Domestic oil and gas demand is set to increase significantly in many of the producer economies in the coming years, driven by economic and population growth. In the Middle East,[2] for example, oil demand rises in the STEPS by more than 2 mb/d (a near 30% increase) and gas demand by 265 bcm (a 45% increase) to 2050. Much of this demand could be cost-effectively substituted with low-emissions sources, improving the overall efficiency of the energy system, allowing countries to meet export demand with lower investment in new supply, and reducing local air pollution as well as CO_2 emissions.

Figure 4.17 ▷ Potential reductions in domestic oil and gas demand in the Middle East by sector, 2010-2050



Around 7 mb/d of oil and 650 bcm of gas consumed domestically in 2050 could be avoided through efficiency efforts, electrification and other clean energy deployment.

The clearest opportunities to expand clean energy are in the power sector (Figure 4.17). Many producer economies, most notably in the Middle East and North Africa, have solar resources with some of the best potential in the world and these could provide the backbone for a significant reduction in both oil and gas use in the power sector. Currently more than 70% of the electricity generated in all the countries of the Middle East comes from natural gas and over 20% from oil. This is the highest share anywhere in the world; outside the Middle East, only

[2] Figures in this section on the Middle East include all countries in the region, including some that are not producer economies.

around 2% of electricity is generated from oil. A concerted effort to deploy renewables could displace around 1 mb/d of oil and 310 bcm of natural gas from the power sector by 2050.

Electricity use in buildings is the largest component of electricity consumption in the Middle East. With the large anticipated increase in the use of air conditioners, demand for space cooling alone could triple to 2050 (an increase of over 1 exajoule from 2022 levels). Power demand for air conditioning is generally higher during the daytime when solar PV generation is higher, reducing the risk of potential mismatches between power output and consumption. Improvements to efficiency through stringent standards for new and existing buildings, improvements in the efficiency performance of air conditioners, and the electrification of heating systems could free close to 200 bcm of natural gas use.

The Middle East has around 45 million cars in its current vehicle fleet, the vast majority relying on gasoline to fuel internal combustion engines (ICEs). Together with other road vehicles, these account for the bulk of oil demand in the transport sector. The fleet of cars is projected to increase and if this incremental demand for mobility is met with oil, as in the STEPS, it would lead oil demand in the transport sector to rise by more than 50% to 2050. Greater efficiency and electrification of transport could displace around 4 mb/d of oil in this sector.

4.4.3 Develop new low-emissions products and value chains

Step up production of low-emissions fuels

Clean electrification and efficiency are central pillars of rapid energy transitions, but they cannot carry the shift to a net zero emissions system on their own. In 2050 around 50% of final energy consumption is met by electricity in the NZE Scenario, but the remainder is met by a range of low-emissions fuels. While this is a very different landscape for fuel suppliers, it nonetheless means that expertise in the large-scale production, processing and transport of fuels remains a crucial area of expertise and commercial opportunity.

Low-emissions fuels include various sources of biofuels, hydrogen and hydrogen-based fuels. In addition, some fossil fuel use can be equipped with carbon capture, utilisation and storage (CCUS) to avoid CO_2 emissions. Developing production facilities for hydrogen and hydrogen-based fuels and deploying CCUS are particularly interesting avenues for producer economies (Box 4.6).

In Oman, for example, deploying low-emissions hydrogen in refining could cut annual emissions by more than 3 Mt CO_2 (4% of current emission levels). This new industry can also be a source of economic activity, inward investment and intellectual property exports. Renewable energy generation, electrolysis, power grids, CCUS and the production of ammonia, synthetic fuels and low-carbon steel could all play such a role in developing alternative sources of revenue; this is especially important in the APS and NZE Scenario where there are large falls in income from oil and gas. Finally, low-emissions fuels allow producers to leverage their existing strengths, resources and competencies in oil and gas for the new global energy economy.

Producer economies in Africa and the Middle East currently account for just under 5% of the low-emissions hydrogen production capacity under construction or consideration around the world, but this includes some of the largest individual projects. For example, the Helios Green Fuels project in Saudi Arabia, a USD 8.5 billion project that was approved for development in early 2023, will be able to provide around 0.2 Mt hydrogen per year and involves 4 GW of solar PV and wind power, 2 GW of electrolysis, and electricity storage. This is eight times larger than today's biggest operational project and 80 times larger than the biggest plant just two years ago.

In Oman, land leases were issued in June 2023 to three consortiums pursuing projects that will also have a capacity to produce around 0.5 Mt hydrogen per year; another project to build 5.5 GW of solar PV for a 350 MW electrolyser for ammonia production took final investment decision in July 2023. In Angola, the integration of new renewable capacity and ammonia manufacturing with around 300 MW of electrolysis is proposed for export from the middle of the decade. Two-thirds of the planned capacity in producer economies is to produce hydrogen or hydrogen-based fuels for export to overseas markets, and countries have signed numerous agreements with potential importers. A number of producer economies could produce some of the lowest-cost hydrogen available anywhere in the world, but policy support will initially be essential to scale this up (Figure 4.18).

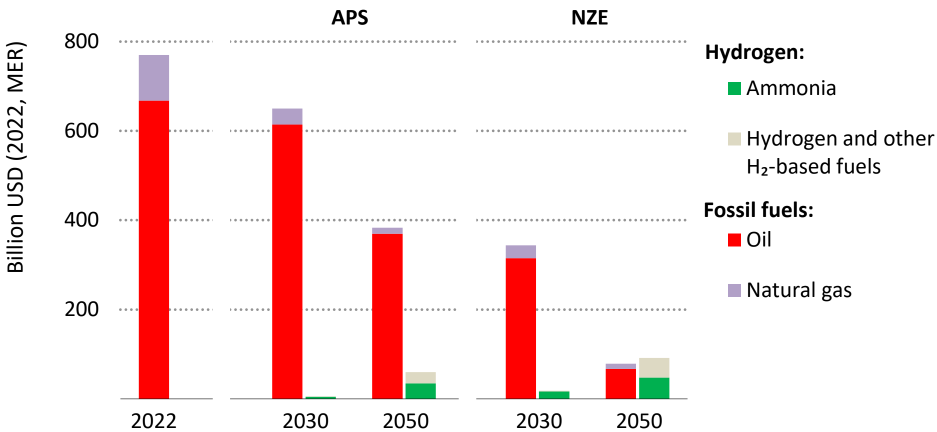
Figure 4.18 ▷ Estimated production costs for low-emissions hydrogen from renewables via electrolysis in producer economies, 2030

Some producer economies could produce low-emissions hydrogen at a much lower cost than global averages.

Note: Based on the costs of installing dedicated solar and wind electricity capacity in the lowest-cost combinations for the purposes of hydrogen production per 40 square kilometre (km^2) surface area.

Low-emissions fuels could create significant value for producer economies, but they are unlikely to replace more than a small part of today's fiscal and export revenues from fossil fuel activities (Figure 4.19). In the APS, hydrogen export revenues in the Middle East rise to around USD 60 billion in 2050, a major increase from today, but less than the USD 390 billion drop in income from oil and gas over this period. In the NZE Scenario, hydrogen export revenues from the Middle East rise to around USD 90 billion in 2050. This is a similar magnitude to oil and gas income at that time, but it is still much smaller than the USD 690 billion drop in income from oil and gas sales to 2050.

Figure 4.19 ▷ Income from low-emissions hydrogen and hydrogen-based fuels and oil and gas in the Middle East, APS and NZE Scenario



Exports of hydrogen and hydrogen-rich fuels are no substitute for the revenues from fossil fuels, although they could provide a durable source of economic advantage.

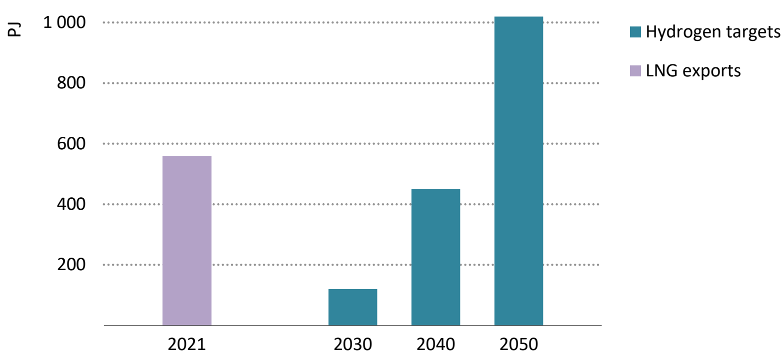
The development of a hydrogen production industry can lay the foundation for other industrial developments. This includes the production of higher-value commodities such as ammonia, steel, aviation fuel, methanol and other chemical products. It can also help broader emissions reduction efforts, even if the hydrogen itself is destined for export. For example, the output of a 4 GW renewable project would be larger than current total electricity generation in each of Guyana, Senegal and Suriname.

If grid-connected, just a fraction of this renewable electricity could be a valuable resource for managing the electricity network at key moments, and there are strong arguments for expanding clean power generation for local communities alongside that for hydrogen production. Its scale would also generate experience with finance, regulation, installation and operation, which would reduce costs for subsequent installations to meet growing domestic electricity demand from households and businesses or attract new energy-intensive customers.

Box 4.6 ▷ Oman's low-emissions hydrogen plans

Oil and gas represent around 60% of Oman's export income, but natural gas reserves are declining towards a level that could only cover existing domestic demand in the medium term and therefore not allow for export. It has announced a target to become net zero by 2050 and to produce at least 1 Mt of renewable hydrogen a year by 2030, up to 3.75 Mt by 2040 and 8.5 Mt by 2050. Oman benefits from high-quality solar PV and onshore wind resources, and has existing fossil fuel infrastructure that can be directly used or repurposed for low-emissions fuels. Oman also has large amounts of land that can be used for large-scale project development; to date, around 1 500 km^2 has been put aside with the potential to produce around 1 Mt/yr of renewable hydrogen. Around 50 000 km^2 has been identified as suitable for hydrogen production, enough for 25 Mt/yr (IEA, 2023).

