DNV·GL

ENERGY TRANSITION OUTLOOK 2020
OIL AND GAS

A global and regional forecast to 2050

SAFER, SMARTER, GREENER

FOREWORD

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Transforming the oil and gas industry. Who's first?

Rapid electrification of energy and growth in renewables will significantly reduce emissions in the coming decades, but fossil fuels will still be needed to supply half of the world's energy in 2050, according to our 2020 Energy Transition Outlook. Where there is demand for oil and gas, there will be a future for the oil and gas industry. The question is what type of future that will be. Without greater efforts to decarbonize, our forecasts show a future in which the world misses the 2°C limit for global warming under the Paris Agreement.

Pressure is mounting on the oil and gas sector to address the climate change crisis, and this is coming from all sides: from society and governments, from investors, and also from people within the industry. We see the sector increasingly putting the energy transition at the centre of its agenda, but climate change and ambitions to reduce it are outpacing action. Our forecasts show that world emissions will remain stubbornly high until the mid-2030s and that deep decarbonization of the world's energy system is still 15 years away.

> “The oil and gas industry needs to prepare for an energy system that does not accept the release of carbon emissions.

The technologies needed to accelerate the energy transition are available today, but they need to scale, and sooner.

On one side, the world has started down the path to much greater use of renewables and battery storage, which will enable further electrification of sectors such as transport, manufacturing and heat in the home. On the other side, natural gas will still be the world's largest energy source at mid-century, and technologies to decarbonize it are yet to take off.

We forecast that hydrogen and carbon capture and storage (CCS) will be a catalyst for deep decarbonization after 2035, removing carbon from natural gas – before or after combustion – to reach hard-to-abate sectors. This could transform the oil and gas industry into the decarbonizer of hydrocarbons and the world's supplier of carbon capture and storage. It could transform the sector so that it is an essential contributor to realizing climate ambitions, rather than to missing them.

The problem is that CCS won't move down the cost learning curve unless the industry significantly increases its roll-out of the technology, but we don't foresee this happening until the costs have come down or a carbon price exceeds the cost of the technology. Hydrogen faces a similar issue. It relies on CCS for blue hydrogen, and on the cost of electrolyzers falling to produce green hydrogen at scale. We forecast that both will happen in order to realize the hydrogen economy, just not until the 2040s.

> “Someone needs to go first: if a major country or region sets a carbon price high enough to make large-scale CCS a reality, others will follow.

Decarbonized and green gasses would have a bright future following such a transformation, with hydrogen and CCS complementing renewable electricity, battery technology and alternative low-carbon fuels to provide societies with a secure, affordable supply of clean energy.

Forming partnerships among government, industry, and associations will be crucial in scaling innovation and technologies for decarbonization. Working together to make hydrogen and CCS safe, effective, and commercially viable will give the oil and gas industry the certainty it needs to manage new risks and accelerate its transformation towards a low-carbon future.

We encourage all stakeholders to help shift the mindset and the timeline, from preparing for deep decarbonization in the coming decades to starting to realize it today. Someone needs to go first, and there really is no time to lose.

Liv A. Hovem

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EXECUTIVE SUMMARY

Our 2020 *Energy Transition Outlook* (ETO) forecasts a decarbonizing world in which energy demand plateaus, renewables grow significantly, natural gas becomes the world's largest energy source, and oil demand never again reaches the levels of 2019.

MULTIPLE TRANSITIONS AS GROWTH IN WORLD ENERGY DEMAND SLOWS

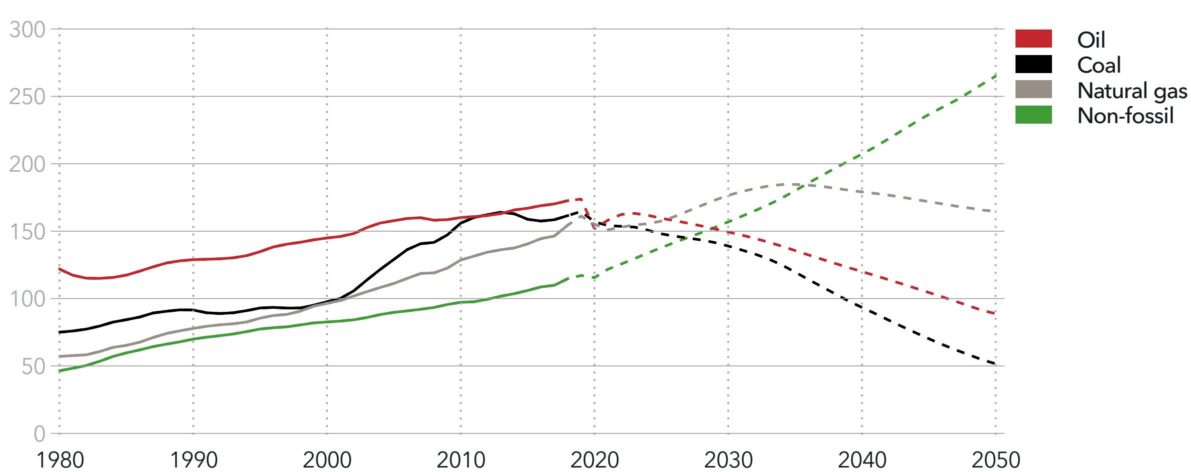
World final energy demand will remain relatively flat throughout our forecast period to 2050. It has risen by around 30% over the past 15 years, but in the next 15 years – in the lead up to peak energy demand in the mid-2030s – it will increase by only 3%. It will be held back by slower growth in productivity and global population, and continuous increases in energy efficiency, particularly in transport.

In recent years, renewables have helped to meet increasing energy demand, while use of fossil fuels has grown at a slower pace. Now, with relatively flat energy demand in the coming decades, this is set to change. In 2018 (the benchmark year in this report), 81% of the world's energy is supplied by fossil fuels and 19% by non-fossil fuels. By 2050, fossil fuels will account for 54% of primary energy supply, while non-fossil fuels will make up 46% of the mix. However, the outlook is not the same for all fossil fuels. The supply of coal and oil are set to follow downward trajectories and will in 2050

FIGURE 0.1

World primary energy supply by source

Units: EJ/yr



Historical data source: IEA WEB (2019)

represent only 9% and 16% of primary energy supply, respectively. Natural gas, however, will see its share of primary energy supply grow modestly from 26% in 2018 to 29% in 2050, partly as it displaces the use of coal (Figure 0.1).

Crucially, we will not see one energy transition to 2050, but several, each interrelated and playing out differently around the world. These include transitions from fossil fuels to renewables, from coal and oil to natural gas, and from fossil fuels to decarbonized gas.

COST TO WIN IN A DECLINING OIL MARKET

Oil demand is set to never fully recover from the COVID-19-induced market shock in 2020. Our Outlook forecasts that global crude primary oil demand will fall 13% in 2020, reaching a level not seen since the early 2000s. It will rebound somewhat to 2023, before declining gradually to half of its 2018 level in real terms by 2050. However, while oil demand will decline rapidly in some regions, it will continue to grow in others. Continued investment in oil and gas will be needed throughout our forecast period to maintain production at levels required to meet global demand, even in a declining market.

Declines in oil will be led by the transport sector, which will remain the largest source of oil demand, even though this declines rapidly from the mid-2020s. The decrease will be led first by the electrification of passenger vehicles, then by natural gas, decarbonized and green gas, and biofuel increasingly supplying the energy for ships, larger road vehicles, and aviation toward mid-century.

Middle East and North Africa, North East Eurasia, and North America are set to dominate oil production over the next three decades. These three regions will together account for 90% of oil supply in 2050 and be the only net exporting regions. Their dominance will be caused by a shift from producing 'more oil' to 'cheapest oil', as onshore oil from Middle East and North Africa wins on cost, followed by North East Eurasia. This will put increasing pressure on unconventional onshore and offshore oil production to 2050.

NATURAL GAS TO BECOME WORLD'S LARGEST ENERGY SOURCE

As the least carbon-intensive fossil fuel, natural gas will play a prominent role in the energy transition, taking its place as the world's largest energy source from the mid-2020s. Global gas demand will peak around a decade later.

Greater China and the Indian Subcontinent will produce only a fraction of the gas they consume, with these regions accounting for more than 75% of natural gas imports from 2035. To keep up, gas will see significant increases in interregional trade. A quarter of world gas demand will be traded between regions by 2035, much of this coming in the form of liquefied natural gas (LNG) exports, which will more than double over the forecast period.

As with oil production, North America, Middle East and North Africa, and North East Eurasia are set to dominate natural gas production, accounting for around 75% of the world's supply throughout the forecast period. These three regions will see strong ongoing domestic demand for gas, but will also supply much of the growing exports. When compared with the forecast for oil production during the period, we see that offshore gas production will stay more competitive. This is partly due to continued strong demand for gas, bringing more certainty that investments with longer horizons will make a return on investment, and partly due to the price advantage of regional supply by (offshore) pipelines over LNG imports, particularly in regions with well-developed gas infrastructure.

Liquefaction capacity is set to triple over next decade, led by North America as the region accounts for three fifths of a projected LNG capex spike in the mid-2020s. Middle East and North Africa (Qatar in particular) and OECD Pacific (Australia in particular) will make up much of the rest of LNG exports. North East Eurasia will supply Europe and Asia with natural gas, but largely via pipelines.

THE ENERGY TRANSITION IS NOWHERE NEAR FAST ENOUGH TO DELIVER ON THE PARIS AGREEMENT

The energy transition we forecast will not deliver on the COP 21 Paris Agreement – an international framework to reduce greenhouse gas emissions. This aims to keep global warming to 'well below 2°C' and pledges to pursue efforts to limit the increase to 1.5°C. We forecast that the 1.5°C carbon budget will be exhausted in 2028 and the 2°C budget in 2051. Extrapolating the emission trends, our Outlook points to a 2.3°C warming of the planet by 2100, compared with the pre-industrial level.

This comes as we forecast CO_2 emissions to remain stubbornly high until the mid-2030s, falling just 15% in the next 15 years, before then dropping 40% in the 15 years to 2050. Contributors to the fall in carbon emissions from the middle of the next decade will include the scaling of decarbonization of natural gas, and enhanced use of green gas produced using renewable sources.

PRESSURE TO DECARBONIZE THE OIL AND GAS INDUSTRY

Growing awareness of the urgency and magnitude of the climate change challenge is increasing pressure on the oil and gas industry to decarbonize. Several oil and gas majors are transforming themselves into broad-portfolio energy companies, with interests in a diverse range of sources, carriers, and distribution models. They are shifting from 'big oil' to 'big energy'. The longer-term success of the sector may hinge on its ability to proactively drive the necessary transition rather than passively react to societal pressure.

Based on the commitments made by oil and gas companies so far, we expect emissions reductions from oil and gas production to dominate the industry's decarbonization agenda in the shorter term. Key solutions include electrifying offshore platforms and oil and gas assets, reducing flaring and venting, increased efforts to detect and stem methane leaks, and efficiency gains through digitalization of the oil and gas value chain.

TRANSITION TO DECARBONIZED AND GREEN GAS FROM THE MID-2030s

Primary energy demand for natural gas will decline from the mid-2030s, according to our forecast. From this point, three significant things happen. First, the amount of natural gas used for power generation starts to fall as renewables scale significantly and electricity is increasingly used to replace natural gas in sectors where it is feasible to do so. Second, natural gas will be partially decarbonized through

DECARBONIZED GAS VS GREEN GAS

While there are limited options to reduce emissions from oil consumption, natural gas consumption can more easily be decarbonized through deploying CCS technology. Decarbonized gas is produced either by removing carbon from natural gas before combustion, to produce hydrogen, or at the point of end-user combustion at sources of significant emissions, such as powerplants and in industry. Decarbonized gas is distinct from what this report calls green gas, which principally covers biogas and hydrogen produced from renewable sources.

gas reforming with carbon capture and storage (CCS) to produce 'blue' hydrogen, with us predicting rapid growth in this area towards the end of our forecast period. Third, hydrogen produced from renewables, 'green' hydrogen, will join decarbonized gas in replacing some of the final demand for natural gas, largely in hard-to-abate sectors such as steel, cement, aluminium and glassmaking.

Our forecast projects that 13% of gas will be decarbonized in 2050. This follows rapid growth in production of hydrogen from natural gas, and of natural gas with CCS in power and industry, towards the end of our forecast period. In terms of lowering the emissions of natural gas consumption, we project that hydrogen (produced from fossil fuels with CCS and from renewables via electrolysis) will supply 23% of end-user demand for gas (natural gas and hydrogen). Around half of this hydrogen will be produced from fossil fuels in 2050, with around 70% coming from natural gas. The other half will be produced from electricity from predominantly renewable sources. Both the decarbonization of natural gas through CCS and the use of hydrogen as a vector to reduce emissions from natural gas consumption will be led by Europe, Greater China, North America, and OECD Pacific.

In the context of the Paris Agreement, we see that the transition to decarbonized and green gas, with related scaling of CCS and hydrogen, will not be quick enough: we forecast that CCS and hydrogen will not begin to scale for another 15 years. While technology to scale decarbonized and green gas is available and viable, the policy framework to scale it is only just taking shape (see Section 3.4), and only in some regions. As was the case with solar and wind technologies in the 2010s, the quicker that government incentivizes industry to adopt these technologies, the quicker the technology progresses along the cost-learning curve and becomes independently financially viable. In line with this, policy support for hydrogen, CCS technology, and solutions for hard-to-abate sectors needs urgent acceleration if regions, and the world, are to meet emissions targets.

POLICY IS KEY TO DECARBONIZATION

Public energy policies – at regional, national, and local level – are key, not just in setting out the path for regions and the world to decarbonize, but also in deciding how quickly they head down that path. They are led by political priorities to ensure a secure, affordable supply of decarbonized energy – the 'energy trilemma'. These policies are influenced by the energy resources available and by societal pressures, including rising concern over climate change and calls for cleaner energy.

Many policies, from the Paris Agreement to the local level, are supporting transitions to cleaner energy. Some of these will affect demand for existing oil and gas products and drive companies to reduce their carbon footprint; others may completely transform the oil and gas industry.