Figure 4.20 ▷ Oman's LNG exports in 2021 and renewable hydrogen targets



Oman has ambitious targets for renewable hydrogen and most is intended for export

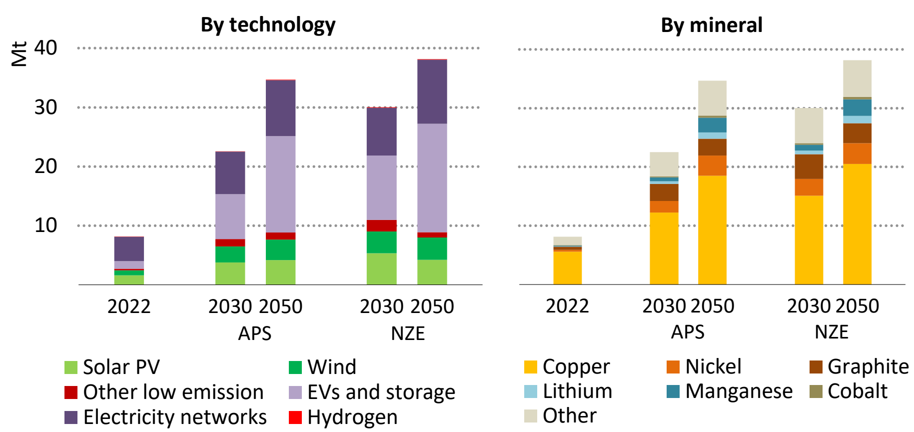
Most of the hydrogen is intended for export – the 2040 hydrogen target would represent 80% of its LNG exports today in energy-equivalent terms – but developing a domestic market can strengthen Oman's position while international demand grows (Figure 4.20). Oman's refining sector, for example, uses around 0.35 Mt of fossil hydrogen and this could be replaced by renewable hydrogen. Expanding renewables for hydrogen could also accelerate cost reductions for other renewable projects in the country, assist emission reductions in the country's power system (natural gas accounts for over 95% of the country's electricity generation today) and bolster natural gas export revenues by displacing domestic gas demand. Achieving Oman's 2030 hydrogen and power sector emissions reduction goals would require around USD 37 billion in investment. By then, exports and replacement of domestic natural gas use could generate an economic value of more than USD 2 billion a year, which could rise to double-digit USD billion levels in the long term.

To get projects moving will take a strongly collaborative mindset, both internationally and within countries. Low-emissions hydrogen and CCUS will not work easily, at least in the short term, unless the upstream, midstream and downstream explore greater integration and partnership, together with government. When a CCUS project is planned by a particular company, the initial costs can be hard to finance. But when initiatives are considered as part of a broader approach, where the costs of infrastructure can be shared within an industrial cluster, then the economic case can become much more attractive.

Expand into new clean energy supply chains

Alongside the ability to produce low-emissions energy, oil and gas producers also have opportunities for diversification in clean energy supply chains, including in critical minerals such as copper and lithium. The rapid deployment of clean energy technologies as part of net zero transitions is set to turbocharge demand for a range of critical minerals. In the APS, demand almost triples by 2030 and more than quadruples by 2050. In the NZE Scenario, an even faster deployment of clean energy technologies implies a nearly fourfold increase in demand for critical minerals in 2030 from today's level (Figure 4.21). Meeting these demands requires a significant ramp-up in mining and refining activities.

Figure 4.21 ▻ Mineral requirements for clean technologies in the APS and NZE Scenario



Clean energy technology demand for critical minerals could create new investment opportunities for the oil and gas sector.

Note: EVs = electric vehicles.

There are several similarities between oil and gas extraction and mineral extraction. Both require large capital expenditure, geological and engineering expertise, and strong capabilities to manage complex projects. An ability to work with governments in resource-holding nations and manage political risks are also common elements in both businesses. The mining of critical minerals generally involves higher rates of return than those in traditional oil and gas operations. These make critical mineral developments one of the opportunities for fossil fuel producers to diversify their businesses.

A number of oil and gas companies are looking closely at opportunities around critical mineral developments. Examples include the following:

- Oil refining operations provide key inputs such as needle coke, which is used to produce synthetic graphite for battery anodes. Phillips 66, a major refiner, established a partnership with Novonix to produce synthetic graphite anode materials using the specialty coke Phillips 66 produces.
- Oil and gas companies are making investments in lithium extraction and conversion businesses. Galp Energia established a joint venture with Northvolt to build a lithium hydroxide conversion plant. Some oil majors have ventured further into clean energy manufacturing. TotalEnergies' investments in battery manufacturing through Saft and the Automotive Cell Company are key examples.
- Oilfield service providers such as SLB and Halliburton are aiming to extend their chemical know-how to critical minerals. Specialised engineering and technology companies that have traditionally serviced the oil and gas sector such as Technip are starting to support the development of critical mineral refining and conversion facilities.

Lithium brine extraction is an area that is gaining significant traction in the oil and gas industry. Companies including Chevron, Equinor, ExxonMobil, Gazprom, Imperial, Oxy and YPF, and service companies like Baker Hughes and SLB are securing a stake in this emerging sector, investing or partnering with geothermal companies, mining juniors and chemical start-ups (Table 4.2). Among various lithium production routes, direct lithium extraction (DLE) has become a key focus of oil and gas companies. DLE technologies extract lithium from brine using filters, membranes or other equipment, removing the need for evaporation ponds. Groundwater aquifers hold large volumes of water with considerable amounts of dissolved mineral content, leading to large aggregate reserves. DLE technologies could help unlock this potential with relatively short lead times. The process is closer to a chemical business than a traditional mining business and therefore attracts interest from oil and gas companies with refining and chemical expertise. The possibility of extracting other metals, such as bromine, or generating geothermal power has the potential to increase profitability further, although challenges around scalability and water consumption need to be resolved. Current areas of interest for oil majors are Canada (Leduc oil fields in Alberta), the United States (Arkansas and Texas), Germany and France (Rhine Valley), as well as Russia (Box 4.7).

There are well-known synergies between the core expertise of oil and gas producers and geothermal-based lithium extraction. These involve knowledge and skills in geology and earth exploration, drilling and well construction, reservoir engineering and subsurface pumping in high-temperature and high-pressure environments. In July 2022 the US Department of Energy announced a USD 165 million initiative to address technology and knowledge gaps in geothermal energy, based on best practices used within the oil and gas industry.

Table 4.2 ▷ Oil and gas industry investment and partnerships in lithium and geothermal activities

Oil majors	Region	Focus	Activities
Chevron	United States	Geothermal	• Investment in Baseload Capital to develop geothermal projects in the United States (USD 24 million raised in 2022)
Equinor	France	Geothermal + lithium	• Investment in Lithium de France, junior miner (USD 55 million raised in 2023)
ExxonMobil	United States	Lithium	• Announced project to exploit lithium in Arkansas
Imperial	Canada	Lithium	• Investment in E3 Lithium, junior miner, with projects in Leduc oil fields
Gazprom	Russia	Lithium	• Partnering with Irkutsk Oil Company to exploit lithium in Kovykta gas field
Oxy	United States	Geothermal + lithium	• Joint venture with All-American Lithium to extract lithium from geothermal and brines
YPF	Argentina	Lithium	• Partnering with Catamarca Minera y Energética to prospect for lithium in the Fiambala salt flats
Oilfield services	**Region**	**Focus**	**Activities**
Baker Hughes	United States	Geothermal	• Investment in Greenfire Energy
SLB	United States	Geothermal + lithium	• Investment in EnergySource Minerals • Partnering with technology provider Gradiant for sustainable lithium compound production
Others	**Region**	**Focus**	**Activities**
Berkshire Hathaway Energy	United States	Geothermal + lithium	• Lithium and geothermal project in the Salton Sea, California
Koch	United States	Geothermal + lithium	• Investment in lithium extraction processes • Investment in Standard Lithium (USD 100 million) • Investment in Compass Minerals' Utah project, (USD 252 million)

Box 4.7 ▷ Identifying critical mineral opportunities in oil-rich countries

Certain oil-rich countries, such as Brazil, Canada, China, Russia and the United States, have already identified significant critical mineral reserves. This creates the opportunity to secure new revenue to compensate for the potential decline in fossil fuel demand in climate-driven scenarios. For example, Latin America is already a major player in critical minerals production, providing some 40% and 35% of global copper and lithium outputs respectively. The region holds sizeable resources of bauxite, graphite, nickel and rare earth elements. With rising demand for these minerals, it is estimated that the region's revenue from the production of these minerals could grow 1.5 times by 2030 in the APS without a further increase in market share. However, this is not the case for many producer economies in the Middle East and some African countries; resources in many oil-producing countries remain underexplored, and better geological data will need to be collected to understand better the size of the opportunities. Exploration is often the first step for countries wanting to develop their critical mineral potential. Some oil producers are already embarking on this. Saudi Arabia launched a USD 207 million geological mapping project of the Arabian shield. Similarly, the African Finance Corporation (AFC) recently partnered with the Nigerian mining sovereign wealth fund to develop mining projects in Nigeria, Africa's largest oil producer. Three lithium refining projects are also being developed in Saudi Arabia and the United Arab Emirates.

Infrastructure can play a key role in this transition. Several African oil producers, including Angola, the Democratic Republic of the Congo (DRC) and Zambia, are reactivating the railway corridor to the port of Lobito, partnering with commodity traders to seize economic opportunities related to their mineral resources. The world's largest copper-cobalt deposits are located in the DRC's copperbelt, and Angola has a number of critical mineral projects currently under development, including rare earth elements (Huambo province), lithium (Namibe province) and phosphates (Cabinda province).

Developing new industrial-scale mining projects often comes with a risk of environmental degradation and adverse impacts on local communities. Failing to consider these issues may make it difficult to obtain – and maintain – a social licence to operate and imperil clean energy transitions. International co-operation to promote sustainable and responsible development practices can help reduce these risks, including by encouraging due diligence and strengthening data collection and reporting mechanisms.

4.5 Working together to ensure equitable and just net zero pathways

4.5.1 Why should exporters and importers work together?

Net zero transitions can only occur smoothly if countries work together in a mutually beneficial manner. This includes countries with different interests and positions in oil and gas supply chains actively co-operating. As noted in a recent study, "nothing can replace the strong domestic policy stance needed to tackle the risk of Dutch Disease and the Resource Curse. But surely, the international community can do a lot more to support these domestic efforts" (van Hulst, 2023). This would help accelerate efforts to achieve net zero and economic transitions and could reduce disruptions and geopolitical tensions. Common goals for co-operation include:

Foster mutual understanding and reduce the risk of high and volatile prices. The sequencing of changes in fossil fuel demand and supply is a critical issue for orderly transitions, and dialogue between importers and exporters can help to mitigate the risk of market disruption. It is important for producers and exporters to understand how major consuming countries view the outlook for demand and the dynamism of changes that could restrain it. If producers are unable to manage the extreme strains that would be placed on their fiscal balances by lower prices in net zero transitions, this could also lead to turbulent and volatile markets.

Avoid a "race to the bottom" for oil and gas extraction. Governments around the world will face difficult choices about how much income to retain from oil and gas companies' dwindling revenues. While governments, especially those with higher cost resources, may relax fiscal terms on extraction to protect local industries, this would reduce their income and could be perceived as offering support to the oil and gas industry even as the world is transitioning away from fossil fuels. In the NZE Scenario it is assumed that countries do not reduce government tax takes except where oil prices fall far below the marginal cost of production. This helps to avoid a "race to the bottom" that would further reduce the income governments in producer economies receive from oil and gas sales.

4

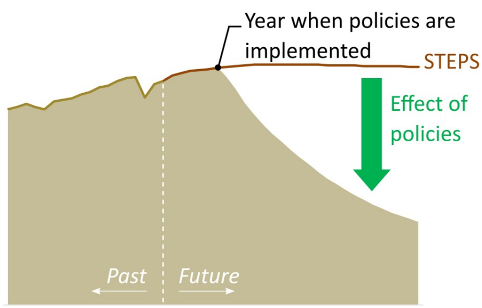
Pay attention to the allocation of rents from fossil fuel extraction and use. The reduction in oil and gas demand and prices through climate policies introduced by consumer countries could reallocate the income generated from the extraction and use of fossil fuels from producer economies to consumer countries (Box 4.8). Different climate policies affect the magnitude of this swing in different ways and by working together producer and consumer countries can address the undesirable impacts of a redistribution of income between and within countries. For example, it may be possible to levy CO_2 pricing at the point of export rather than via border adjustments in the importing region.

Minimise incentives to invest in ways that undermine net zero transitions. By providing greater visibility on their demand-side policy goals, and stable regulatory regimes to deliver them, consumer countries can help producer economies plan their oil and gas investment strategies and fiscal regimes. Regular dialogue about demand and supply outlooks can also assist. These approaches would reduce the risk of overinvestment in new oil and gas capacity that could undermine overall efforts to reduce emissions and the risk that investment in new oil and gas capacity cannot be recouped.

The prospect of lower future revenues from oil and gas in net zero transitions may also incentivise producer economies to expand production in the near term, reducing prices and potentially boosting near-term consumption (a tension known as the "green paradox" [Figure 4.22]) (Bauer, et al., 2018). In the NZE Scenario, consumer economies avoid this by ensuring near-term policies are sufficiently strong to counteract any effect of lower prices on demand. They could, for example, implement policies that swap combustion equipment for heaters and motors that are incompatible with fossil fuel, or prohibit ICE cars, which would reduce demand even before the ban comes into force as carmakers ramp up EV production and the ICE vehicle fleet shrinks.

Support producer economies to accelerate economic diversification. In addition to diversifying public revenue beyond the energy sector (Section 4.2.2), producer economies can be helped to develop new models of resource development, whether focused on CCUS, trade in hydrogen, or non-combustion uses for hydrocarbons. Policy signals and investment support from potential consumers of these resources will be fundamentally important. Given the abundant renewable resources of many producer economies, producer economies could also attract electricity-intensive industries looking to locate in areas that can best provide low-cost emissions-free electricity. Similarly, existing subsurface data and expertise in producer economies position them well to develop CO_2 storage resources, potentially making them attractive locations for new heavy industries and CO_2 removals. Cross-border support, including financial and technical assistance, can help with this, although the collective global need for clean energy technology deployment needs to be balanced by the desire of countries to promote domestic job creation and local commercial advantages and to ensure that clean energy supply chains are as resilient and low-cost as possible.

Figure 4.22 ▹ How the anticipation of future climate policies can lead to the green paradox



Oil producers anticipate the risk that future climate and energy policies will reduce demand below previous expectations...

... by raising production before the policies are implemented, reducing prices and boosting near-term demand.

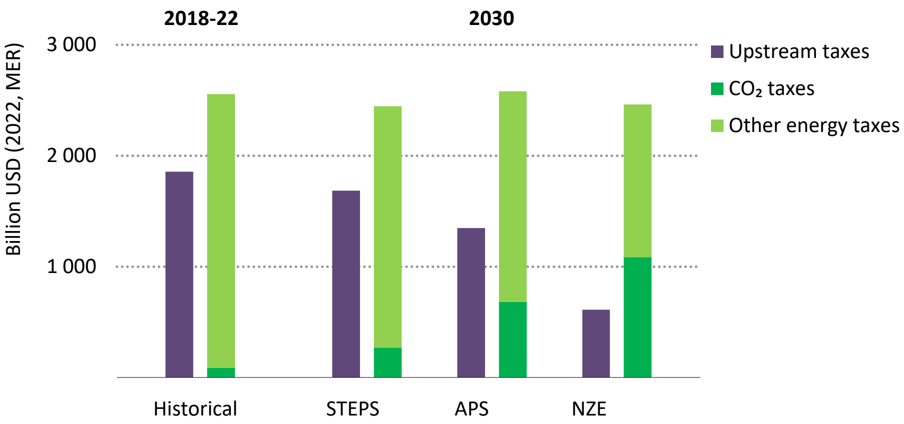
Unless carefully designed, the announcement of future climate and energy policies could encourage oil and gas producers to expand production in the near term.

Accelerate global clean energy transitions. Producer economies will be critical to the development of a number of clean energy technologies needed in net zero transitions. They are well placed to support large-scale market expansion for CO_2 capture equipment, electrolysers, energy storage installations and other equipment that will propel them along the learning curve. Some of these effects will accrue from economies of scale, and the impacts of scaling up the capacity of installers, industrial relationships and efficient supply chains could be even more significant. Producer economies are already leading the way on some technologies: the size and ambition of their proposed hydrogen projects and their partnerships with international exports mean they are already near the global technological frontier for hydrogen production from renewable electricity.

Box 4.8 ▷ Tax revenues from the production and use of oil and gas

Governments around the world collect a large amount of income from the production and use of oil and gas. Almost USD 2 trillion was collected annually through oil and gas production taxes, production-sharing agreements, and domestic income generated by NOCs between 2018 and 2022 (around half of gross revenues generated by the industry). Over the same period, governments collected around USD 2.5 trillion annually through energy, excise and value-added taxes on oil and gas use (Figure 4.23). A further USD 90 billion was collected globally through CO_2 prices on oil and gas use.

Figure 4.23 ▷ Annual average government revenue from oil and gas by scenario



Net zero transitions see a transfer in rents from producer to consumer economies as taxes from oil and gas extraction fall and CO_2 taxes on oil and gas use rise.

In the APS and the NZE Scenario, reductions in oil and gas demand and prices, alongside a slight drop in the government share of gross oil and gas revenue, results in a large drop in production taxes (they fall by around USD 1.2 trillion in the NZE Scenario to 2030). Tax revenue from oil and natural gas use falls due to efficiency improvements, the rise in electric mobility, and heating powered by renewable technologies. These reductions are almost wholly offset by a rise in taxes generated by CO_2 prices, which increase by USD 1 trillion in the NZE Scenario to 2030. Much of this represents a sizeable transfer of oil and gas rents from producer to consuming economies. However, the effect is partly mitigated by policies such as renewable energy targets and bans on ICEs that limit the need for CO_2 pricing to be the spur for the uptake of clean energy.

Aligning expectations on the demand and supply of low-emissions fuels would also be mutually beneficial. There is considerable interest in investment in low-emissions fuels in producer economies, but uncertainty persists about how quickly demand for the various fuels will materialise in consumer countries. Close co-ordination between consumers and producers is essential to the scale-up of a new international industry that requires new, extensive capital-intensive infrastructure.

4.5.2 How can exporters and importers work together?

Importing countries can work with export partners in several ways to build upon their shared interests. In a world where demand for energy services is increasing, resource-rich countries will continue to seek value from their endowments, hydrocarbon or otherwise, and importers will value secure, affordable energy supplies. The task ahead is to make these quests compatible with net zero transitions and the gathering pace of change in global energy. There are four main routes to promoting effective international co-operation in this area: ensuring the right market signals; co-operating to unlock investment in low-emissions fuel trade; collaboration on technology; and bilateral and multilateral engagement. Several examples exist of existing policy efforts looking to promote action in these areas (Table 4.3).

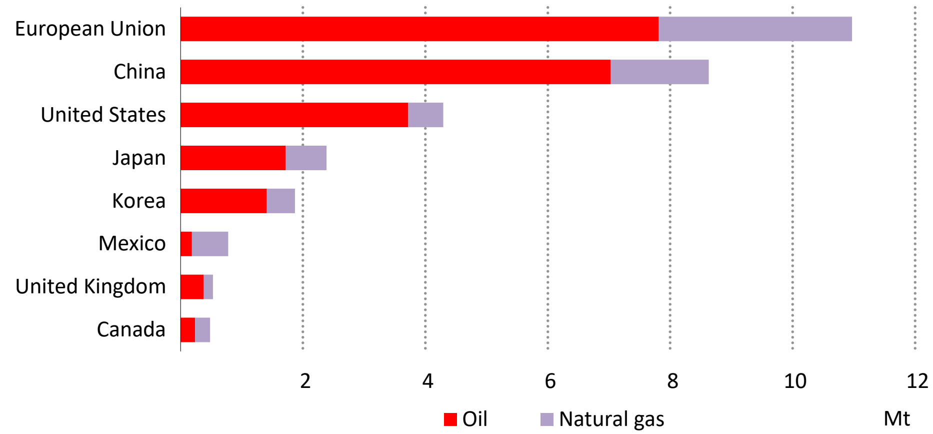
Table 4.3 ▷ Pillars of co-operation between importers and exporters for secure and orderly energy transitions

Pillar	Leading party	Main elements	Examples
Ensure the right market signals	Oil and natural gas importers	Place economic value on oil and gas with low emissions intensity	• EU regulation on methane emissions reduction in the energy sector • Joint Declaration from Energy Importers and Exporters on Reducing Greenhouse Gas Emissions from Fossil Fuels
		Align policies and regulations on oil and gas use with stated climate targets	• EU 2035 ban on sales of ICE cars • Canada Clean Fuel Regulations • India 2022 ban on single-use plastics
		Create demand for low-emissions fuels and products	• EU proposed Carbon Border Adjustment Mechanism • “First-mover coalitions” for low-emissions products • US Inflation Reduction Act tax credits
Co-operate to unlock investment in low-emissions fuel trade	Importers and exporters	Sign memorandums of understanding for co-operation on studies and projects	• Agreements on hydrogen projects between European countries, Japan and producer economies
		Importers facilitate or underwrite multi-year offtake contracts	• H2Global “double auction” model to bridge cost gaps between producers and users and proposed international leg of the European Hydrogen Bank
		Enable investment in infrastructure, including ports, storage and pipelines	• World Bank USD 350 million commitment to Chile for hydrogen • US-UAE Partnership to Accelerate Transition to Clean Energy