Net-zero targets in Europe have kick-started the region's energy transition and are now extending it to hard-to-abate sectors. Since 2019, the European Union and several countries in Europe have been setting targets for net-zero carbon emissions by 2050. Under these targets, emissions will need to be reduced, while those that remain must be captured or offset. Multiple policy and market mechanisms are in play to deliver the net-zero target in Europe. Among them, we see a price on carbon emissions reaching levels that allow CCS to scale – which will subsequently lower the cost of the technology in other regions. The EU is also considering a 'CO_2 border tax', which would extend a price on carbon to imported products. The aim is to prevent stakeholders from exporting their carbon emissions, such as by moving production out of the region.

Greater China's emissions reduction trajectory is also vital to the global energy transition. From 2030, the region will account for more than half the world's net emission reductions. This will be driven by strong policy support in China – in the form of direct intervention – for natural gas alongside investment in renewables, and later to drive the scaling of CCS and hydrogen in the 2040s.

In North America, a patchwork of policy targets and incentives, at state and federal level, will drive decarbonization through increases in renewables and electrification, and by lowering the carbon intensity of fuels. The region is also investing in and incentivizing uptake of CCS and to a lesser degree hydrogen, though policies are not set to address emissions throughout the oil and gas value chain, including consumption, to the same degree as in Europe.

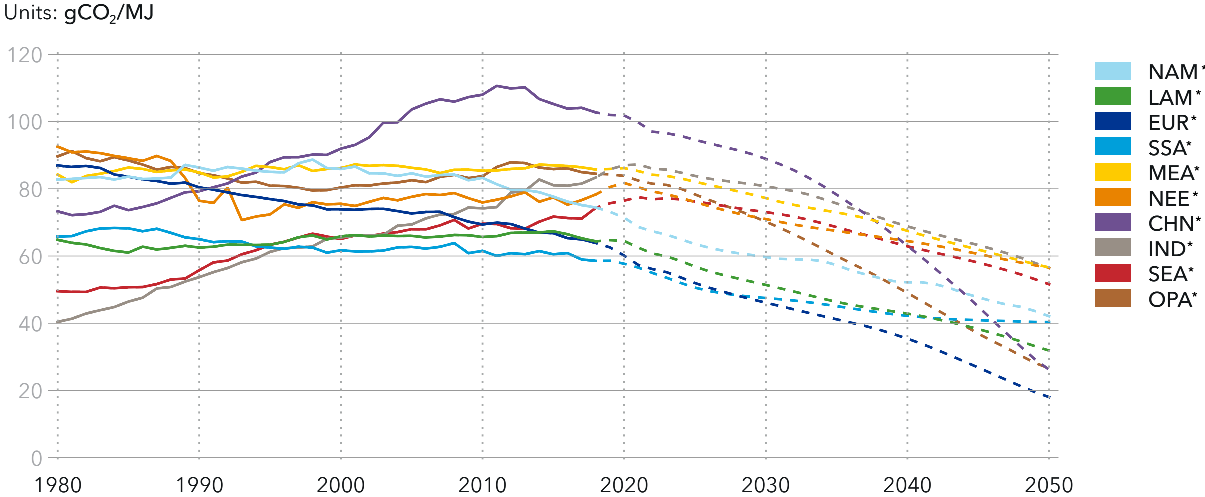
All regions are balancing decarbonization with the need to ensure an increasing supply of secure, affordable energy. However, some also have the challenge of providing energy to increasingly energy-hungry economies and populations. Emissions will not decline during the forecast period on the Indian Subcontinent or in South East Asia and Sub-Saharan Africa. Policies in these regions will largely focus on the transition from coal to natural gas, growth in renewables and electrification, ensuring increased energy independence, and meeting pressure to curb local pollution.

Emissions intensity (energy-related CO_2 emissions / energy demand) is set to remain high in the regions and countries that will supply the world's oil and gas – predominantly where the cost of production is lowest or can be easily scaled up and down. This is linked to domestic reliance on fossil-fuel jobs and revenues, as well as the ease and financial benefits (at least in the shorter term) of continuing to use fossil fuels in these regions.

FIGURE 0.2

Emission intensity of final energy demand by region

Units: gCO_2/MJ



*For more information about the world regions covered by our forecast, see Section 1.1

A BRIGHT FUTURE FOR GAS REQUIRES QUICKER TRANSFORMATION OF THE OIL AND GAS INDUSTRY

Net-zero policies in Europe, China's direct interventions, and incentives in North America are policies that create the impetus to begin scaling clean production of hydrogen and other low-carbon fuels, and will propel recognition that scaling CCS will be essential to meet the targets set under the Paris Agreement. Ultimately, these policies could transform the oil and gas industry into the decarbonizer of hydrocarbons and the world's carbon waste disposal agent. Gas – decarbonized and green – would have a bright future following such a transformation, as it complements renewable electricity to provide societies with a secure, affordable, supply of clean energy.

The mid-2030s is currently the point at which we forecast that decarbonization policies will begin to act as a catalyst for the transformation of the oil and gas industry – with the scaling of CCS and hydrogen. This transformation only really takes hold in the 2040s, and only in some regions. The decarbonization of gas and moves to green gas help to significantly reduce emissions in our forecast, but come too late to have much of an impact on meeting the Paris Agreement targets. As pressure mounts to decarbonize, such a delay may challenge the oil and gas industry's license to operate in some regions.

CHAPTER 1

INTRODUCTION

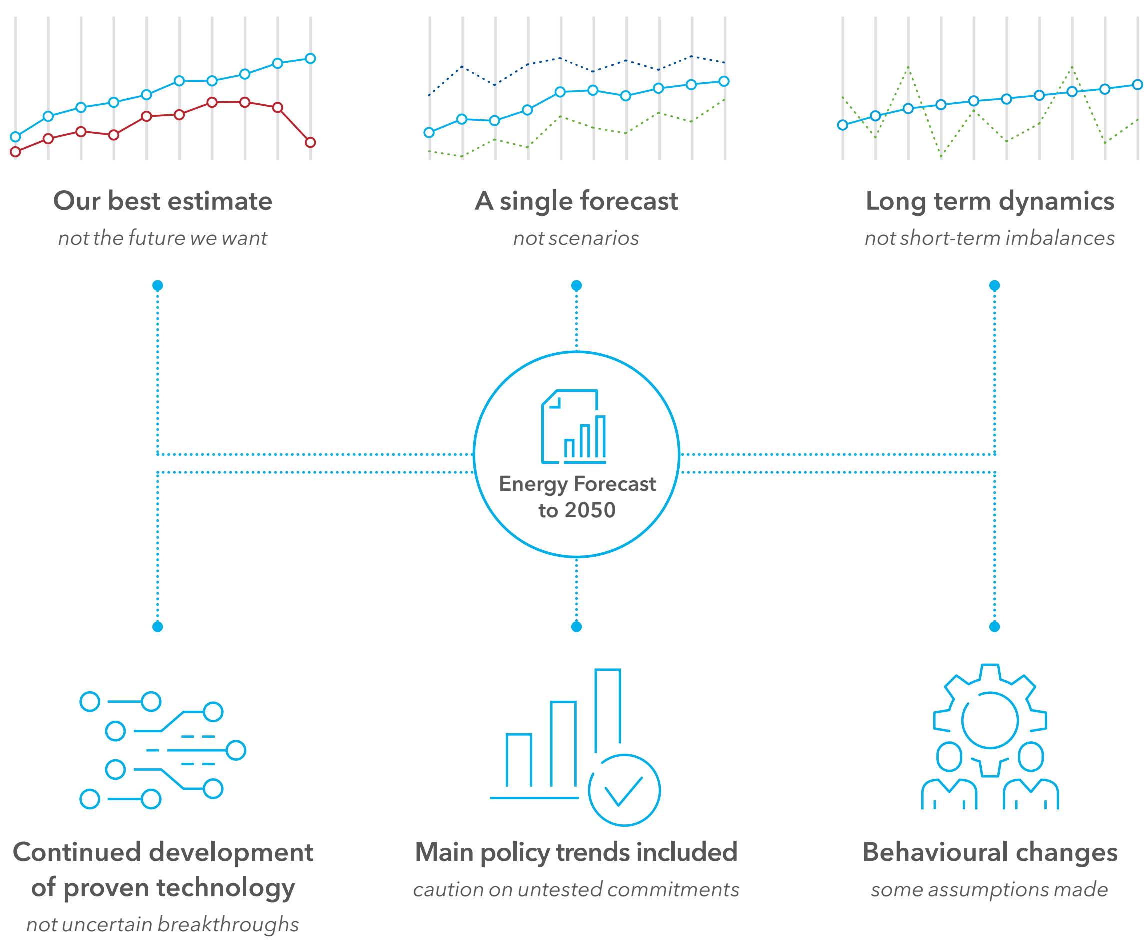
1 INDEPENDENT WORLD ENERGY FORECAST TO 2050

1.1 BEST ESTIMATE OF A SINGLE LIKELY FUTURE

This Outlook provides the independent view of DNV GL on what we consider to be our best estimate for the future of energy demand and supply, as the energy transition unfolds to 2050. We forecast a single likely future of the world's energy system through to mid-century, not a range of scenarios.

This publication is one in a suite of *Energy Transition Outlook* (ETO) reports. We also provide a main Outlook report[1] and companion Executive Summary[2] document, as well as reports on the implications for separate industries. These include a report on power supply and use[3], and one on the maritime industry[4], in addition to this report[5] on the oil and gas industry. For full analysis of the sensitivities related to our energy-system modelling, please refer to our main Outlook report.

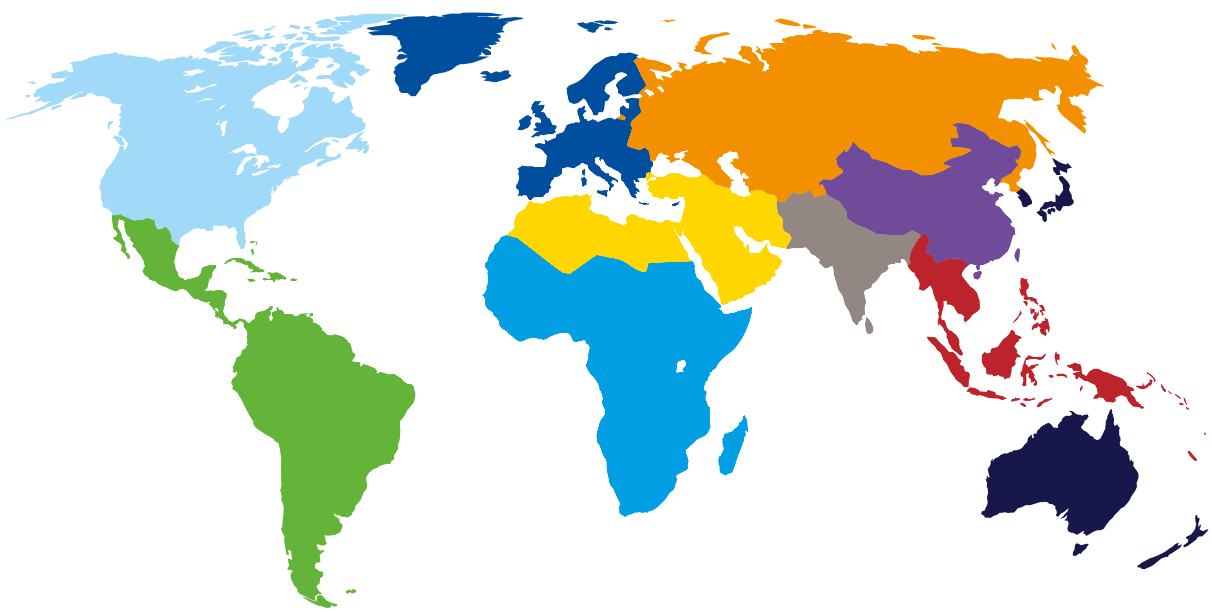
OUR APPROACH



1.1.1 OUTLOOK DIVIDED INTO 10 REGIONS

Our ETO Model divides the world into 10 geographical regions. They are chosen based on geographical location, resource richness, extent of economic development, and energy characteristics. Each region's input and results are the sum of all countries within it. Typically, weighted averages are used: countries with the largest populations, energy use, and so on, are assigned more weight when calculating averages for relevant parameters. Prominent characteristics of certain countries – nuclear dominance in France, for example – are averaged over the entire region.

MAP AND KEY OF OUTLOOK REGIONS



- **North America (NAM)** Canada and the US
- **Latin America (LAM)** all nations from Mexico to the southern tip of South America, and including the Caribbean
- **Europe (EUR)** all European countries including the Baltics. Excludes Russia, all former Soviet Union republics, and Turkey
- **Sub-Saharan Africa (SSA)** all African countries except Algeria, Egypt, Libya, Morocco, and Tunisia
- **Middle East and North Africa (MEA)** from Morocco to Iran. Includes Turkey and the Arabian Peninsula
- **North East Eurasia (NEE)** Russia and neighbouring countries, including all former Soviet Union states except the Baltics. Includes Mongolia and North Korea
- **Greater China (CHN)** Mainland China, Taiwan, Hong Kong and Macau
- **Indian Subcontinent (IND)** India, Pakistan, Bangladesh, Sri Lanka, Afghanistan, Nepal, Bhutan and the Maldives
- **South East Asia (SEA)** From Myanmar to Papua New Guinea. Includes many smaller island states in the Indian and Pacific Oceans
- **OECD Pacific (OPA)** Japan, Republic of Korea ('South Korea'), Australia and New Zealand

1.1.2 MEASURING ENERGY IN OUR OUTLOOK

In this Outlook, we use joules as the main unit for energy, or rather exajoules (EJ) for large quantities associated with national or global production.