Pillar	Leading party	Main elements	Examples
Collaborate on technology	Advanced economies, research institutes, oil and gas industry	Co-fund pilot and demonstration projects	• Germany has announced financing for a hydrogen demonstration project in Morocco • Governments commit to purchasing offsets from early projects in developing countries, such as the proposed direct air capture demonstration in Kenya • In Salah CCUS project in Algeria funded by oil and gas companies
		Support CO_2 storage resource exploration and development	• World Bank Carbon Capture and Storage Trust Fund for South Africa • Japan-Malaysia study on CO_2 storage
		Programmes that nurture start-ups in producer economies	• Netherlands' Invest International "Dutch Desk Nigeria" • Innovation Norway support to start-ups moving abroad
		Joint R&D programmes that enhance local technical capacities and skills	• UK Ayrton Fund • Mission Innovation calls for joint projects • Asian Development Bank support for the Indonesia centre for excellence for CCS/CCUS
Enter bilateral and multilateral dialogue	Importers and exporters	Producer and consumer forums, including for clean energy topics	• Net-Zero Producers Forum • The LNG Producer and Consumer Dialogues • Clean Energy Ministerial initiatives, especially on CCUS and hydrogen
		Work toward agreeing international standards	• UN Oil & Gas Methane Partnership 2.0 • IPHE work on emissions intensity definitions for hydrogen
		Wider economic transformation	• Saudi Japan Vision 2030

One area where producer and consumer economies can work together is on tackling methane emissions. We estimate, for example, that the energy system in the European Union results in around 11 Mt of methane emissions overseas during the production and extraction of the oil and gas that it imports (Figure 4.24). If consumer economies send support or signals to producer economies – which could take the form of financial and technical assistance, financial penalties such as CO_2 border taxes, or import restrictions – producer economies would have a clear incentive to reduce these emissions. For example, the recent provisional agreement on a new EU regulation on methane emissions reduction in the energy sector requires that new import contracts for oil, gas and coal entered into after 2027 follow EU methane management standards and sets maximum methane intensity levels from 2030. It also establishes a methane transparency database, methane performance metrics, and a rapid alert mechanism for super-emitting events.

Figure 4.24 ▷ Methane emissions of imported oil and gas in selected countries and regions, 2022



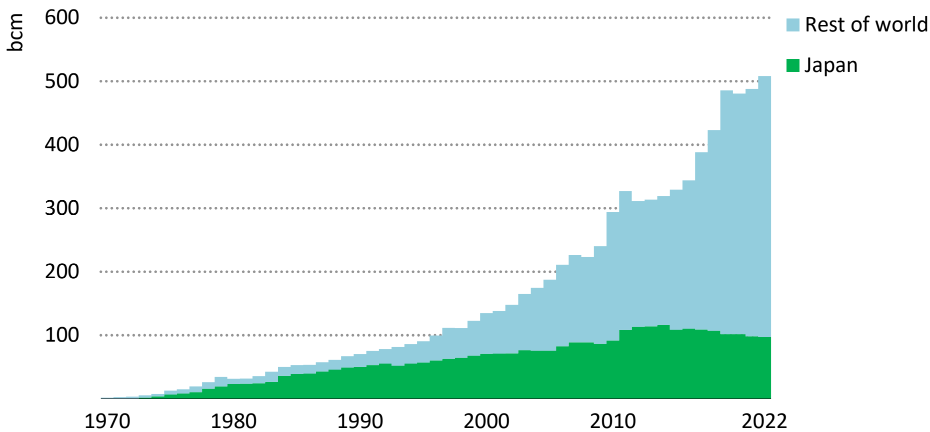
Oil and gas importers can assist exporters in reducing the 30 million tonnes of methane emitted per year from hydrocarbon extraction to meet demand from these eight regions.

A number of producer economies have announced plans to work with consuming countries to scale up clean energy exports. For their plans to be realised, importers need to support the investment case through co-operation on import demand and infrastructure. For example, the value chain for large-scale trade in hydrogen-based fuels is complex and includes hydrogen production, water supply, ammonia manufacture, energy storage, import and export terminals, pipelines, ships and either renewable electricity generation or CO_2 storage.

The first phases of such development could bear a close resemblance to the initial scale-up of the LNG market, with importers seeking access to new supplies sharing much of the risk with the operators of export infrastructure. Japan was a frontrunner in the development of the LNG market and it held a 75% share of global LNG trade through to the late 1980s due to its active development of contracting and co-investment (Figure 4.25). This enabled the globalisation of the market on common principles. Japan's share fell below 20% in 2022, by which time a much more liquid market had developed alongside the initial model of long-term offtake contracts.

Ultimately, secure and orderly energy transitions will only unfold with countries working together in a coalition that recognises their shared interests. For producer economies, effective multi-year programmes and partnership could be designed with the close involvement of international finance, including multilateral development banks. Increasing the resilience of major producer economies, particularly as energy transitions gather pace, is a matter of great importance beyond the producers themselves. It is integral to ensuring secure energy flows that provide producers with sufficient capital to finance the large-scale changes required by their economies, while ensuring consumers have a stable supply of energy as they make the shift to a net zero emissions future.

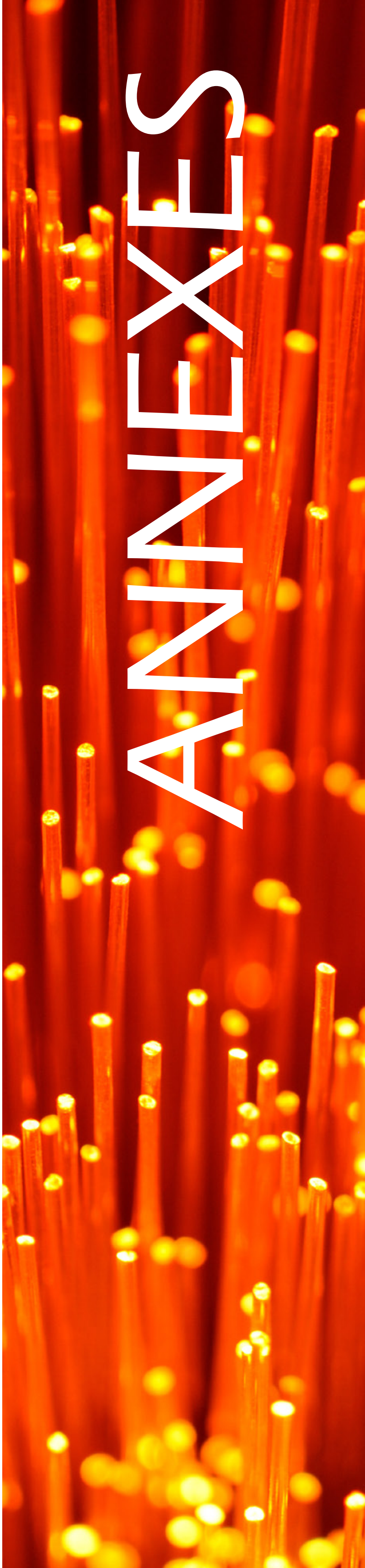
Figure 4.25 ▷ Global LNG imports by destination



IEA. CC BY 4.0.

Japan played an instrumental role in catalysing the global trade in LNG, before its share of imports declined from 75% to 20% as the international market became established.

ANNEXES



Definitions

This annex provides general information on terminology used throughout this report including: units and general conversion factors; definitions of fuels, processes and sectors; regional and country groupings; and abbreviations and acronyms.

Units

Area	km^2	square kilometre
	Mha	million hectares
Batteries	Wh/kg	watt hours per kilogramme
Coal	Mtce	million tonnes of coal equivalent (equals 0.7 Mtoe)
Distance	km	kilometre
Emissions	ppm	parts per million (by volume)
	t CO_2	tonnes of carbon dioxide
	Gt CO_2-eq	gigatonnes of carbon-dioxide equivalent (using 100-year global warming potentials for different greenhouse gases)
	kg CO_2-eq	kilogrammes of carbon-dioxide equivalent
	g CO_2/km	grammes of carbon dioxide per kilometre
	g CO_2/kWh	grammes of carbon dioxide per kilowatt-hour
	kg CO_2/kWh	kilogrammes of carbon dioxide per kilowatt-hour
Energy	EJ	exajoule (1 joule x 10^{18})
	PJ	petajoule (1 joule x 10^{15})
	TJ	terajoule (1 joule x 10^{12})
	GJ	gigajoule (1 joule x 10^{9})
	MJ	megajoule (1 joule x 10^{6})
	Boe	barrel of oil equivalent
	Toe	tonne of oil equivalent
	Ktoe	thousand tonnes of oil equivalent
	Mtoe	million tonnes of oil equivalent
	bcme	billion cubic metres of natural gas equivalent
	MBtu	million British thermal units
	kWh	kilowatt-hour
	MWh	megawatt-hour
	GWh	gigawatt-hour
	TWh	terawatt-hour
	Gcal	gigacalorie
Gas	bcm	billion cubic metres
	tcm	trillion cubic metres
Mass	kg	kilogramme
	t	tonne (1 tonne = 1 000 kg)
	kt	kilotonne (1 tonne x 10^{3})
	Mt	million tonnes (1 tonne x 10^{6})
	Gt	gigatonne (1 tonne x 10^{9})

Monetary	USD million	1 US dollar x 10^6
	USD billion	1 US dollar x 10^9
	USD trillion	1 US dollar x 10^{12}
	USD/t CO_2	US dollars per tonne of carbon dioxide
Oil	barrel	one barrel of crude oil
	kb/d	thousand barrels per day
	mb/d	million barrels per day
	mboe/d	million barrels of oil equivalent per day
Power	W	watt (1 joule per second)
	kW	kilowatt (1 watt x 10^3)
	MW	megawatt (1 watt x 10^6)
	GW	gigawatt (1 watt x 10^9)
	TW	terawatt (1 watt x 10^{12})

General conversion factors for energy

		Multiplier to convert to:					
		EJ	Gcal	Mtoe	MBtu	bcme	GWh
Convert from:	EJ	1	2.388×10^8	23.88	9.478×10^8	27.78	2.778×10^5
	Gcal	4.1868×10^{-9}	1	10^{-7}	3.968	1.163×10^{-7}	1.163×10^{-3}
	Mtoe	4.1868×10^{-2}	10^7	1	3.968×10^7	1.163	11 630
	MBtu	1.0551×10^{-9}	0.252	2.52×10^{-8}	1	2.932×10^{-8}	2.931×10^{-4}
	bcme	0.036	8.60×10^6	0.86	3.41×10^7	1	9 999
	GWh	3.6×10^{-6}	860	8.6×10^{-5}	3 412	1×10^{-4}	1

Note: There is no generally accepted definition of barrel of oil equivalent (boe); typically the conversion factors used vary from 7.15 to 7.40 boe per tonne of oil equivalent. Natural gas is attributed a low heating value of 1 MJ per 44.1 kg. Conversions to and from billion cubic metres of natural gas equivalent (bcme) are given as representative multipliers but may differ from the average values obtained by converting natural gas volumes between IEA balances due to the use of country-specific energy densities. Lower heating values (LHV) are used throughout.