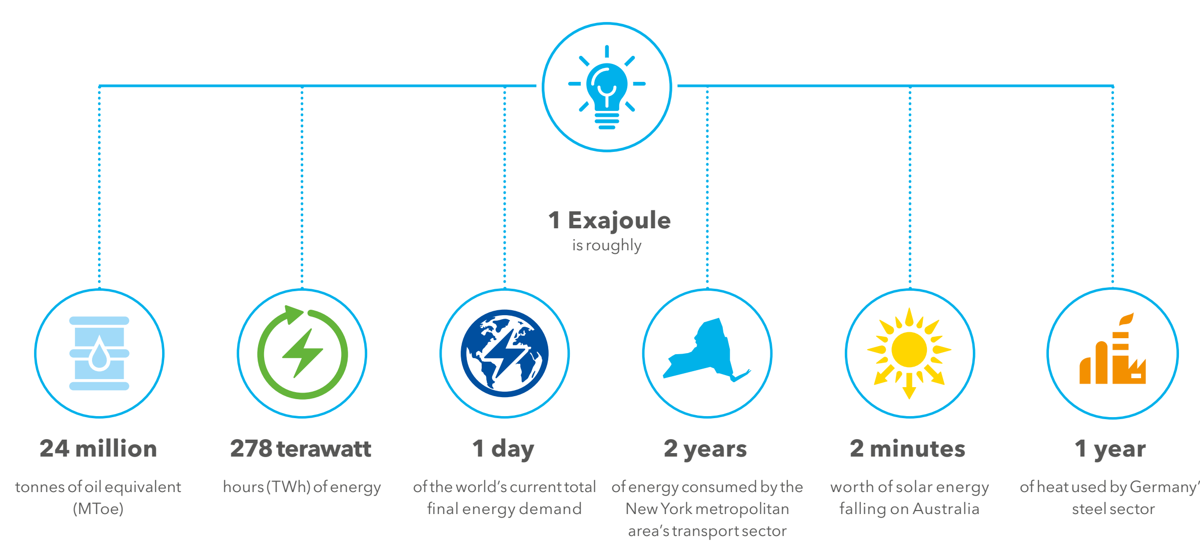
Forecasts for final energy demand and primary energy supply form a substantial part of this Outlook. Final energy demand includes just the energy consumed at the point of end use, excluding energy demand to produce other energy carriers, such as producing electricity or hydrogen from natural gas. When comparing them, it should be borne in mind that primary energy demand is higher than final energy demand. This is because energy is lost in the system between the point of supply and the point of consumption, much of it caused by electricity generation, transmission losses, and thermal inefficiencies.

1.2 PARIS AGREEMENT SETS THE STANDARD

The Paris Agreement has, since 2015, set the stage for decarbonization ambitions globally. The agreement sets out that the world should seek to limit global warming to well below 2°C and to pursue efforts to limit global warming to 1.5°C. It is an international agreement that almost all countries have signed. More than the global commitments mentioned, the Agreement brings a level of accountability down to the national level, requiring signatory states to meet 'nationally determined contributions' (NDCs) in emissions reductions, and to report regularly on their progress. At the industry level, many oil and gas companies have already expressed their support for the goals of the Paris Agreement, and the industry will be increasingly affected by national policies adopted to meet NDCs.

Throughout this report, we measure the pace and depth of decarbonization efforts against compliance with Paris Agreement targets. That is, if we say something will not happen quick enough, or not have a deep enough impact, this is because it will not lead to compliance with the Paris Agreement.

MEASURING ENERGY IN OUR OUTLOOK



CHAPTER 2

DEMAND, SUPPLY, INVESTMENT FORECAST

2 DEMAND, SUPPLY, INVESTMENT FORECAST

We see a world decarbonizing, as energy demand slows, renewables grow, natural gas becomes the world's largest energy source, and oil demand never again reaches the levels of 2019.

2.1 WORLD ENERGY DEMAND SLOWS

World final energy demand was 425 exajoules (EJ) in 2018 (Figure 2.1). This converts to some 10,200 million tonnes of oil equivalent (Mtoe). After a dramatic drop in 2020 to 398 EJ, induced by the effects of COVID-19, world energy demand will grow to a peak of 444 EJ in the mid-2030s. It will then fall to 424 EJ by 2050 – around the same level as in 2018. To place this in context, world energy demand has risen by around 30% in the past 15 years. But, in the next 15 years – in the lead up to peak energy demand – it will increase by only 3%.

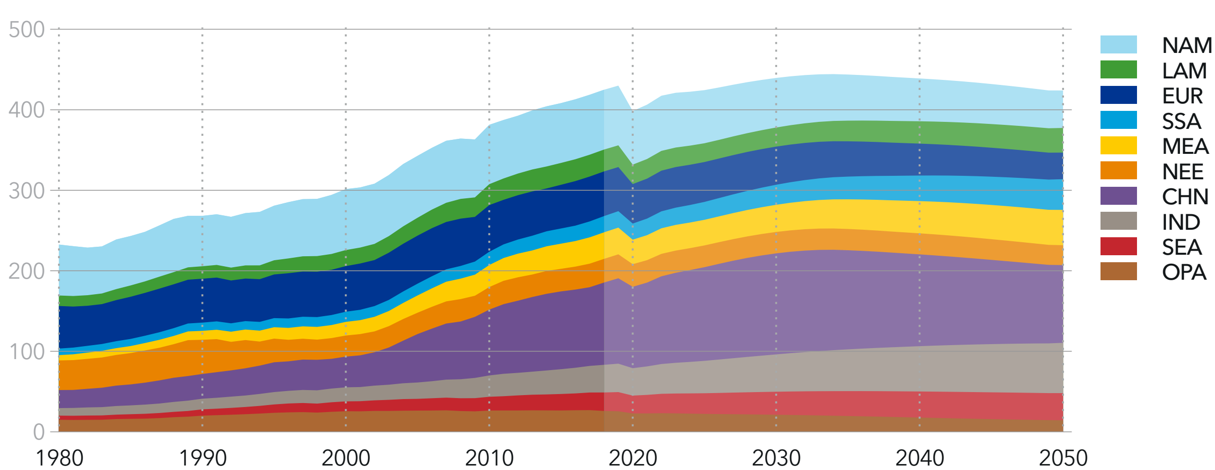
Prior to the shocks caused by COVID-19, energy demand was still set to peak in the mid-2030s, but the peak will now be lower, and the 2020s will follow more of a rebound in energy demand rather than the almost continuous growth experienced prior to 2019. World energy demand will not return to 2018 levels until 2025.

Slower growth in productivity and global population, and continuous increases in energy efficiency, particularly in transport, will account for much of the decline in energy demand towards 2050. Behind this global story are regional narratives that differ significantly.

FIGURE 2.1

Final energy demand by region

Units: EJ/yr



Historical data source: IEA WEB (2019)

Energy demand has already peaked in each of Europe (EUR), North America (NAM), North East Eurasia (NEE), and OECD Pacific (OPA), but will keep rising throughout the forecast period to 2050 in Indian Subcontinent (IND), Latin America (LAM), Middle East and North Africa (MEA), South East Asia (SEA), and Sub-Saharan Africa (SSA). Final energy demand in Greater China (CHN) will peak around 2030 before declining rapidly from the mid-2030s.

Placing world energy demand in the context of decarbonization, we have not seen a transition to fossil-free energy in recent years, despite efforts, but rather renewables becoming an additional energy source to meet increasing energy demand. Now with relatively flat energy demand in the coming decades, this is set to change as lower-emission alternatives capture share from the energy sources that emit carbon when they are burned, and as technologies scale to increase the amount of carbon captured and stored from these sources.

2.1.1 SHIFTS TO NON-FOSSIL FUELS, BUT NATURAL GAS AND OIL TO REMAIN SIGNIFICANT

While global energy demand will recover beyond 2018 levels, oil demand will not: the world has already seen peak oil according to our forecast (Figure 2.2). Compared with our previous forecast, this peak has occurred sooner due to the low oil price induced by a sudden drop in demand caused by COVID-19. While this crash has had a significant impact on financial markets, and potentially on the shorter-term ability of oil and gas companies to invest in new oil and gas projects and in the energy transition, oil still has a significant role to play in the coming decades.

Demand for fossil fuels in general will decline in the lead up to mid-century, according to our forecast. Fossil fuels will account for 54% of primary energy supply in 2050, while non-fossil fuels will make up 46% of the mix. In 2018, 81% of the world's energy was supplied by fossil fuels and 19% by non-fossil fuels. Despite the rapid electrification of the world energy mix that we forecast through significantly increased supply of renewable energy, we forecast that natural gas, followed by oil, will be the two largest primary energy sources at the end of the forecast period (Figure 2.2). Gas will provide 29% of global energy supply in 2050, and oil 16%.

Continued investment in oil and gas will be needed throughout our forecast period to maintain production at levels required to meet global demand, even in a declining market. Capacity additions for oil, which builds additional supply in the expectancy of demand exceeding production from developed oil fields, are forecast to decline from around 4 million barrels per day per year (Mbpd/yr) in 2020 to just above 1 Mbpd/yr in 2050. This contrasts with annual capacity additions for natural gas which are projected to peak in 2031 at 349 billion cubic metres per year (Gm^3/yr), just above the level in 2018, and then decline around 30% to 236 Gm^3/yr.

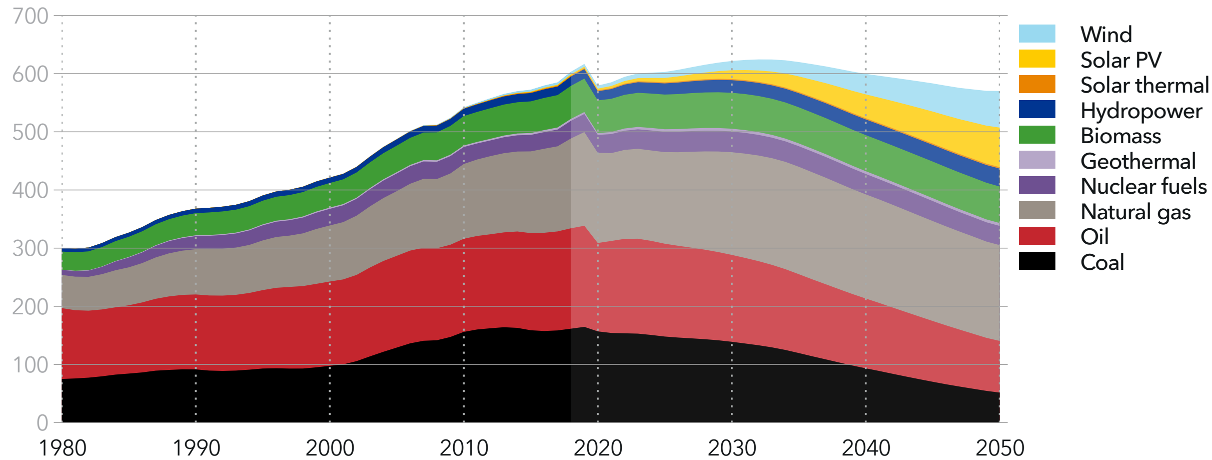
While oil and gas will remain important sources of energy throughout our forecast period, the mix and contribution of renewable energy sources will increase, driven by strong growth in solar PV (12% share in 2050) and wind (11% share in 2050). Solar and wind account for just 1% of energy supply today, illustrating the significant role their rise will play as the world transitions from fossil to non-fossil energy. Biomass will remain relatively steady, rising from 9% today to 11% share of energy supply in 2050.

Surprisingly, and as a clear indication of how much the novel coronavirus has affected world energy supply, coal – an energy source which was surpassed by oil as the largest source of energy in 2014 – will temporarily be the world's largest energy source in 2020, with natural gas a close second. This is because coal has been less affected than oil by drops in demand from transportation during COVID-19 lockdowns around the world. Oil will retake its place as the world largest energy source in 2021, before giving way to natural gas in the mid-2020s. Energy supply from coal will decline, but not at pace until the 2030s, due to persistent demand in some regions. Coal will contribute 9% of the world's primary energy supply in 2050.

FIGURE 2.2

World primary energy supply by source

Units: EJ/yr



Historical data source: IEA WEB (2019)

2.2 MULTIPLE ENERGY TRANSITIONS

We will not see one energy transition to 2050, but several, each interrelated and playing out differently around the world. These include transitions from fossil fuels to renewables, from coal and oil to natural gas, and from fossil fuels to decarbonized gas.

FROM FOSSIL FUELS TO RENEWABLES

The share of renewables used in the supply of energy for power generation will increase from 26% in 2018 to 78% in 2050, significantly reducing emissions as they replace fossil fuels in generating electricity. The vast majority of power will come from solar and wind. Increased electrification, in turn, expands the reach of energy from renewables. Demand for electricity will more than double from 82 EJ in 2018 to 174 EJ in 2050. Demand will come from all sectors, particularly from buildings and from personal vehicles in transport. This will significantly reduce emissions when the electricity is generated from renewable sources. On the flip side, transport will see the greatest drop in fossil energy demand globally, falling to less than 50% during the same period, from 112 EJ in 2018 to 52 EJ in 2050.

FROM COAL AND OIL TO NATURAL GAS

The pace at which the world reduces the carbon intensity of fossil fuels will be a significant factor in the energy transition. Of energy from fossil fuels in 2050, natural gas will provide more than half (54%), with oil supplying 29% and coal 17%. These three fossil fuels today account for almost exactly a third each of global fossil fuel energy. While the path will be more complex than one simply replacing the other, that is ultimately the outcome. Oil's share will fall moderately in this context, while coal will give way to gas, the least carbon intensive fossil fuel. The pace at which this happens will be a significant factor in the race to decarbonize. The rise of gas is influenced by several factors, including a push to lower carbon intensity and policies to maintain energy security. More than this though, the price of natural gas will determine the degree to which it takes share from coal in the world's energy supply.

FROM FOSSIL FUELS TO DECARBONIZED GAS

Hydrogen – produced from both renewables via electrolysis and fossil fuels with carbon capture and storage (CCS) – will play a key role in decarbonizing gas consumption, helping to reduce emissions from hard-to-abate sectors that are difficult to feasibly electrify, including shipping, aviation, large vehicle transport and areas of manufacturing. We project that hydrogen will supply 23% of end-user demand for gas (natural gas and hydrogen).

On the supply side, we project that 13% of natural gas supply will be decarbonized in 2050. This follows rapid growth in production of hydrogen from natural gas, and use of natural gas with carbon capture and storage (CCS) in power and industry towards the end of our forecast period. In turn, world CCS capacity will increase from around 40 million metric tonnes of carbon dioxide a year ($MtCO_2$/yr) today to almost 2,200 $MtCO_2$/yr in 2050. We further explore the role of hydrogen and CCS in the energy transition in sections 3.5 and 3.6, respectively.

2.3 PEAK OIL DEMAND, BUT NOT EVERYWHERE

Our Outlook forecasts global primary oil demand will fall 13% in 2020, reaching a level not seen since the early 2000s. It will rebound somewhat to 2023, before declining gradually to half of its 2018 level in real terms by 2050. While oil demand has reached its highest level globally, as with many aspects of the energy transition, the pace and nature of changes differ from region to region (Figure 2.3). Oil demand will continue to grow in Greater China to the late 2020s, South East Asia until the early 2030s, on the Indian Subcontinent until 2040, and in Sub-Saharan Africa beyond the end of our forecast period in 2050.

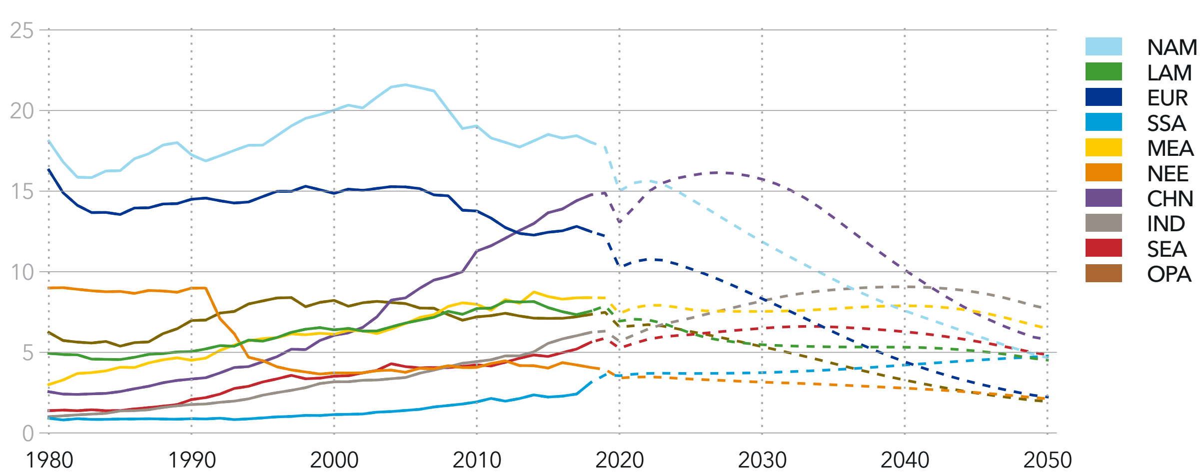
On the Indian Subcontinent this will be led by a significant increase in internal combustion engine vehicles (ICE-Vs) for personal use, as well as demand from the region's competitive and substantial refining and petrochemicals sector. In Sub-Saharan Africa, increased oil demand will be led by increases in commercial and personal ICE-Vs, as well as growth in demand from shipping, aviation, and petrochemicals. Oil demand in Middle East and North Africa, and in South East Asia, will remain relatively consistent through to 2050. Together, these four regions (IND, SSA, MEA, SEA) will account for 53% of oil demand in 2050, compared with 27% in 2018.

Increases in these regions will temper the declines in oil elsewhere. Europe, North America, and OECD Pacific will see rapid declines; they (EUR, NAM, OPA) accounted collectively for 43% of oil demand in 2018, but only 20% in 2050.

FIGURE 2.3

Oil demand by region

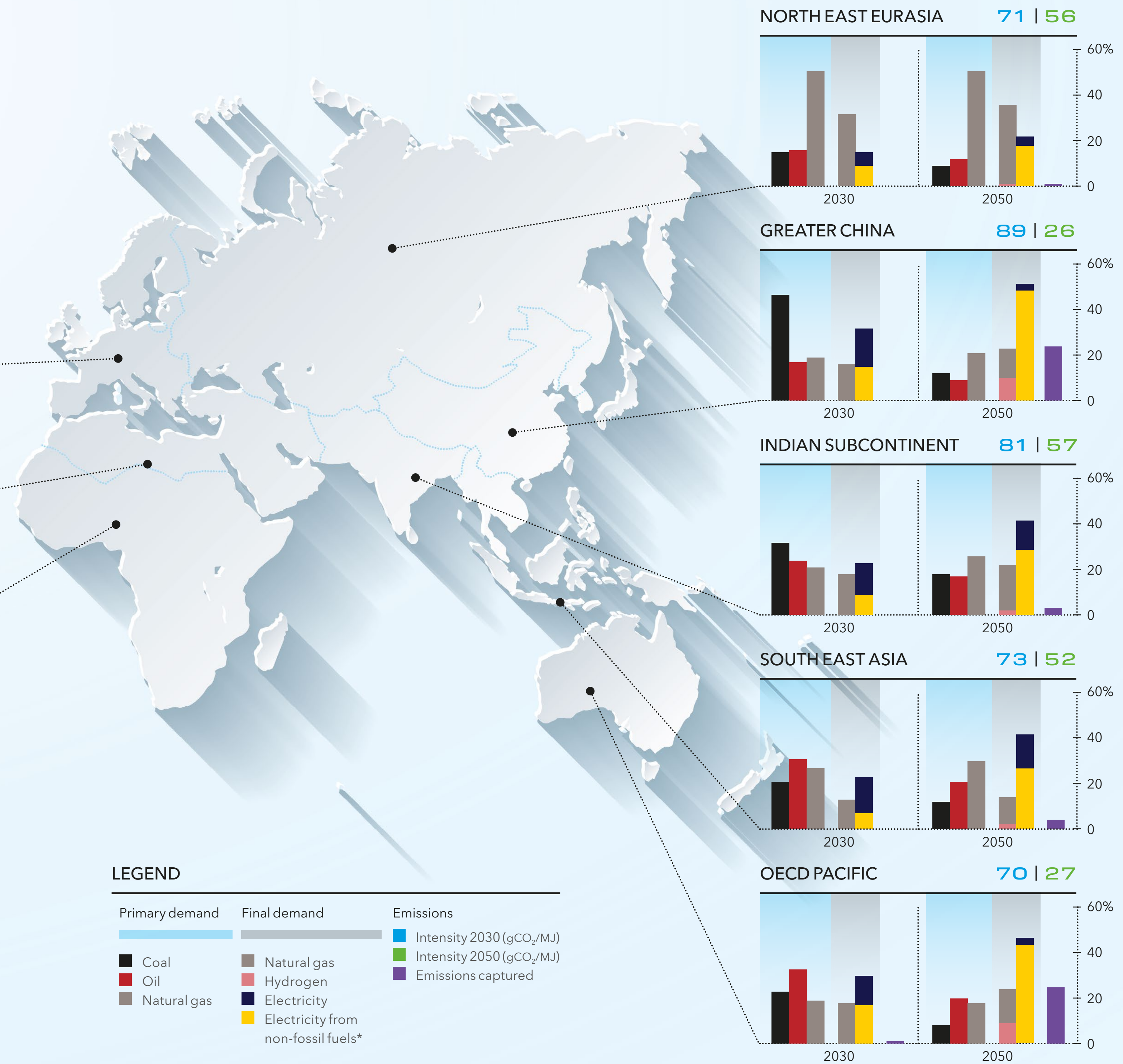
Units: Mb/d



Does not include natural gas liquids and bioliquids. Historical data source: IEA WEB (2019)

MULTIPLE ENERGY TRANSITIONS

**Biomass accounts for around half of energy supply in Sub-Saharan Africa throughout the forecast period, significantly higher than in other regions. This explains the lower numbers presented here.



*Non-fossil sources include solar, wind, nuclear, hydropower, and biomass

Declines in oil demand are largely due to a shift to battery-electric (BEV) or hydrogen fuel-cell vehicles in passenger and commercial transport, modal shift of commercial transport to rail, and the increased efficiency of next-generation combustion engines. Latin America will see a moderate decline from the early 2020s through to 2050, as it will not see the same level of falling oil demand from the transport sector.

In Greater China, the story is more mixed. Demand will increase moderately throughout the 2020s led by personal ICE-Vs, before seeing a rapid decline to 2050 as these are replaced with BEVs, and as natural gas, hydrogen, and biomass replace oil in other forms of transportation. Demand from aviation will increase through to 2030 before levelling off.

2.3.1 TRANSPORT SECTOR DRIVES DECLINE IN OIL DEMAND

In 2020, it has been clear to see the effects of the transport sector on oil demand, as much of the world's domestic and international travel came to a standstill for a period, causing oil demand for transport to fall by 17% compared to 2019 (Figure 2.4).

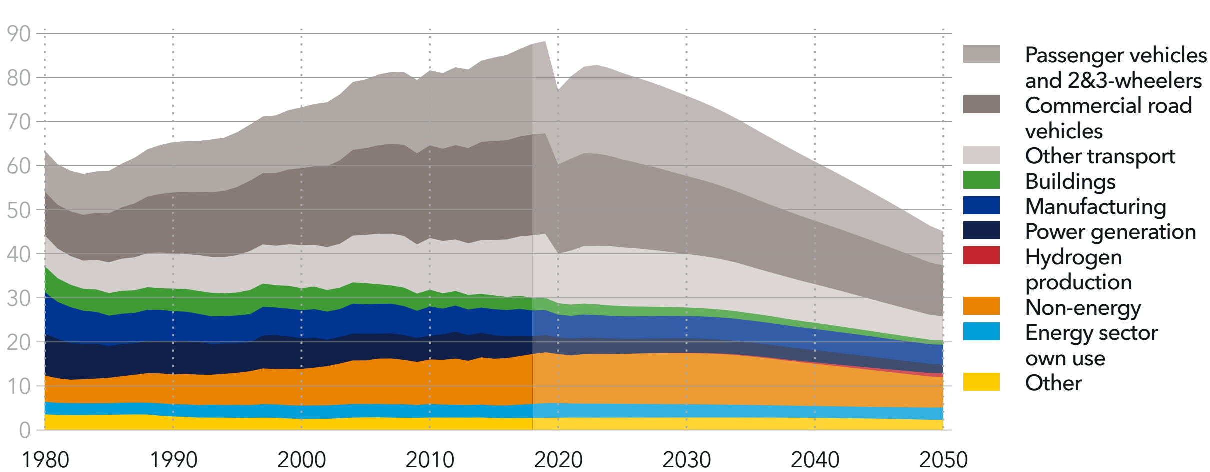
Increases in demand for oil since the 1980s have come largely from the transport sector, with oil having supplied more than 90% of total energy used in the sector. Throughout the forecasting period, transport remains a major source of oil demand, but this will decline rapidly from the mid-2020s (Figure 2.5). Oil will account for 46% of energy use in transportation by 2050, half of the 93% share it provided in 2018. In real terms, oil demand from transport will decline by 57% between 2018 and 2050, from 109 EJ to 46 EJ. Taken together, non-hydrocarbon energy carriers will account for 48% of energy use in transportation in 2050, compared with only 4% in 2018.

Electrification of passenger vehicles will lead the way, with half of all passenger vehicles sold being electric by 2032. This is followed by natural gas, biogas, and later hydrogen, which are set to increasingly supply the energy for larger forms of road transport and shipping. More specifically, oil demand from road vehicles will fall by more than half to 36 EJ in 2050, from 82 EJ in 2018. Demand for oil from shipping will fall throughout the forecast period to almost completely disappear from the world fleet by mid-century, from 11 EJ in 2018 to less than 1 EJ

FIGURE 2.4

World oil demand by sector

Units: Mb/d



Does not include natural gas liquids and bioliquids. Historical data source: IEA WEB (2019) in 2050, as oil is replaced by liquefied natural gas (LNG) and alternative shipping fuels such as hydrogen, ammonia, and methanol. Oil demand from aviation will rebound from the crash in 2020 to reach close to the levels of 2018 at 13 EJ in 2030, before falling gradually to 9 EJ in 2050, as biofuels increasingly replace oil in aviation. In 2050, the split in demand for oil from the transport sector will be 78% from road, 19% aviation, 1% maritime, and 2% rail. This compares to a split in 2018 of 75% from road, 13% aviation, 10% maritime, and 1% rail.

In other sectors, oil demand will stay strong for feedstock (including for petrochemicals) to the mid-2030s, before seeing modest declines to 2050 as total fossil demand decreases from this sector – with oil taking the brunt of the fall compared with natural gas. Feedstock will account for 15% of oil demand in 2050. Oil demand from manufacturing will remain steady throughout our forecast period, accounting for 11 EJ or 7% of oil demand today, and seeing a modest decline of 3 EJ in real terms to 2050. Today's relatively small 3% share of oil demand from buildings will decline steadily to 2050, largely as the sector becomes increasingly electrified in order to heat and cool homes and businesses.

2.4 COST TO WIN IN A DECLINING OIL MARKET

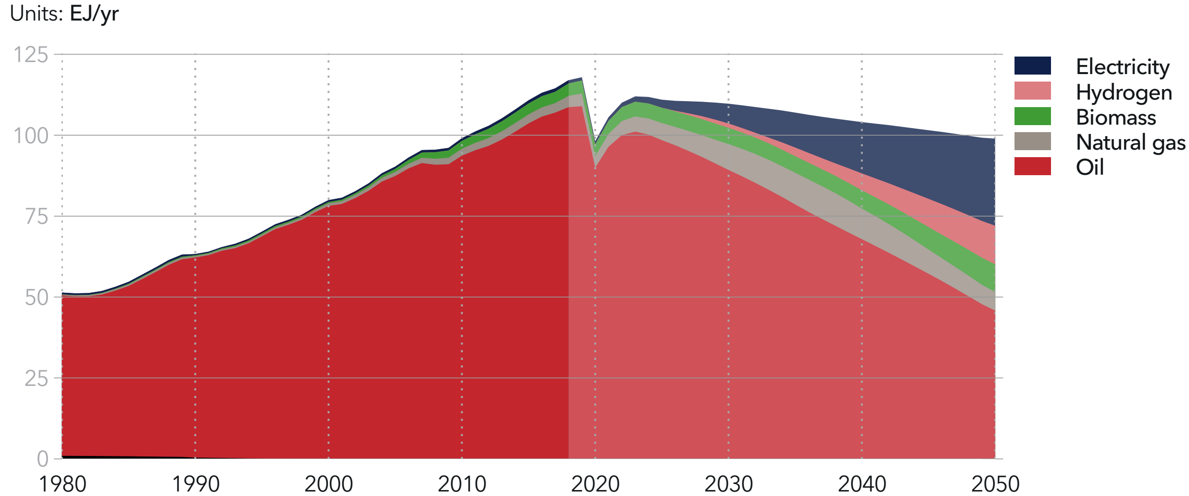
Overall, we forecast steadily declining global crude oil production to 2050, roughly halving from 83 Mb/d in 2018 to 42 Mb/d in 2050. Amid declining overall production, conventional onshore oil will continue to provide the largest and most stable share of total oil production.