Currency conversions

Exchange rates *(2022 annual average)*	**1 US dollar (USD) equals:**
British Pound	0.81
Chinese Yuan Renminbi	6.74
Euro	0.95
Indian Rupee	78.60
Japanese Yen	131.50

Source: OECD Data (database): Exchange rates (indicator), https://data.oecd.org/conversion/exchange-rates.htm, accessed October 2023.

Definitions

Advanced bioenergy: Sustainable fuels produced from wastes, residues and non-food crop feedstocks (excluding traditional uses of biomass), which are capable of delivering significant life cycle greenhouse gas emissions savings compared with fossil fuel alternatives and of minimising adverse sustainability impacts. Advanced bioenergy feedstocks either do not directly compete with food and feed crops for agricultural land or are only developed on land previously used to produced food crop feedstocks for biofuels.

Agriculture: Includes all energy used on farms, in forestry and for fishing.

Agriculture, forestry and other land use (AFOLU) **emissions:** Includes greenhouse gas emissions from agriculture, forestry and other land use.

Ammonia (NH_3)**:** Is a compound of nitrogen and hydrogen. It can be used as a feedstock in the chemical sector, as a fuel in direct combustion processes in fuel cells, and as a hydrogen carrier. To be considered a low-emissions fuel, ammonia must be produced from hydrogen in which the electricity used to produce the hydrogen is generated from low-emissions generation sources. Produced in such a way, ammonia is considered a low-emissions hydrogen-based liquid fuel.

Aviation: This transport mode includes both domestic and international flights and their use of aviation fuels. Domestic aviation covers flights that depart and land in the same country; flights for military purposes are included. International aviation includes flights that land in a country other than the departure location.

Back-up generation capacity: Households and businesses connected to a main power grid may also have a source of back-up power generation capacity that, in the event of disruption, can provide electricity. Back-up generators are typically fuelled with diesel or gasoline. Capacity can be as little as a few kilowatts. Such capacity is distinct from mini-grid and off-grid systems that are not connected to a main power grid.

Battery storage: Energy storage technology that uses reversible chemical reactions to absorb and release electricity on demand.

Biodiesel: Diesel-equivalent fuel made from the transesterification (a chemical process that converts triglycerides in oils) of vegetable oils and animal fats.

Bioenergy: Energy content in solid, liquid and gaseous products derived from biomass feedstocks and biogas. It includes solid bioenergy, liquid biofuels and biogases. Excludes hydrogen produced from bioenergy, including via electricity from a biomass-fired plant, as well as synthetic fuels made with CO_2 feedstock from a biomass source**.**

Biogas: A mixture of methane, CO_2 and small quantities of other gases produced by anaerobic digestion of organic matter in an oxygen-free environment.

Biogases: Include both biogas and biomethane.

Biogasoline: Includes all liquid biofuels (advanced and conventional) used to replace gasoline.

Biojet kerosene: Kerosene substitute produced from biomass. It includes conversion routes such as hydroprocessed esters and fatty acids (HEFA) and biomass gasification with Fischer-Tropsch. It excludes synthetic kerosene produced from biogenic carbon dioxide.

Biomethane: Biomethane is a near-pure source of methane produced either by "upgrading" biogas (a process that removes any carbon dioxide and other contaminants present in the biogas) or through the gasification of solid biomass followed by methanation. It is also known as renewable natural gas.

Buildings: The buildings sector includes energy used in residential and services buildings. Services buildings include commercial and institutional buildings and other non-specified buildings. Building energy use includes space heating and cooling, water heating, lighting, appliances and cooking equipment.

Bunkers: Includes both international marine bunker fuels and international aviation bunker fuels.

Capacity credit: Proportion of the capacity that can be reliably expected to generate electricity during times of peak demand in the grid to which it is connected.

Carbon capture, utilisation and storage (CCUS): The process of capturing carbon dioxide emissions from fuel combustion, industrial processes or directly from the atmosphere. Captured CO_2 emissions can be stored in underground geological formations, onshore or offshore, or used as an input or feedstock in manufacturing.

Carbon dioxide (CO_2): A gas consisting of one part carbon and two parts oxygen. It is an important greenhouse (heat-trapping) gas.

Chemical feedstock: Energy vectors used as raw materials to produce chemical products. Examples are crude oil-based ethane or naphtha to produce ethylene in steam crackers.

Clean cooking systems: Cooking solutions that release less harmful pollutants, are more efficient and environmentally sustainable than traditional cooking options that make use of solid biomass (such as a three-stone fire), coal or kerosene. This refers to improved cook stoves, biogas/biodigester systems, electric stoves, liquefied petroleum gas, natural gas or ethanol stoves.

Clean energy: In *power*, clean energy includes: renewable energy sources, nuclear power, fossil fuels fitted with CCUS, hydrogen and ammonia; battery storage; and electricity grids. In *efficiency*, clean energy includes energy efficiency in buildings, industry and transport, excluding aviation bunkers and domestic navigation. In *end-use applications*, clean energy includes: direct use of renewables; electric vehicles; electrification in buildings, industry and international marine transport; CCUS in industry and direct air capture. In *fuel supply*, clean energy includes low-emissions fuels, direct air capture, and measures to reduce the emissions intensity of fossil fuel production.

Coal: Includes both primary coal, i.e. lignite, coking and steam coal, and derived fuels, e.g. patent fuel, brown-coal briquettes, coke-oven coke, gas coke, gas works gas, coke-oven gas, blast furnace gas and oxygen steel furnace gas. Peat is also included.

Coalbed methane (CBM)**:** Category of unconventional natural gas that refers to methane found in coal seams.

Coal-to-gas (CTG)**:** Process in which coal is first turned into syngas (a mixture of hydrogen and carbon monoxide) and then into synthetic methane.

Coal-to-liquids (CTL)**:** Transformation of coal into liquid hydrocarbons. One route involves coal gasification into syngas (a mixture of hydrogen and carbon monoxide), which is processed using Fischer-Tropsch or methanol-to-gasoline synthesis. Another route, called direct-coal liquefaction, involves reacting coal directly with hydrogen.

Coking coal: Type of coal that can be used for steel making (as a chemical reductant and a source of heat), where it produces coke capable of supporting a blast furnace charge. Coal of this quality is commonly known as metallurgical coal.

Concentrating solar power (CSP)**:** Thermal power generation technology that collects and concentrates sunlight to produce high temperature heat to generate electricity.

Conventional liquid biofuels: Fuels produced from food crop feedstocks. Commonly referred to as first generation biofuels and include sugar cane ethanol, starch-based ethanol, fatty acid methyl ester (FAME), straight vegetable oil (SVO) and hydrotreated vegetable oil (HVO) produced from palm, rapeseed or soybean oil.

Critical minerals: A wide range of minerals and metals that are essential in clean energy technologies and other modern technologies and have supply chains that are vulnerable to disruption. Although the exact definition and criteria differ among countries, critical minerals for clean energy technologies typically include chromium, cobalt, copper, graphite, lithium, manganese, molybdenum, nickel, platinum group metals, zinc, rare earth elements and other commodities, as listed in the Annex of the IEA special report on the *Role of Critical Minerals in Clean Energy Transitions* available at: https://www.iea.org/reports/the-role-of-critical-minerals-in-clean-energy-transitions.

Decomposition analysis: Statistical approach that decomposes an aggregate indicator to quantify the relative contribution of a set of pre-defined factors leading to a change in the aggregate indicator. The *World Energy Outlook* uses an additive index decomposition of the type Logarithmic Mean Divisia Index (LMDI).

Demand-side integration (DSI)**:** Consists of two types of measures: actions that influence load shape such as energy efficiency and electrification; and actions that manage load such as demand-side response measures.

Demand-side response (DSR)**:** Describes actions which can influence the load profile such as shifting the load curve in time without affecting total electricity demand, or load shedding such as interrupting demand for a short duration or adjusting the intensity of demand for a certain amount of time.

Direct air capture (DAC)**:** A type of CCUS that captures CO_2 directly from the atmosphere using liquid solvents or solid sorbents. It is generally coupled with permanent storage of the CO_2 in deep geological formations or its use in the production of fuels, chemicals, building materials or other products. When coupled with permanent geological CO_2 storage, DAC is a carbon removal technology, and it is known as direct air capture and storage (DACS).

Dispatchable generation: Refers to technologies whose power output can be readily controlled, i.e. increased to maximum rated capacity or decreased to zero in order to match supply with demand.

Electric arc furnace: Furnace that heats material by means of an electric arc. It is used for scrap-based steel production but also for ferroalloys, aluminium, phosphorus or calcium carbide.

Electric vehicles (EVs)**:** Electric vehicles comprise of battery electric vehicles (BEV) and plug-in hybrid vehicles.

Electricity demand: Defined as total gross electricity generation less own use generation, plus net trade (imports less exports), less transmission and distribution losses.

Electricity generation: Defined as the total amount of electricity generated by power only or combined heat and power plants including generation required for own use. This is also referred to as gross generation.

Electrolysis: Process of converting electric energy to chemical energy. Most relevant for the energy sector is water electrolysis, which splits water molecules into hydrogen and oxygen molecules. The resulting hydrogen is called electrolytic hydrogen.

End-use sectors: Include industry, transport, buildings and other, i.e., agriculture and other non-energy use.

Energy-intensive industries: Includes production and manufacturing in the branches of iron and steel, chemicals, non-metallic minerals (including cement), non-ferrous metals (including aluminium), and paper, pulp and printing.

Energy-related and industrial process CO_2 emissions: Carbon dioxide emissions from fuel combustion, industrial processes, and fugitive and flaring CO_2 from fossil fuel extraction. Unless otherwise stated, CO_2 emissions in the *World Energy Outlook* refer to energy-related and industrial process CO_2 emissions.

Energy sector greenhouse gas (GHG) **emissions:** Energy-related and industrial process CO_2 emissions plus fugitive and vented methane (CH_4) and nitrous dioxide (N_2O) emissions from the energy and industry sectors.

Energy services: See useful energy.

Ethanol: Refers to bioethanol only. Ethanol is produced from fermenting any biomass high in carbohydrates. Currently ethanol is made from starches and sugars, but second-generation technologies will allow it to be made from cellulose and hemicellulose, the fibrous material that makes up the bulk of most plant matter.

Fischer-Tropsch synthesis: Catalytic process to produce synthetic fuels, e.g. diesel, kerosene or naphtha, typically from mixtures of carbon monoxide and hydrogen (syngas). The inputs to Fischer-Tropsch synthesis can be from biomass, coal, natural gas, or hydrogen and CO_2.

Fossil fuels: Include coal, natural gas and oil.

Gaseous fuels: Include natural gas, biogases, synthetic methane and hydrogen.

Gases: See gaseous fuels.

Gas-to-liquids (GTL)**:** A process that reacts methane with oxygen or steam to produce syngas (a mixture of hydrogen and carbon monoxide) followed by Fischer-Tropsch synthesis. The process is similar to that used in coal-to-liquids.

Geothermal: Geothermal energy is heat from the sub-surface of the earth. Water and/or steam carry the geothermal energy to the surface. Depending on its characteristics, geothermal energy can be used for heating and cooling purposes or be harnessed to generate clean electricity if the temperature is adequate.

Heat (end-use)**:** Can be obtained from the combustion of fossil or renewable fuels, direct geothermal or solar heat systems, exothermic chemical processes and electricity (through resistance heating or heat pumps which can extract it from ambient air and liquids). This category refers to the wide range of end-uses, including space and water heating, and cooking in buildings, desalination and process applications in industry. It does not include cooling applications.

Heat (supply)**:** Obtained from the combustion of fuels, nuclear reactors, large-scale heat pumps, geothermal or solar resources. It may be used for heating or cooling, or converted into mechanical energy for transport or electricity generation. Commercial heat sold is reported under total final consumption with the fuel inputs allocated under power generation.

Heavy-duty vehicles (HDVs): Include both medium freight trucks (gross weight 3.5 to 15 tonnes) and heavy freight trucks (gross weight >15 tonnes).

Heavy industries: Iron and steel, chemicals and cement.

Hydrogen: Hydrogen is used in the energy system as an energy carrier, as an industrial raw material, or is combined with other inputs to produce hydrogen-based fuels. Unless otherwise stated, hydrogen in this report refers to low-emissions hydrogen.

Hydrogen-based fuels: See low-emissions hydrogen-based fuels.

Hydropower: Refers to the electricity produced in hydropower projects, with the assumption of 100% efficiency. It excludes output from pumped storage and marine (tide and wave) plants.

Improved cook stoves: Intermediate and advanced improved biomass cook stoves (ISO tier > 1). It excludes basic improved stoves (ISO tier 0-1).

Industry: The sector includes fuel used within the manufacturing and construction industries. Key industry branches include iron and steel, chemical and petrochemical, cement, aluminium, and pulp and paper. Use by industries for the transformation of energy into another form or for the production of fuels is excluded and reported separately under other energy sector. There is an exception for fuel transformation in blast furnaces and coke ovens, which are reported within iron and steel. Consumption of fuels for the transport of goods is reported as part of the transport sector, while consumption by off-road vehicles is reported under industry.

International aviation bunkers: Include the deliveries of aviation fuels to aircraft for international aviation. Fuel used by airlines for their road vehicles are excluded. The domestic/international split is determined on the basis of departure and landing locations and not by the nationality of the airline. For many countries this incorrectly excludes fuels used by domestically owned carriers for their international departures.

International marine bunkers: Include the quantities delivered to ships of all flags that are engaged in international navigation. The international navigation may take place at sea, on inland lakes and waterways, and in coastal waters. Consumption by ships engaged in domestic navigation is excluded. The domestic/international split is determined on the basis of port of departure and port of arrival, and not by the flag or nationality of the ship. Consumption by fishing vessels and by military forces is excluded and instead included in the residential, services and agriculture category.

Investment: Investment is the capital expenditure in energy supply, infrastructure, end-use and efficiency. Fuel supply investment includes the production, transformation and transport of oil, gas, coal and low-emissions fuels. *Power sector* investment includes new construction and refurbishment of generation, electricity grids (transmission, distribution and public electric vehicle chargers), and battery storage. *Energy efficiency* investment includes efficiency improvements in buildings, industry and transport. *Other end-use* investment includes the purchase of equipment for the direct use of renewables, electric vehicles, electrification in buildings, industry and international marine transport, equipment for the use of low-emissions fuels, and CCUS in industry and direct air capture. Data and projections reflect spending over the lifetime of projects and are presented in real terms in year-2022 US dollars converted at market exchange rates unless otherwise stated. Total investment reported for a year reflects the amount spent in that year.

Levelised cost of electricity (LCOE): LCOE combines into a single metric all the cost elements directly associated with a given power technology, including construction, financing, fuel, maintenance and costs associated with a carbon price. It does not include network integration or other indirect costs.

Light-duty vehicles (LDVs)**:** Include passenger cars and light commercial vehicles (gross vehicle weight < 3.5 tonnes).

Light industries: Include non-energy-intensive industries: food and tobacco; machinery; mining and quarrying; transportation equipment; textiles; wood harvesting and processing; and construction.

Lignite: A type of coal that is used in the power sector mostly in regions near lignite mines due to its low energy content and typically high moisture levels, which generally make long-distance transport uneconomic. Data on lignite in the *World Energy Outlook* include peat.

Liquid biofuels: Liquid fuels derived from biomass or waste feedstock, e.g. ethanol, biodiesel and biojet fuels. They can be classified as conventional and advanced biofuels according to the combination of feedstock and technologies used to produce them and their respective maturity. Unless otherwise stated, biofuels are expressed in energy-equivalent volumes of gasoline, diesel and kerosene.

Liquid fuels: Include oil, liquid biofuels (expressed in energy-equivalent volumes of gasoline and diesel), synthetic oil and ammonia.

Low-emissions electricity: Includes output from renewable energy technologies, nuclear power, fossil fuels fitted with CCUS, hydrogen and ammonia.

Low-emissions fuels: Include modern bioenergy, low-emissions hydrogen and low-emissions hydrogen-based fuels.

Low-emissions gases: Include biogas, biomethane, low-emissions hydrogen and low-emissions synthetic methane.

Low-emissions hydrogen: Hydrogen that is produced from water using electricity generated by renewables or nuclear, from fossil fuels with minimal associated methane emissions and processed in facilities equipped to avoid CO_2 emissions, e.g. via CCUS with a high capture rate, or derived from bioenergy. In this report, total demand for low-emissions hydrogen is larger than total final consumption of hydrogen because it additionally includes hydrogen inputs to make low-emissions hydrogen-based fuels, biofuels production, power generation, oil refining, and hydrogen produced and consumed onsite in industry.

Low-emissions hydrogen-based fuels: Include ammonia, methanol and other synthetic hydrocarbons (gases and liquids) made from low-emissions hydrogen. Any carbon inputs, e.g. from CO_2, are not from fossil fuels or process emissions.

Low-emissions hydrogen-based liquid fuels: A subset of low-emissions hydrogen-based fuels that includes only ammonia, methanol and synthetic liquid hydrocarbons, such as synthetic kerosene.

Lower heating value: Heat liberated by the complete combustion of a unit of fuel when the water produced is assumed to remain as a vapour and the heat is not recovered.

Marine energy: Represents the mechanical energy derived from tidal movement, wave motion or ocean currents and exploited for electricity generation.

Middle distillates: Include jet fuel, diesel and heating oil.

Mini-grids: Small electric grid systems, not connected to main electricity networks, linking a number of households and/or other consumers.

Modern energy access: Includes household access to a minimum level of electricity (initially equivalent to 250 kilowatt-hours (kWh) annual demand for a rural household and 500 kWh for an urban household); household access to less harmful and more sustainable cooking and heating fuels, and improved/advanced stoves; access that enables productive economic activity; and access for public services.

Modern gaseous bioenergy: See biogases.

Modern liquid bioenergy: Includes biogasoline, biodiesel, biojet kerosene and other liquid biofuels.

Modern renewables: Include all uses of renewable energy with the exception of the traditional use of solid biomass.

Modern solid bioenergy: Includes all solid bioenergy products (see solid bioenergy definition) except the traditional use of biomass. It also includes the use of solid bioenergy in intermediate and advanced improved biomass cook stoves (ISO tier > 1), requiring fuel to be cut in small pieces or often using processed biomass such as pellets.

Natural gas: Includes gas occurring in deposits, whether liquefied or gaseous, consisting mainly of methane. It includes both non-associated gas originating from fields producing hydrocarbons only in gaseous form, and associated gas produced in association with crude oil production as well as methane recovered from coal mines (colliery gas). Natural gas liquids, manufactured gas (produced from municipal or industrial waste, or sewage) and quantities vented or flared are not included. Gas data in cubic metres are expressed on a gross calorific value basis and are measured at 15 °C and at 760 mm Hg (Standard Conditions). Gas data expressed in exajoules are on a net calorific basis. The difference between the net and the gross calorific value is the latent heat of vaporisation of the water vapour produced during combustion of the fuel (for gas the net calorific value is 10% lower than the gross calorific value).

Natural gas liquids (NGLs): Liquid or liquefied hydrocarbons produced in the manufacture, purification and stabilisation of natural gas. NGLs are portions of natural gas recovered as liquids in separators, field facilities or gas processing plants. NGLs include, but are not limited to, ethane (when it is removed from the natural gas stream), propane, butane, pentane, natural gasoline and condensates.

Near zero emissions capable material production capacity: Capacity that will achieve substantial emissions reductions from the start – but fall short of near zero emissions material production initially (see following definition) – with plans to continue reducing emissions over time such that they could later achieve near zero emissions production without additional capital investment.

Near zero emissions material production: For steel and cement, production that achieves the near zero GHG emissions intensity thresholds as defined in *Achieving Net Zero Heavy Industry Sectors in G7 Members* (IEA, 2022). The thresholds depend on the scrap share of metallic input for steel and the clinker-to-cement ratio for cement. For other energy-intensive commodities such as aluminium, fertilisers and plastics, production that achieves reductions in emissions intensity equivalent to the considerations for near zero emissions steel and cement.