Much of the expansion in oil production in recent decades has come from offshore production, together with the more recent boom from unconventional sources – largely as a result of US shale. Onshore conventional production has remained relatively stable for decades at around 40 Mb/d. Now in a declining oil market, the cheapest, easiest-to-access oil is set win in the long run, as the industry faces significant pressure on cost. This has regional implications, with Middle East and North Africa and to a lesser degree North East Eurasia set to reap the benefits. Shifts from more oil to cheapest oil will put increasing pressure on unconventional onshore and offshore oil production to 2050. Unconventional oil, largely US shale, will see moderate increases in the mid-term, before declining.

FIGURE 2.5

World transport sector energy demand by carrier

Units: EJ/yr



Historical data source: IEA WEB (2019)

This will be driven largely by North America, which will account for most of the unconventional production through to 2050. Offshore oil production will decline gradually throughout the forecast period, as the overall oil market declines and as it loses out to cheaper conventional onshore production later in our forecast period.

Upstream oil expenditure in 2050 will be one third of the levels in 2018. From the late-2030s, we see an uptick in capacity additions for conventional onshore oil, as we see a steep decline in additions for offshore oil closely followed by a decline in additions for unconventional onshore.

Today, North America, Middle East and North Africa, and North East Eurasia combined account for 68% of global oil production, producing 56 Mb/d of a total 83 Mb/d in 2018. By 2050, they will collectively account for 90% of world oil production (Figure 2.6). Yet, they will only consume 30% of world oil. They are the only regions set to be net oil exporters in 2050. Among other significant producers, Latin America production will roughly equal regional demand until the mid-2030s, while Sub-Saharan Africa will be a net exporter until the 2040s.

2.4.1 MIDDLE EAST AND NORTH AFRICA TO BENEFIT, AS CONVENTIONAL ONSHORE OIL STAYS THE COURSE

In real terms, conventional onshore oil production will decline steadily to the mid-2030s before levelling out, with moderate increases and decreases along the road to mid-century. But, as a share of total oil production, it will account for more than 65% of global oil production at mid-century, compared with 53% in 2018 (Figure 2.7).

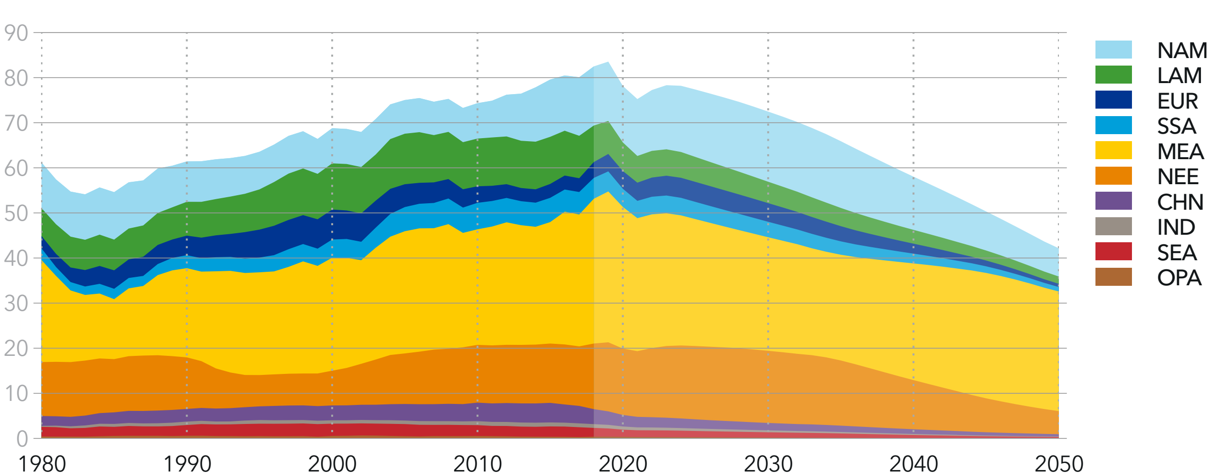
Middle East and North Africa will account for 85% of conventional onshore oil production by mid-century. This means that among producers, the Middle East and North Africa will out-compete other regions in the long run. Oil production in the region will remain relatively stable to 2050, buoyed by significant capacity additions from the mid-2030s. Almost all the world's conventional onshore capacity additions will come from the Middle East and North Africa from 2035 onwards (Figure 2.8). In contrast, both North America and North East Eurasia will see declining production from the mid-2030s.

Our model assumes that regional supply increases are driven by large-scale, low-cost oil resources, especially in Middle East and North Africa as

FIGURE 2.6

Crude oil production by region

Units: Mb/d

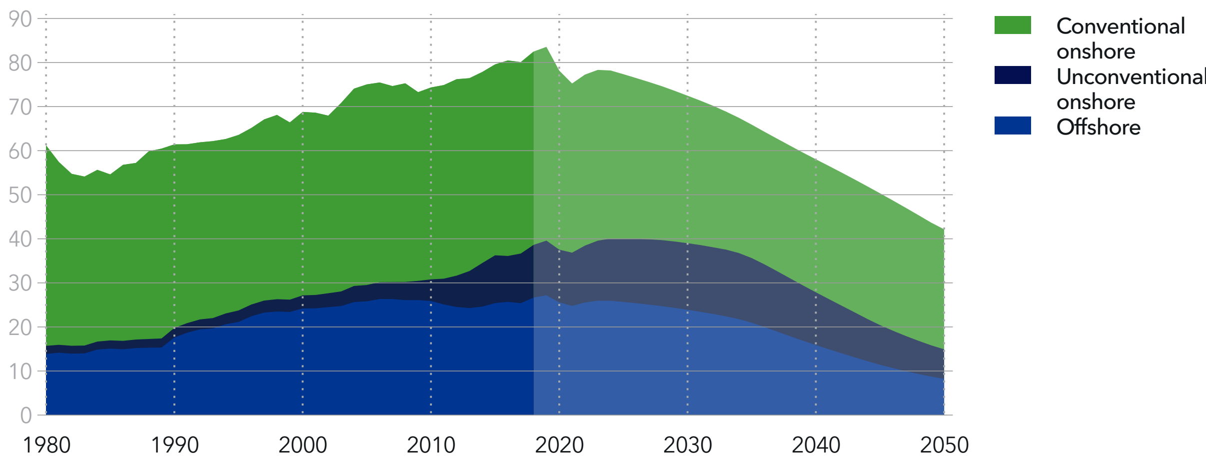


Crude oil production only. Does not include natural gas liquids. Historical data source: IEA WEB (2019)

FIGURE 2.7

World crude oil production by field type

Units: Mb/d



Does not include natural gas liquids and bioliquids. Historical data: Rystad (2019)

producers respond to growing relative abundance by asserting competitive advantage. Part of this story is that oil production will increasingly come from known reserves, as producers focus on efficiency in extracting more from existing wells, rather than the capital-intensive exploration and development of new fields.

2.4.2 OFFSHORE OIL AND SHALE UNDER PRESSURE

The shift from more oil to cheaper oil in a declining market will increase pressure on offshore and unconventional onshore oil production to 2050, as conventional onshore from the Middle East and North Africa is set to win on cost. Offshore oil production will fall by more than two thirds to 2050, while onshore unconventional will fall by almost half. This compares to a fall of under 40% for conventional onshore, and around a 50% decline in total oil production during the forecast period.

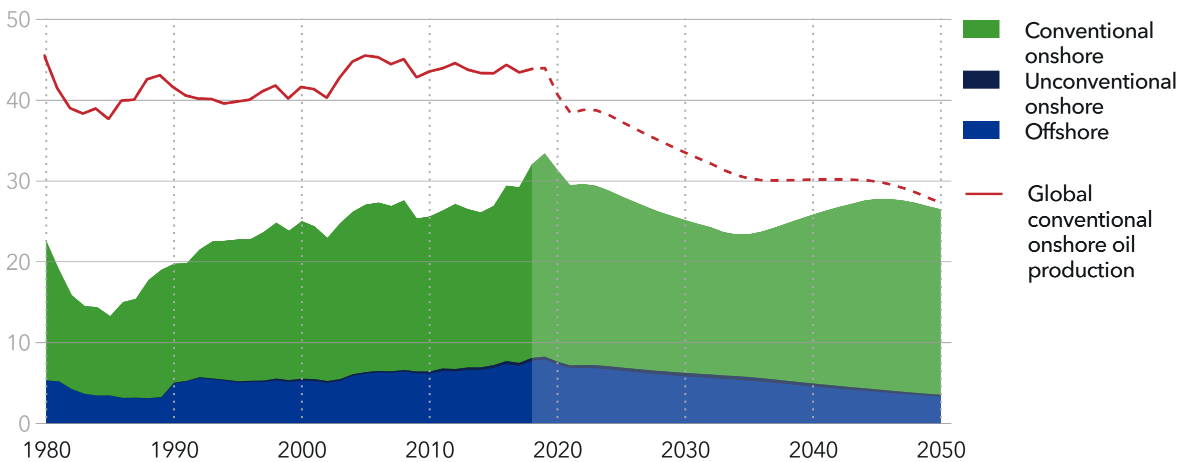
Unconventional onshore oil could stay more resilient than offshore oil due to greater flexibility to turn the taps on and off amid uncertainty – such as the shocks to the market in 2020. In turn, while offshore oil production could be held back by the capital-intensive cost of going offshore amid declining oil demand, it could also beat shale on cost per barrel, particularly if the cost of greenhouse gas emissions becomes an increasing factor. Operators have reported break-even costs of USD 30 per barrel for some large offshore assets.[6] At these costs, offshore oil could outcompete shale, but this may not be enough to make such assets commercially competitive with onshore conventional oil in the long run.

On one side, regional drives to ensure energy security and maintain revenues from fossil fuels could also play a role in maintaining offshore oil production. On the other, societal pressure and targets to reduce emissions could hold offshore oil back in some regions. Climate ambitions and targets are driving international oil companies (IOCs) to focus on becoming broader energy companies, increasingly investing in renewables and clean energy sources – though for most IOCs these green investments currently pale in comparison with their oil and gas investments.[7] It is these IOCs that would have traditionally developed frontier oil and gas resources from challenging environments and reservoirs, as the scale of investment required for the exploration and production of these resources often places them outside the range of risk that newer, mid-sized, pure hydrocarbon players would consider.

FIGURE 2.8

Middle East and North Africa crude oil production by field type

Units: Mb/d



Does not include natural gas liquids and bioliquids. Historical data: Rystad (2019)

Analysis published by Wood Mackenzie in November 2018 highlighted that 74% of deepwater reserves were being progressed by only eight operators, all of them IOCs. Since 2019, more than half of the IOCs[8] mentioned in that analysis have made commitments to lower or net-zero emissions (see Section 3.3.1), building increasingly diverse portfolios outside traditional oil and gas, with offshore renewables set to be a key focus. Of senior professionals who responded to DNV GL's research on the outlook for the oil and gas industry in 2020, 63% reported offshore wind as the most likely area to increase investment outside oil and gas.[9]

2.4.3 US SHALE LEADS CAPACITY ADDITIONS TO 2040, WITH NORTH AMERICA SET TO SWITCH FROM NET OIL IMPORTER TO EXPORTER

Total oil capacity additions will decline throughout the forecast period, with additions in 2050 being just 20% of the levels seen in 2018. Within this, all field types will see capacity additions decline gradually to the late 2030s. After that, onshore conventional oil will see an uptick in capacity additions, as these fields dominate oil production to mid-century.

In the shorter term, unconventional onshore oil will lead capacity additions. This is due to a steady level of unconventional production in the coming years, together with shorter capacity lifetimes for these fields. Due to these factors, even after onshore conventional oil comes to dominate the market from 2040, unconventional onshore will continue to see moderate additions in order to maintain production levels, albeit at a much lower level than today.

North America accounted for more than 85% of unconventional onshore oil capacity additions in 2018 and will account for more than 80% of unconventional capacity additions each year until 2045, before dropping to 75% in 2050. Much of this will come from US shale. Assisted by falling oil demand in North America, the region is set to shift from being a net importer to become a net exporter of oil in the mid-2020s (Figure 2.9).

For conventional onshore oil, with lower depletion rates, longer capacity lifetimes and more assets under production, fewer capacity additions will be needed in the short term to maintain production.

Spare capacity from proven resources allow onshore oil capacity additions to largely displace new capacity from unconventional and offshore fields from late-2030s.

Offshore oil will see capacity additions drop across all regions from 2040, as the squeeze on demand from conventional onshore oil outpaces depletion levels. The fall in offshore additions is set to come ahead of a fall in unconventional onshore additions, partly due to the longer capacity lifetime of offshore assets.

2.4.4 OIL REFINING IN DECLINE, WITH DEMAND SHIFTING FROM TRANSPORT TO PETROCHEMICALS

Refinery output took a hit in 2020, falling by around a sixth to levels not seen for 20 years. We forecast that this drop will be permanent, and output will more than halved from around 98 Mb/d in 2018 to around 43 Mb/d in 2050.

This is due to significantly reduced demand for liquid fuels in the transport sector. We expect greater refining sector focus on producing cleaner, higher-grade transport fuels in mature markets with existing infrastructure. Transportation of refined products is likely to decline as refinery output adjusts to delivering only what local markets need. Greater proportions of refinery oil output will be directed towards the petrochemicals sector as feedstock rather than fuels.

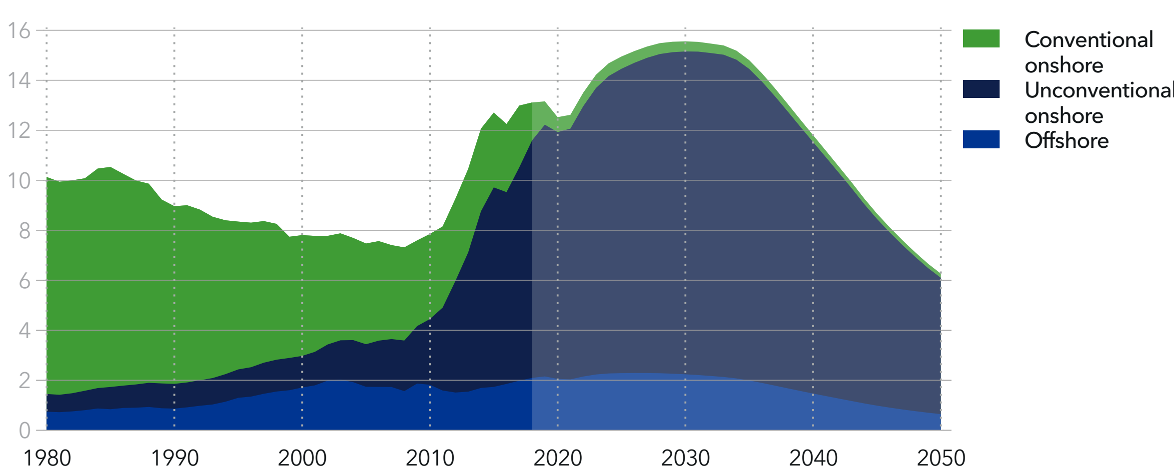
The most dramatic falls in oil refining will come from Europe, North America, and OECD Pacific. In contrast, the Indian Subcontinent, South East Asia, Sub-Saharan Africa, and, to a lesser degree, Greater China will maintain or increase output, at least for part of the forecast period.

Refiners will need to re-balance their product slates to reflect lower demand for liquid fuels, for road, rail, and maritime consumption, and greater demand for petrochemicals in most regions, particularly in Greater China, the Indian Subcontinent and Sub-Saharan Africa. New product slates will also need to meet changing environmental standards, such as the International Maritime Organization's limits on sulfur in fuel in international shipping from 2020.

FIGURE 2.9

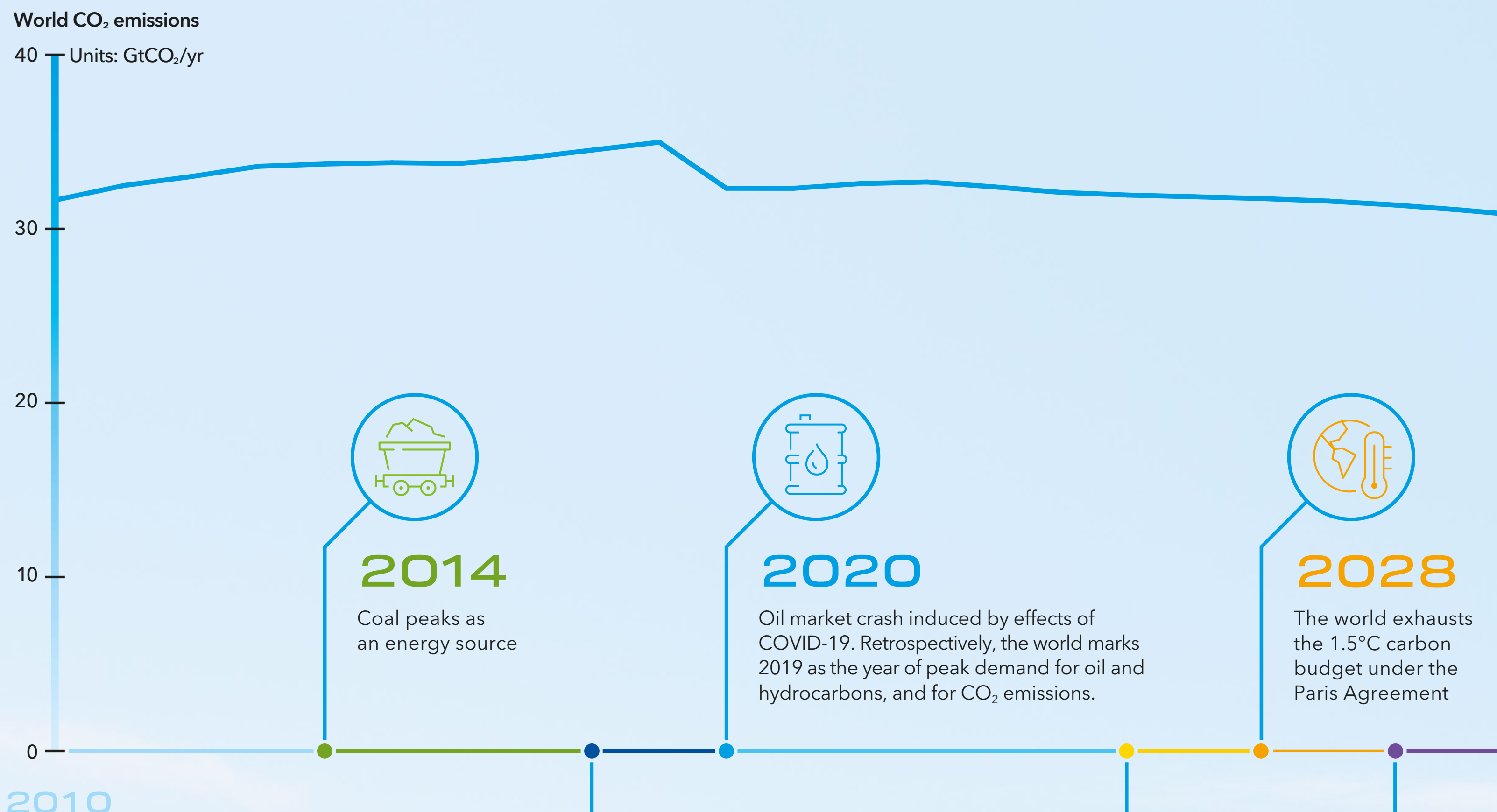
North America crude oil production by field type

Units: Mb/d



Does not include natural gas liquids and bioliquids. Historical data: Rystad (2019)

ENERGY TRANSITION TIMELINE: THE OIL AND GAS HORIZON



2014
Coal peaks as an energy source

2018
Fossil fuels provide 81% of world energy supply (benchmark year for this report).

2020
Oil market crash induced by effects of COVID-19. Retrospectively, the world marks 2019 as the year of peak demand for oil and hydrocarbons, and for CO_2 emissions.

2026
Natural gas becomes the world's largest energy source

2028
The world exhausts the 1.5°C carbon budget under the Paris Agreement

20
LNG liqu
and reg
doubles
benchm
capex sp

030

uification capacity triples
asification capacity
s, compared to 2018
ark. This follows an LNG
pike in the mid-2020s

2035

Hydrogen and CCS start to scale, increasing use of decarbonized gas and green gas – and helping to decarbonize hard-to-abate sectors

2036

Non-fossil sources combined overtake gas as the world's largest energy source

2045

Greater China overtakes Europe to lead the world in demand for hydrogen and CCS capacity

2050

Fossil fuels provide 54% of world energy supply

2051

The world exhausts the 2°C carbon budget under the Paris Agreement

Forecast by our 2020 Energy Transition Outlook model

2.5 NATURAL GAS TO BECOME WORLD'S LARGEST ENERGY SOURCE

As the least carbon-intensive fossil fuel, gas will play a prominent role in the energy transition, taking its place as the world's largest energy source in the mid-2020s.

Around half of demand for natural gas will come directly from its end use – in buildings, manufacturing, transport, and non-energy use such as for petrochemicals (Figure 2.10). The other half of demand will come from power generation, providing the energy security and stability the world needs alongside variable renewables in the transition, and later from hydrogen production, as well as from own use (demand from the oil and gas and energy industries during production and distribution).

Global gas demand will peak in the mid-2030s at 185 EJ, around 20% higher than the 154 EJ in 2018. From that point it will decline by just over 10% to 165 EJ at mid-century.

2.5.1 CHINA, INDIA TO DRIVE DEMAND FOR NATURAL GAS

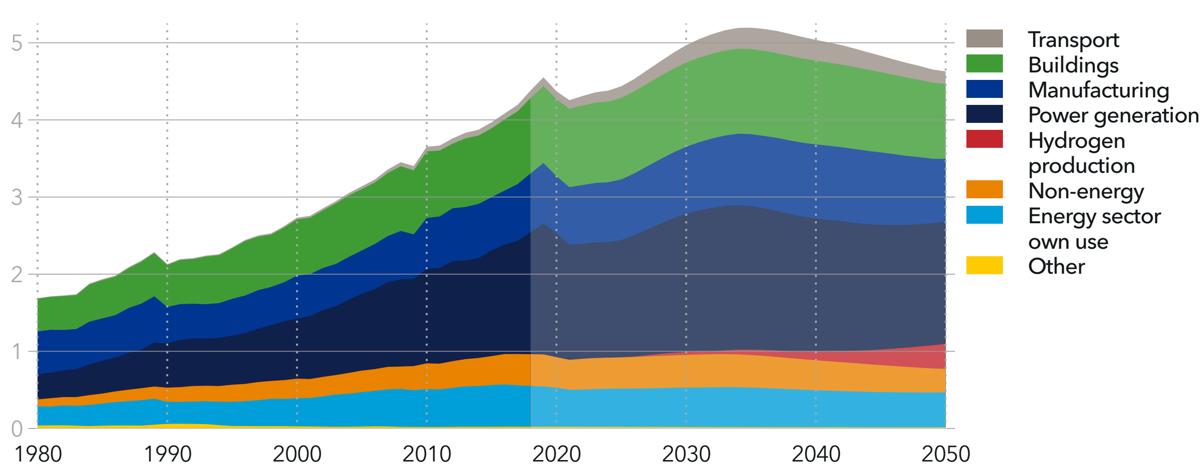
Greater China and the Indian Subcontinent will see primary demand for natural gas double in real terms to 2035 (Figure 2.11). Combined, these two regions accounted for 14% of total natural gas demand in 2018. This will rise significantly to 30% by 2035 and continue at a similar share to 2050. Demand growth will continue on the Indian Subcontinent to the end of the forecast period, albeit at a more gradual level than before 2035. In Greater China, natural gas demand will decline to mid-century, falling by around 30% from 2035 levels, though it will still account for 17% of world gas demand by 2050. Significantly, these regions will produce only a fraction of the gas they consume. Both regions are set to see strong policy support for natural gas consumption, at least in the short term, and this will lead to the regions together accounting for 75% of net gas imports in 2035 and 80% in 2050. Demand for gas around the world will be driven significantly by policy, for more on this, see Section 3.4.

South East Asia will see growth in demand for natural gas not far behind Greater China and the Indian Subcontinent to 2035.

FIGURE 2.10

World natural gas demand by sector

Units: Tm³/yr



Includes natural gas liquids. Historical data source: IEA WEB (2019)

This will continue to increase to the end of the forecast period to 9% of global natural gas demand in 2050, compared with 5% in 2018. The region becomes a net importer, as increasing gas production fails to keep up with the pace of demand.

Demand for natural gas from Middle East and North Africa, North America, and North East Eurasia will remain strong in real terms with little change in the next 15 years, with these regions collectively accounting for 46% of global demand in 2035. Demand from North America and North East Eurasia will then gradually decline to 2050, while demand stays strong in Middle East and North Africa, with the region set to account for the largest gas demand among regions in 2050. These three regions will be significant net exporters of natural gas despite the large demand for natural gas in their own markets.

Europe, Latin America, and OECD Pacific will see gradual declines in natural gas demand to 2050. Combined, they accounted for 23% of demand in 2018 and will account for 13% by 2050. Europe and Latin America will be gas importers throughout the forecast period, while OECD Pacific will switch to a net exporter in the early 2020s, led by significant LNG exports from Australia.

Sub-Saharan Africa will see continued growth through the forecast period, albeit from a low level, increasing from around 1% of global natural gas demand in 2018 to almost 4% in 2050.

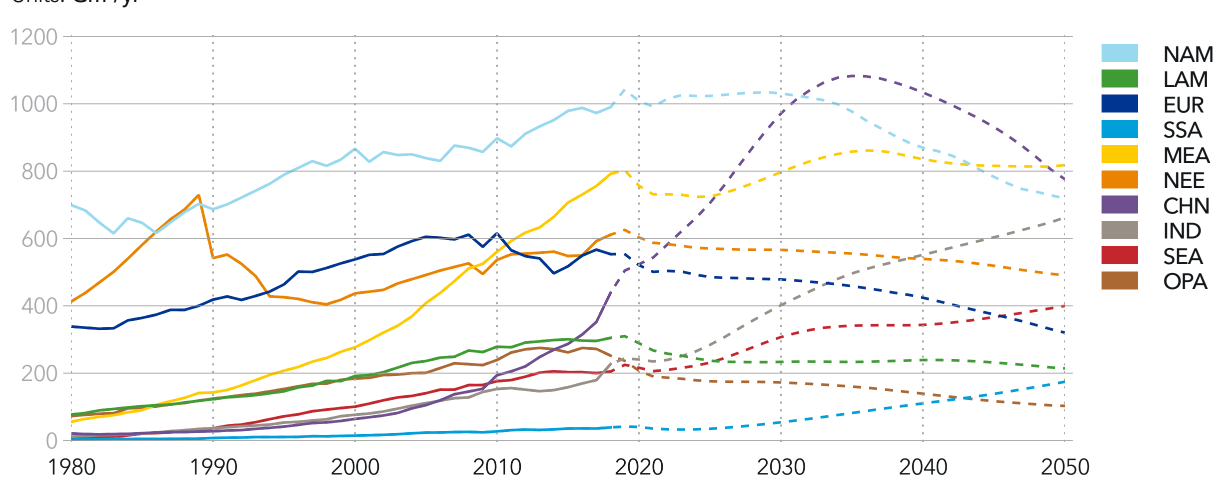
2.5.2 INCREASED GAS DEMAND ACROSS ALL SECTORS TO 2035

Demand for natural gas is set to increase across all sectors to the mid-2030s. Power generation will account for more than a third of primary demand for gas through to 2050, accounting for the greatest share of natural gas demand among sectors. In real terms, demand for natural gas from power generation will increase by almost a fifth from 2018 to 2035 globally, largely due to increased demand in Greater China, the Indian Subcontinent, and South East Asia, which outpaces growth in renewables. By 2050, demand for natural gas for power generation will drop back down to 2018 levels, as renewables scale.