Near zero emissions material production capacity: Capacity that when operational will achieve near zero emissions material production from the start.

Network gases: Include natural gas, biomethane, synthetic methane and hydrogen blended in a gas network.

Non-energy-intensive industries: See other industry.

Non-energy use: The use of fuels as feedstocks for chemical products that are not used in energy applications. Examples of resulting products are lubricants, paraffin waxes, asphalt, bitumen, coal tars and timber preservative oils.

Non-renewable waste: Non-biogenic waste, such as plastics in municipal or industrial waste.

Nuclear power: Refers to the electricity produced by a nuclear reactor, assuming an average conversion efficiency of 33%.

Off-grid systems: Mini-grids and stand-alone systems for individual households or groups of consumers not connected to a main grid.

Offshore wind: Refers to electricity produced by wind turbines that are installed in open water, usually in the ocean.

Oil: Includes both conventional and unconventional oil production. Petroleum products include refinery gas, ethane, liquid petroleum gas, aviation gasoline, motor gasoline, jet fuels, kerosene, gas/diesel oil, heavy fuel oil, naphtha, white spirits, lubricants, bitumen, paraffin, waxes and petroleum coke.

Other energy sector: Covers the use of energy by transformation industries and the energy losses in converting primary energy into a form that can be used in the final consuming sectors. It includes losses in low-emissions hydrogen and hydrogen-based fuels production, bioenergy processing, gas works, petroleum refineries, coal and gas transformation and liquefaction. It also includes energy own use in coal mines, in oil and gas extraction and in electricity and heat production. Transfers and statistical differences are also included in this category. Fuel transformation in blast furnaces and coke ovens are not accounted for in the other energy sector category.

Other industry: A category of industry branches that includes construction, food processing, machinery, mining, textiles, transport equipment, wood processing and remaining industry. It is sometimes referred to as non-energy-intensive industry.

Passenger car: A road motor vehicle, other than a moped or a motorcycle, intended to transport passengers. It includes vans designed and used primarily to transport passengers. Excluded are light commercial vehicles, motor coaches, urban buses and mini-buses/mini-coaches.

Peat: Peat is a combustible soft, porous or compressed, fossil sedimentary deposit of plant origin with high water content (up to 90% in the raw state), easily cut, of light to dark brown colour. Milled peat is included in this category. Peat used for non-energy purposes is not included here.

Plastic collection rate: Proportion of plastics that is collected for recycling relative to the quantity of recyclable waste available.

Plastic waste: Refers to all post-consumer plastic waste with a lifespan of more than one year.

Power generation: Refers to electricity generation and heat production from all sources of electricity, including electricity-only power plants, heat plants, and combined heat and power plants. Both main activity producer plants and small plants that produce fuel for their own use (auto-producers) are included.

Process emissions: CO_2 emissions produced from industrial processes which chemically or physically transform materials. A notable example is cement production, in which CO_2 is emitted when calcium carbonate is transformed into lime, which in turn is used to produce clinker.

Process heat: The use of thermal energy to produce, treat or alter manufactured goods.

Productive uses: Energy used towards an economic purpose: agriculture, industry, services and non-energy use. Some energy demand from the transport sector, e.g. freight, could be considered as productive, but is treated separately.

Rare earth elements (REEs)**:** A group of seventeen chemical elements in the periodic table, specifically the fifteen lanthanides plus scandium and yttrium. REEs are key components in some clean energy technologies, including wind turbines, electric vehicle motors and electrolysers.

Renewables: Include bioenergy, geothermal, hydropower, solar photovoltaics (PV), concentrating solar power (CSP), wind and marine (tide and wave) energy for electricity and heat generation.

Residential: Energy used by households including space heating and cooling, water heating, lighting, appliances, electronic devices and cooking.

Road transport: Includes all road vehicle types (passenger cars, two/three-wheelers, light commercial vehicles, buses and medium and heavy freight trucks).

Self-sufficiency: Corresponds to indigenous production divided by total primary energy demand.

Services: A component of the buildings sector. It represents energy used in commercial facilities, e.g. offices, shops, hotels, restaurants, and in institutional buildings, e.g. schools, hospitals, public offices. Energy use in services includes space heating and cooling, water heating, lighting, appliances, cooking and desalination.

Shale gas: Natural gas contained within a commonly occurring rock classified as shale. Shale formations are characterised by low permeability, with more limited ability of gas to flow through the rock than is the case within a conventional reservoir. Shale gas is generally produced using hydraulic fracturing.

Shipping/navigation: This transport mode includes both domestic and international navigation and their use of marine fuels. Domestic navigation covers the transport of goods or people on inland waterways and for national sea voyages (starts and ends in the same country without any intermediate foreign port). International navigation includes quantities of fuels delivered to merchant ships (including passenger ships) of any nationality for consumption during international voyages transporting goods or passengers.

Single-use plastics (or disposable plastics)**:** Plastic items used only one time before disposal.

Solar: Includes both solar photovoltaics and concentrating solar power.

Solar home systems (SHS)**:** Small-scale photovoltaic and battery stand-alone systems, i.e. with capacity higher than 10 watt peak (Wp) supplying electricity for single households or small businesses. They are most often used off-grid, but also where grid supply is not reliable. Access to electricity in the IEA definition considers solar home systems from 25 Wp in rural areas and 50 Wp in urban areas. It excludes smaller solar lighting systems, e.g. solar lanterns of less than 11 Wp.

Solar photovoltaics (PV)**:** Electricity produced from solar photovoltaic cells including utility-scale and small-scale installations.

Solid bioenergy: Includes charcoal, fuelwood, dung, agricultural residues, wood waste and other solid biogenic wastes.

Solid fuels: Include coal, modern solid bioenergy, traditional use of biomass and industrial and municipal wastes.

Stand-alone systems: Small-scale autonomous electricity supply for households or small businesses. They are generally used off-grid, but also where grid supply is not reliable. Stand-alone systems include solar home systems, small wind or hydro generators, diesel or gasoline generators. The difference compared with mini-grids is in scale and that stand-alone systems do not have a distribution network serving multiple costumers.

Steam coal: A type of coal that is mainly used for heat production or steam-raising in power plants and, to a lesser extent, in industry. Typically, steam coal is not of sufficient quality for steel making. Coal of this quality is also commonly known as thermal coal.

Synthetic methane: Methane from sources other than natural gas, including coal-to-gas and low-emissions synthetic methane.

Synthetic oil: Synthetic oil produced through Fischer-Tropsch conversion or methanol synthesis. It includes oil products from CTL and GTL, and non-ammonia low-emissions liquid hydrogen-based fuels.

Tight oil: Oil produced from shale or other very low permeability formations, generally using hydraulic fracturing. This is also sometimes referred to as light tight oil. Tight oil includes tight crude oil and condensate production except for the United States, which includes tight crude oil only (US tight condensate volumes are included in natural gas liquids).

Total energy supply (TES)**:** Represents domestic demand only and is broken down into electricity and heat generation, other energy sector and total final consumption.

Total final consumption (TFC)**:** Is the sum of consumption by the various end-use sectors. TFC is broken down into energy demand in the following sectors: industry (including manufacturing, mining, chemicals production, blast furnaces and coke ovens); transport; buildings (including residential and services); and other (including agriculture and other non-energy use). It excludes international marine and aviation bunkers, except at world level where it is included in the transport sector.

Total final energy consumption (TFEC)**:** Is a variable defined primarily for tracking progress towards target 7.2 of the United Nations Sustainable Development Goals (SDG). It incorporates total final consumption by end-use sectors, but excludes non-energy use. It excludes international marine and aviation bunkers, except at world level. Typically this is used in the context of calculating the renewable energy share in total final energy consumption (indicator SDG 7.2.1), where TFEC is the denominator.

Traditional use of biomass: Refers to the use of solid biomass with basic technologies, such as a three-stone fire or basic improved cook stoves (ISO tier 0-1), often with no or poorly operating chimneys. Forms of biomass used include wood, wood waste, charcoal agricultural residues and other bio-sourced fuels such as animal dung.

Transport: Fuels and electricity used in the transport of goods or people within the national territory irrespective of the economic sector within which the activity occurs. This includes: fuel and electricity delivered to vehicles using public roads or for use in rail vehicles; fuel delivered to vessels for domestic navigation; fuel delivered to aircraft for domestic aviation; and energy consumed in the delivery of fuels through pipelines. Fuel delivered to international marine and aviation bunkers is presented only at the world level and is excluded from the transport sector at a domestic level.

Trucks: Includes all size categories of commercial vehicles: light trucks (gross vehicle weight < 3.5 tonnes); medium freight trucks (gross vehicle weight 3.5-15 tonnes); and heavy freight trucks (gross vehicle weight > 15 tonnes).

Unabated fossil fuel use: Consumption of fossil fuels in facilities without CCUS.

Useful energy: Refers to the energy that is available to end-users to satisfy their needs. This is also referred to as energy services demand. As result of transformation losses at the point of use, the amount of useful energy is lower than the corresponding final energy demand for most technologies. Equipment using electricity often has higher conversion efficiency than equipment using other fuels, meaning that for a unit of energy consumed, electricity can provide more energy services.

Value-adjusted levelised cost of electricity (VALCOE)**:** Incorporates information on both costs and the value provided to the system. Based on the LCOE, estimates of energy, capacity and flexibility value are incorporated to provide a more complete metric of competitiveness for power generation technologies.

Variable renewable energy (VRE)**:** Refers to technologies whose maximum output at any time depends on the availability of fluctuating renewable energy resources. VRE includes a broad array of technologies such as wind power, solar PV, run-of-river hydro, concentrating solar power (where no thermal storage is included) and marine (tidal and wave).

Zero carbon-ready buildings: A zero carbon-ready building is highly energy efficient and either uses renewable energy directly or an energy supply that can be fully decarbonised, such as electricity or district heat.

Zero emissions vehicles (ZEVs)**:** Vehicles that are capable of operating without tailpipe CO_2 emissions (battery electric and fuel cell vehicles).

Regional and country groupings

Advanced economies: OECD regional grouping and Bulgaria, Croatia, Cyprus[1,2], Malta and Romania.

Africa: North Africa and sub-Saharan Africa regional groupings.