FIGURE 2.11

Natural gas demand by region

Units: Gm^3/yr



Includes natural gas liquids. Historical data source: IEA WEB (2019)

From a relatively low starting point, natural gas demand from transport will almost triple to 2035, before dropping by half to 2050, linked to the rise of hydrogen in transport during this period. Manufacturing demand will increase steadily before dipping in the late 2040s. Demand for natural gas from buildings will see a small gradual increase before then falling in the 2040s, giving way to increasing electrification and hydrogen. Non-energy (largely petrochemicals) and own use (demand from the oil and gas and energy industries during production and distribution) are the only sectors that will see marked falls in demand for natural gas between 2018 and 2050. All other sectors will increase or be close to maintaining levels of demand. Decreases in own use will likely come from efficiency gains, from the electrification of production facilities, and from less flaring.

Non-energy use of natural gas has increased rapidly in the past decade alongside greater demand for petrochemicals and for other uses of natural gas as feedstock. This will increase to the mid-2030s, before gradually declining, as demand falls for products that use natural gas as feedstock. Hydrogen produced from renewables may also displace some of the natural gas demand for feedstock from the mid-2030s.

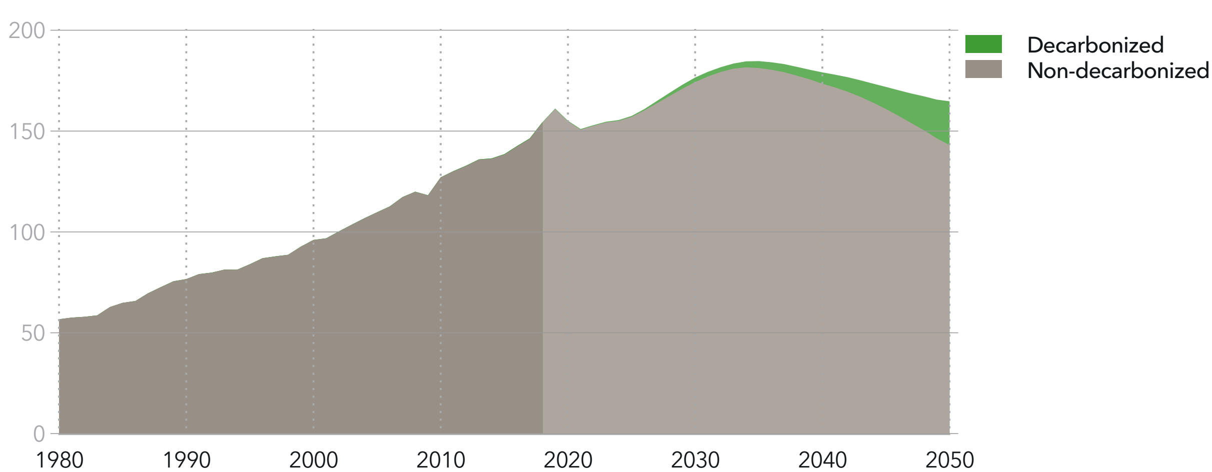
2.6 TRANSITION TO DECARBONIZED AND GREEN GAS FROM THE MID-2030S

Primary energy demand for natural gas will decline from the mid-2030s, according to our forecast. From this point, three significant things happen. First, the amount of natural gas used for power generation starts to fall as renewables scale significantly and electricity is increasingly used to replace natural gas in sectors where it is feasible to do so. Second, natural gas will be partially decarbonized through gas reforming with CCS to produce blue hydrogen, with us predicting rapid growth in this towards the end of our forecast period. Third, green hydrogen, produced from renewables, will join decarbonized gas in replacing some of the demand for natural gas, largely in hard-to-abate sectors.

FIGURE 2.12

World primary natural gas supply

Units: EJ/yr



Historical data source: IEA WEB (2019)

Our forecast projects that 13% of gas will be decarbonized in 2050 (Figure 2.12). This follows rapid growth in producing hydrogen from natural gas, and of natural gas with CCS in power and industry, towards the end of our forecast period.

In terms of lowering the emissions of natural gas consumption, we project that hydrogen (produced from fossil fuels with CCS and from renewables via electrolysis) will supply 23% of end-user demand for gas (natural gas and hydrogen). Around half of this hydrogen will be produced from fossil fuels in 2050, with around 70% of this coming from natural gas. The other half will be produced from electricity, predominantly from renewable sources. Both the decarbonization of gas through CCS and the use of hydrogen as a vector to reduce emissions from gas consumption will be led by Europe, Greater China North America and OECD Pacific.

2.7 GAS PRODUCTION DOMINATED BY THREE REGIONS

North America, Middle East and North Africa, and North East Eurasia will dominate natural gas production, accounting for around 75% of the world's supply throughout the forecast period (Figure 2.13).

Gas production will increase 12% from 4,520 Gm³/yr in 2018 to 5,070 Gm³/yr in 2035, before decreasing to 4,570 Gm³/yr – a level marginally higher than in 2018. Production from all field types will increase to 2035. Unconventional onshore gas will see the greatest proportion of this, followed by conventional onshore and then offshore, though all three sources of supply will remain competitive.

North America will continue to be the world's largest gas producer to 2050, accounting for more than 90% of unconventional onshore gas production during the forecast period, due to significant volumes of shale gas continuing to come out of the US. Total gas production from the region will rise to around 1,500 Gm³/yr a little after 2030 and stay close to this level to 2050.

The region is followed by Middle East and North Africa at more than 1,100 Gm³/yr from 2030 to 2050, and North East Eurasia at around 1,000 Gm³/yr from 2030 to the mid-2040s, before falling a little to 2050. From a strong position today, these two regions will come to dominate conventional onshore gas production, accounting for 85% of 1,990 Gm³/yr in 2050, compared with 67% in 2018.

Offshore gas production will be more distributed, with many regions getting in on the action. Middle East and North Africa, OECD Pacific, South East Asia, and Sub-Saharan Africa will each produce roughly 200 Gm³/yr of just over 1,200 Gm³/yr of global production in 2050, with Europe, Latin America, and North East Eurasia each producing around 100 Gm³/yr. This will lead to OECD Pacific and Sub-Saharan Africa joining Middle East and North Africa, North America, and North East Eurasia as gas exporters throughout the forecast period. South East Asia will switch from a net exporter to importer around 2030.

2.7.1 GAS CAPACITY ADDITIONS TO REBOUND TO 2030, BUT FALL TO MID-CENTURY

Gas capacity additions have fallen substantially following the market crash in 2020, but this will be short lived. All field types will see capacity rise up to 2030, when total additions will return to 2018 levels. By 2050, total annual capacity additions will be around 235 Gm³/yr, down 35% from 360 Gm³/yr in 2018.

In terms of field type, unconventional onshore will lead capacity additions throughout, accounting for 51% of total annual additions in 2018 and 56% in 2050, at around 130 Gm³/yr. Conventional onshore gas will remain steady, with annual additions accounting for almost 50 Gm³/yr in 2050.

Offshore annual additions will remain relatively flat throughout the period, at 55 Gm³/yr in 2050. When compared with the forecast for oil production during the period (see Section 2.4.3), we see that offshore gas production will stay more competitive. This is partly due to continued strong demand for gas, bringing more certainty that investments with longer horizons will make a return on investment, and partly due to the price advantage of regional supply by (offshore) pipelines over LNG imports, particularly in regions with well-developed gas infrastructure.

2.8 HUGE GROWTH IN LNG, AS GLOBAL GAS IMPORTS SET TO DOUBLE

2.8.1 NATURAL GAS TO SEE SIGNIFICANT INCREASE IN INTERREGIONAL TRADE

Global imports in natural gas are set to more than double between 2018 and 2035, from around 745 Gm³/yr to 1,685 Gm³/yr, and will remain at this level throughout the forecast period (Figure 2.15). This will mean a quarter of world gas demand will be traded between net import and net export regions by 2035. Much of this will come in the form of LNG exports, as gas fuels increasingly move over the oceans. We forecast that seaborn trade of natural gas (LNG and liquefied petroleum gas combined) will increase fourfold from 415 million metric tonnes per year (Mt/yr) in 2018 to 1,680 Mt/yr in 2050.

Supporting this significant increase in interregional trade, liquefaction capacity is set to triple over the next decade to 1,200 Mt/yr, before plateauing until 2050. From almost no capacity today, North America will account for just under half (560 Mt/yr) of this capacity in 2030, accounting for much of the increase.

Today, most of the liquefaction capacity comes from the Middle East (Qatar) and OECD Pacific (Australia), with these regions set to make up much of the rest of LNG liquification capacity throughout the forecast period. North East Eurasia will continue to be a major gas exporter during the period, and while the region will see some increase in liquefaction capacity, pipelines are likely to distribute much of the exports. Significant volumes of Russian gas are set to supply Europe and Asia, through existing or planned transnational pipelines including Nord Stream, Nord Stream 2, TurkStream, and the proposed Altai ('Power of Siberia 2') pipeline to China, and also shipped from Yamal and Arctic LNG II fields by fleets of LNG carriers.

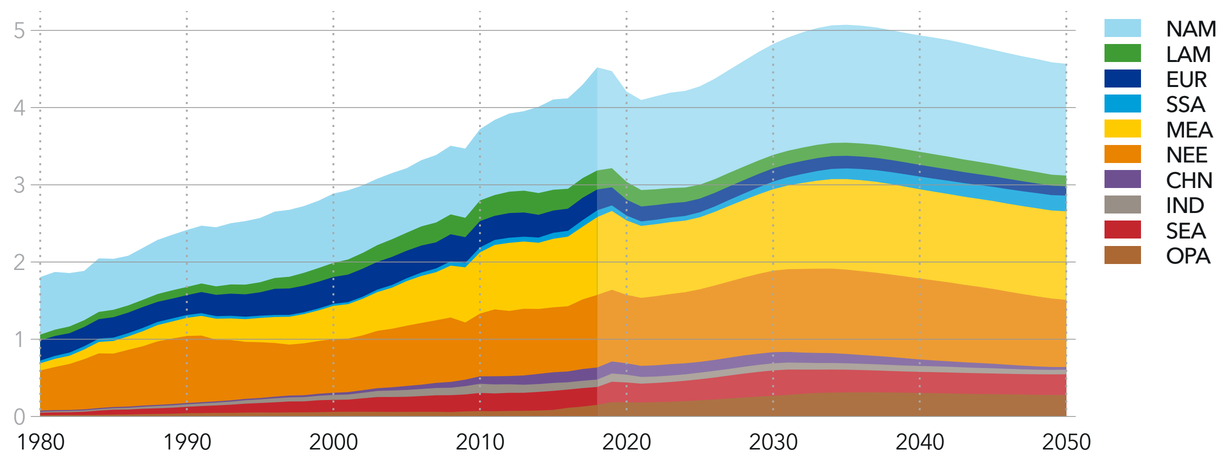
Greater China and the Indian Subcontinent will account for around 80% of imports from 2035. This necessitates significant increases in LNG regasification capacity, with Greater China set to increase more than fivefold to almost 400 Mt/yr in 2040, when it levels off. The Indian Subcontinent will see a rapid increase from around 40 Mt/yr in 2018 to more than 500 Mt/yr by 2050, while South East Asia will start from a similar point, increasing six-fold to 240 Mt/yr by 2050. Regasification capacity in Europe will increase moderately to 225 Mt/yr in the mid-2020s. OECD Pacific already has significant regasification infrastructure in place, with this set to increase marginally from around 335 Mt/yr in 2018 to 370 Mt/yr in 2025.

LNG is expected to remain the main driver behind global gas trade growth, but it faces the risk of prolonged overcapacity in the short term, as the build-up in new export capacity from past investment decisions outpaces slower than expected demand growth in the early 2020s.

FIGURE 2.13

Natural gas production by region

Units: Tm^3/yr

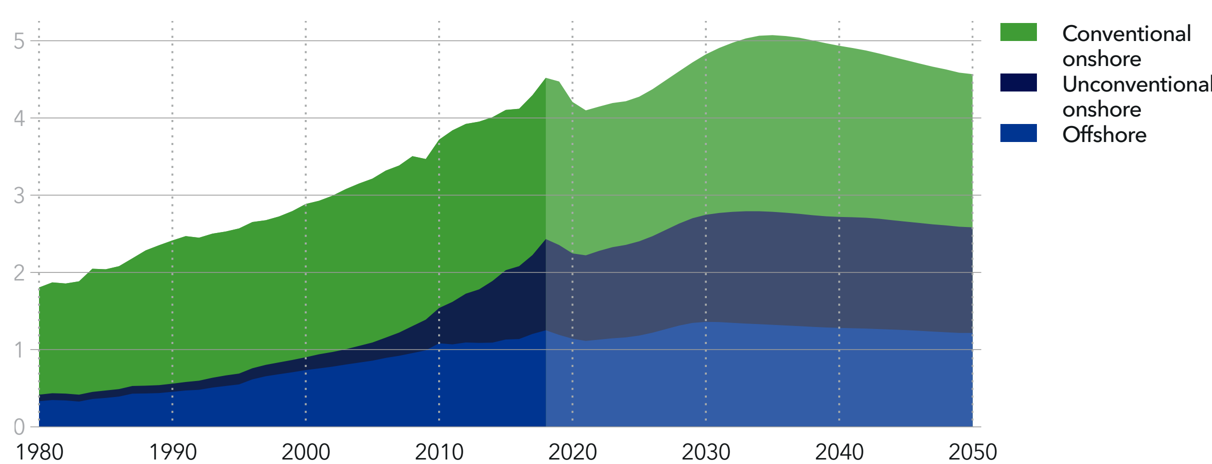


Includes natural gas liquids and refinery outputs. Historical data source: IEA WEB (2019)

FIGURE 2.14

World natural gas production by field type

Units: Tm^3/yr



Includes natural gas liquids from wells, but not refinery outputs. Historical data: Rystad (2019)

2.8.2 NORTH AMERICA TO DRIVE INVESTMENT IN LNG

Growth in LNG liquefication will outpace regasification, though both will grow significantly. Global capacity for liquefaction will more than triple by 2050, while regasification will more than double. North America will see the largest growth in liquefaction, accounting for 44% of global capacity by 2050. Middle East and North Africa will be the second largest, representing about 17% of global liquefaction capacity. On the regasification side, the Indian Subcontinent and Greater China will account for nearly half (47%) of the global regasification capacity expansion by mid-century.