Asia Pacific: Southeast Asia regional grouping and Australia, Bangladesh, Democratic People's Republic of Korea (North Korea), India, Japan, Korea, Mongolia, Nepal, New Zealand, Pakistan, The People's Republic of China (China), Sri Lanka, Chinese Taipei, and other Asia Pacific countries and territories.[3]

Caspian: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

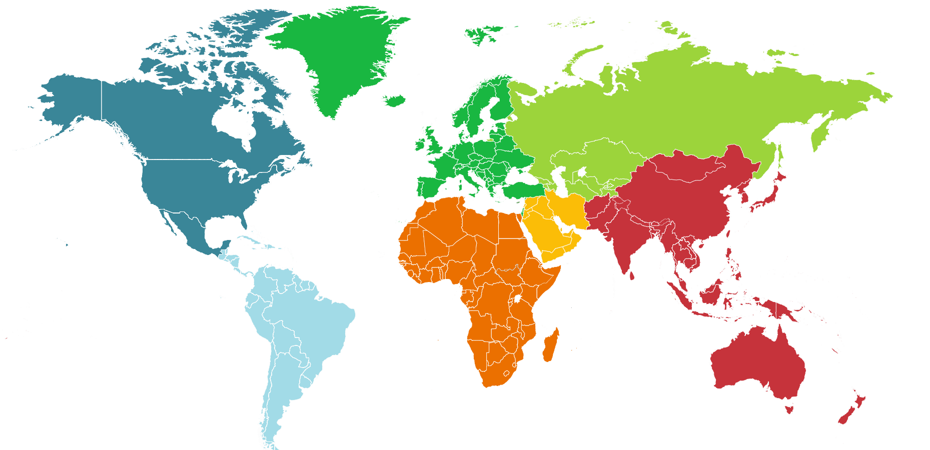
Central and South America: Argentina, Plurinational State of Bolivia (Bolivia), Bolivarian Republic of Venezuela (Venezuela), Brazil, Chile, Colombia, Costa Rica, Cuba, Curaçao, Dominican Republic, Ecuador, El Salvador, Guatemala, Guyana, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Suriname, Trinidad and Tobago, Uruguay and other Central and South American countries and territories.[4]

China: Includes (The People's Republic of) China and Hong Kong, China.

Developing Asia: Asia Pacific regional grouping excluding Australia, Japan, Korea and New Zealand.

Emerging market and developing economies: All other countries not included in the advanced economies regional grouping.

Figure C.1 ▷ Main country groupings



Note: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Eurasia: Caspian regional grouping and the Russian Federation (Russia).

Europe: European Union regional grouping and Albania, Belarus, Bosnia and Herzegovina, Gibraltar, Iceland, Israel[5], Kosovo, Montenegro, North Macedonia, Norway, Republic of Moldova, Serbia, Switzerland, Türkiye, Ukraine and United Kingdom.

European Union: Austria, Belgium, Bulgaria, Croatia, Cyprus[1,2], Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovak Republic, Slovenia, Spain and Sweden.

IEA (International Energy Agency)**:** OECD regional grouping excluding Chile, Colombia, Costa Rica, Iceland, Israel, Latvia and Slovenia.

Latin America and the Caribbean (LAC)**:** Central and South America regional grouping and Mexico.

Middle East: Bahrain, Islamic Republic of Iran (Iran), Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic (Syria), United Arab Emirates and Yemen.

Non-OECD: All other countries not included in the OECD regional grouping.

Non-OPEC: All other countries not included in the OPEC regional grouping.

North Africa: Algeria, Egypt, Libya, Morocco and Tunisia.

North America: Canada, Mexico and United States.

OECD (Organisation for Economic Co-operation and Development): Australia, Austria, Belgium, Canada, Chile, Colombia, Costa Rica, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Korea, Latvia, Lithuania, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Türkiye, United Kingdom and United States.

OPEC (Organization of the Petroleum Exporting Countries): Algeria, Angola, Bolivarian Republic of Venezuela (Venezuela), Equatorial Guinea, Gabon, Iraq, Islamic Republic of Iran (Iran), Kuwait, Libya, Nigeria, Republic of the Congo (Congo), Saudi Arabia and United Arab Emirates.

OPEC+: OPEC grouping plus Azerbaijan, Bahrain, Brunei Darussalam, Kazakhstan, Malaysia, Mexico, Oman, Russian Federation (Russia), South Sudan and Sudan.

Southeast Asia: Brunei Darussalam, Cambodia, Indonesia, Lao People's Democratic Republic (Lao PDR), Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam. These countries are all members of the Association of Southeast Asian Nations (ASEAN).

Sub-Saharan Africa: Angola, Benin, Botswana, Cameroon, Côte d'Ivoire, Democratic Republic of the Congo, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Kingdom of Eswatini, Madagascar, Mauritius, Mozambique, Namibia, Niger, Nigeria, Republic of the Congo (Congo), Rwanda, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania (Tanzania), Togo, Uganda, Zambia, Zimbabwe and other African countries and territories.[6]

Country notes

[1] Note by Republic of Türkiye: The information in this document with reference to "Cyprus" relates to the southern part of the island. There is no single authority representing both Turkish and Greek Cypriot people on the island. Türkiye recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Türkiye shall preserve its position concerning the "Cyprus issue".

[2] Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Türkiye. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

[3] Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste, Tonga and Vanuatu.

[4] Individual data are not available and are estimated in aggregate for: Anguilla, Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, Bonaire, Sint Eustatius and Saba, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), Grenada, Montserrat, Saint Kitts and Nevis, Saint Lucia, Saint Pierre and Miquelon, Saint Vincent and Grenadines, Saint Maarten (Dutch part), Turks and Caicos Islands.

[5] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

[6] Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cabo Verde, Central African Republic, Chad, Comoros, Djibouti, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Malawi, Mali, Mauritania, Sao Tome and Principe, Seychelles, Sierra Leone and Somalia.

Abbreviations and acronyms

AC	alternating current
AFOLU	agriculture, forestry and other land use
APEC	Asia-Pacific Economic Cooperation
APS	Announced Pledges Scenario
ASEAN	Association of Southeast Asian Nations
BECCS	bioenergy equipped with CCUS
BEV	battery electric vehicles
CAAGR	compound average annual growth rate
CAFE	corporate average fuel economy standards (United States)
CBM	coalbed methane
CCGT	combined-cycle gas turbine
CCUS	carbon capture, utilisation and storage
CDR	carbon dioxide removal
CEM	Clean Energy Ministerial
CH_4	methane
CHP	combined heat and power; the term co-generation is sometimes used
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CO_2-eq	carbon-dioxide equivalent
COP	Conference of Parties (UNFCCC)
CSP	concentrating solar power
CTG	coal-to-gas
CTL	coal-to-liquids
DAC	direct air capture
DACS	direct air capture and storage
DC	direct current
DER	distributed energy resources
DFI	development finance institutions
DRI	direct reduced iron
DSI	demand-side integration
DSO	distribution system operator
DSR	demand-side response
EHOB	extra-heavy oil and bitumen
EMDE	emerging market and developing economies
EOR	enhanced oil recovery
EPA	Environmental Protection Agency (United States)
ESG	environmental, social and governance
ETS	emissions trading system
EU	European Union
EU ETS	European Union Emissions Trading System
EV	electric vehicle

FAO	Food and Agriculture Organization of the United Nations
FCEV	fuel cell electric vehicle
FDI	foreign direct investment
FID	final investment decision
FiT	feed-in tariff
FOB	free on board
GEC	Global Energy and Climate (model)
GDP	gross domestic product
GHG	greenhouse gases
GTL	gas-to-liquids
H_2	hydrogen
HDV	heavy-duty vehicle
HEFA	hydrogenated esters and fatty acids
HFO	heavy fuel oil
HVDC	high voltage direct current
IAEA	International Atomic Energy Agency
ICE	internal combustion engine
ICT	information and communication technologies
IEA	International Energy Agency
IGCC	integrated gasification combined-cycle
IIASA	International Institute for Applied Systems Analysis
IMF	International Monetary Fund
IMO	International Maritime Organization
IOC	international oil company
IPCC	Intergovernmental Panel on Climate Change
IPT	independent power transmission
LCOE	levelised cost of electricity
LCV	light commercial vehicle
LDV	light-duty vehicle
LED	light-emitting diode
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LULUCF	land use, land-use change and forestry
MEPS	minimum energy performance standards
MER	market exchange rate
NDC	Nationally Determined Contribution
NEA	Nuclear Energy Agency (an agency within the OECD)
NGLs	natural gas liquids
NGV	natural gas vehicle
NOC	national oil company
NPV	net present value
NO_X	nitrogen oxides
N_2O	nitrous oxide
NZE	Net Zero Emissions by 2050 Scenario

OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
PHEV	plug-in hybrid electric vehicles
PLDV	passenger light-duty vehicle
PM	particulate matter
$PM_{2.5}$	fine particulate matter
PPA	power purchase agreement
PPP	purchasing power parity
PV	photovoltaics
R&D	research and development
RD&D	research, development and demonstration
SAF	sustainable aviation fuel
SDG	Sustainable Development Goals (United Nations)
SHS	solar home systems
SME	small and medium enterprises
SO_2	sulphur dioxide
STEPS	Stated Policies Scenario
T&D	transmission and distribution
TES	total energy supply
TFC	total final consumption
TFEC	total final energy consumption
TPA	tonne per annum
TPED	total primary energy demand
TSO	transmission system operator
UAE	United Arab Emirates
UN	United Nations
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
US	United States
USGS	United States Geological Survey
VALCOE	value-adjusted levelised cost of electricity
VRE	variable renewable energy
WACC	weighted average cost of capital
WEO	World Energy Outlook
WHO	World Health Organization
ZEV	zero emissions vehicle
ZCRB	zero carbon-ready building

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Typeset in France by IEA - November 2023
Cover design: IEA
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The Oil and Gas Industry in Net Zero Transitions

World Energy Outlook Special Report

The global oil and gas industry encompasses a large and diverse range of players: from small, specialised operators to huge national oil companies. These producers face pivotal choices about their role in the global energy system amid a worsening climate crisis fuelled in large part by their core products.

The Oil and Gas Industry in Net Zero Transitions analyses the implications and opportunities for the industry that would arise from stronger international efforts to reach energy and climate targets.

It also examines how transitions increase the likelihood of boom and bust cycles for oil and gas producer economies. It highlights strategies for producer economies that could complement broader reforms to build macroeconomic stability and the role of international partners to support this process.

The report sets out a fair and feasible way forward in which oil and gas companies and producer economies take a real stake in the clean energy economy while helping the world avoid the most severe impacts of climate change.