In terms of investment, capex in LNG will increase dramatically in the mid-2020s, with North America accounting for three fifths of the around USD 250 billion (bn) set to be invested in both 2024 and 2025 (Figure 2.16). The region will account for a similar proportion of the more than USD 170bn in 2027 and USD 140bn in 2028, before global investment falls to USD 60bn, a little higher than in 2018. Part of this is that the capex required to increase LNG liquefication capacity is much higher than to increase regasification capacity.

2.9 EXPENDITURE SWITCHING FROM FOSSIL FUELS TO RENEWABLES AND GRID

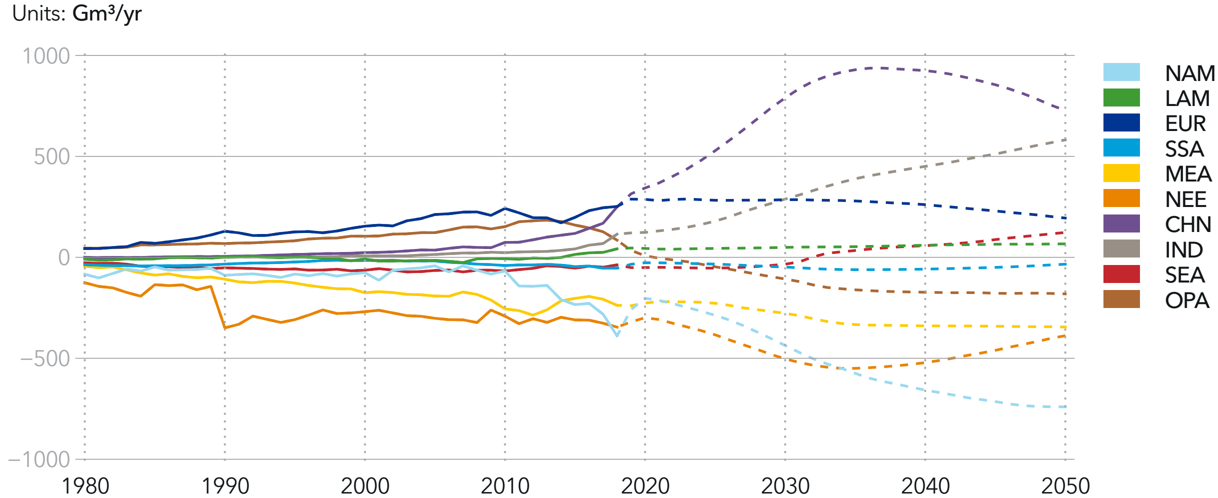
Fossil energy expenditure represented more than 80% of world energy expenditure in 2018, but this will decline to 44% in 2050, with non-fossil expenditure accounting for 34% and grid expenditure 22% in 2050 (Figure 2.17). Over this period, fossil energy expenditure will decline from USD 3.2 trillion (trn) to USD 1.95trn in 2050. Expenditure will be increasingly directed towards non-fossil energy, with this rising from USD 0.48trn in 2018 to USD 1.49trn in 2050, surpassing fossil fuel capex in the mid-2040s. Alongside, grid costs to facilitate the energy transition will become a significant share of world energy expenditure, increasing from USD 0.4trn/yr in 2018 to USD 0.95trn/yr in 2050.

Oil capex will lead a fall in upstream fossil-fuel expenditure, falling nine-fold from today to mid-century. Neither oil opex nor gas capex will decline by more than a quarter to 2050, while gas opex will remain stable. The proportion of world GDP spent on energy is roughly halved over the period – from 3% to 1.6%.

FIGURE 2.15

Net natural gas imports by region

Units: Gm^3/yr



Historical data source: IEA WEB (2019)

FIGURE 2.16

LNG CAPEX

Units: Billion USD/yr

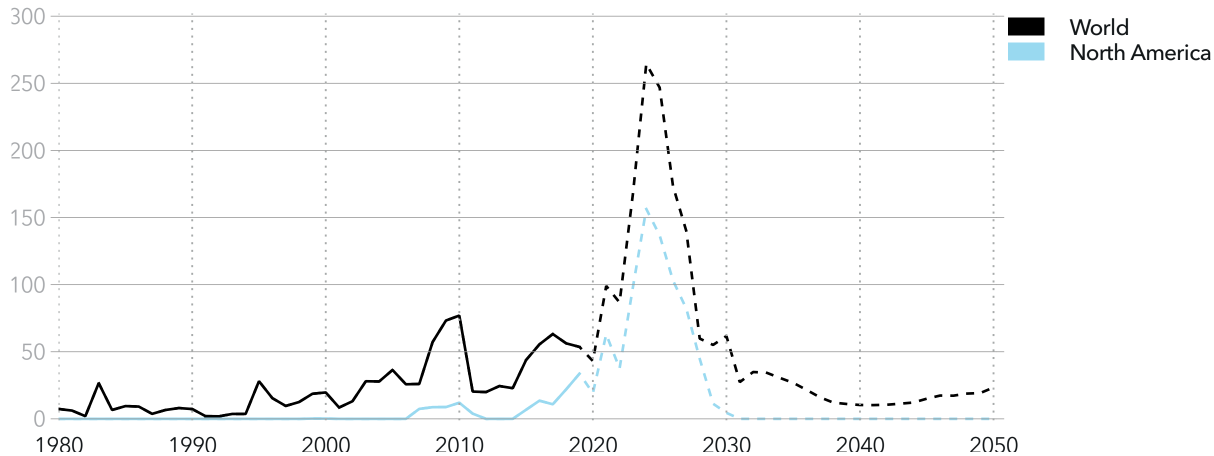
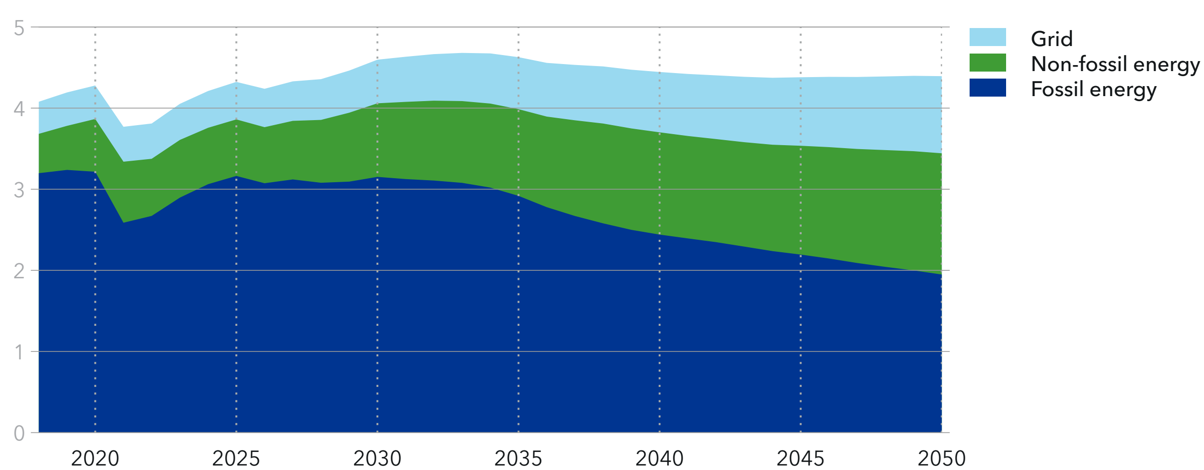


FIGURE 2.17

World energy expenditures by source

Units: Trillion USD/yr



CHAPTER 3

DECARBONIZING THE OIL AND GAS INDUSTRY

3 DECARBONIZING THE OIL AND GAS INDUSTRY

Growing awareness of the urgency and magnitude of the climate change challenge is putting mounting pressure on the oil and gas industry.

3.1 EMISSIONS TO REMAIN STUBBORNLY HIGH TO THE MID-2030s

Energy-related CO_2 emissions will be halved between 2018 and 2050 according our forecast, to around 17 $GtCO_2$/yr in mid-century. However, this long-term forecast hides the fact that emissions in 2035 will not have dropped below 30 $GtCO_2$/yr, remaining stubbornly high. Emissions will fall just 15% in the next 15 years, before then dropping 40% in the 15 years to 2050.

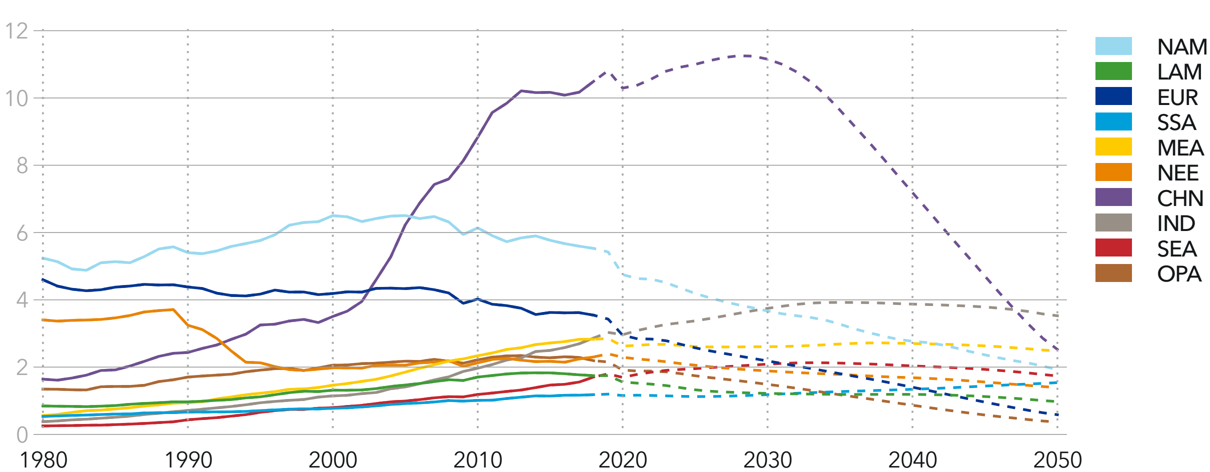
This masks significant regional variations (Figure 3.1). Greater China emitted 31% of the world's CO_2 emissions in 2018 with 10.5 $GtCO_2$. The region is followed by 5.5 $GtCO_2$ from North America and 3.5 $GtCO_2$ from Europe. Greater China's emissions will increase until 2030 according to our forecast, before undergoing a rapid decline up to 2050, with the decline driven by ambitious policies.

North America and Europe have already begun to reduce their CO_2 emissions, along with OECD Pacific. These declines are largely due to falling energy demand, growing use of renewable energy, natural gas replacing coal in power generation, and changes to the energy sources used in the transport sector. Europe will be the second-lowest carbon emitter after OECD Pacific by 2050.

FIGURE 3.1

Energy-related CO_2 emissions by region

Units: $GtCO_2$/yr



Latin America will also see steady reductions in emissions, starting from a relatively low level. The region's power generation sector, for example, is already dominated by hydropower and we forecast that non-fossil energy production will be more than 95% by 2050. However, Latin America will not see the same drops in oil demand from changes in transport as the other regions where we forecast that emissions will fall.

We forecast the Indian Subcontinent, South East Asia, and Sub-Saharan Africa to see higher emissions in 2050 than in 2018. Their trajectory is led by growing populations and the need to provide a secure, affordable supply of energy as energy demand grows.

North East Eurasia, and Middle East and North Africa will see moderate declines in emissions to 2050, as natural gas and oil maintain dominant shares of primary energy demand in these regions and coal use is marginalized.

3.2 PRESSURE IS MOUNTING

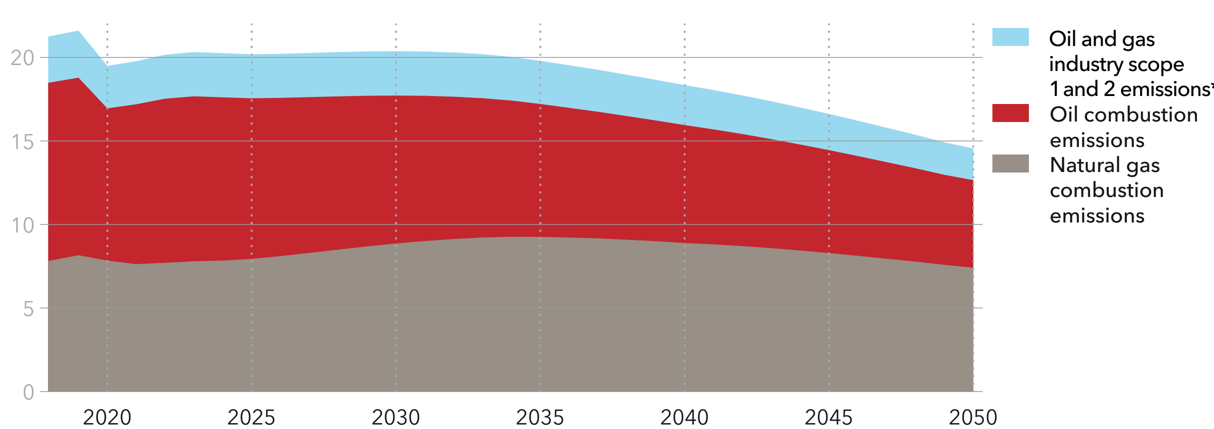
Even with peak demand for fossil fuels and peak emissions behind us, and flat energy demand through to 2050, the energy transition we forecast is still nowhere near fast enough to deliver on the Paris Agreement (see Section 1.2). Production and delivery of hydrocarbon products emitted 5.3 gigatonnes of equivalent carbon dioxide ($GtCO_2e$) in 2018, and combustion of these products an additional 16 $GtCO_2e$. By 2050, we project that total emissions across the oil and gas value chain – from exploration and production through to end use – will have dropped by 32% (Figure 3.2). The industry will need to decarbonize even more deeply than this to help achieve international emissions targets.

The oil and gas industry is under pressure to provide solutions that can decarbonize the use of its products, and ultimately to transition from hydrocarbon portfolios to cleaner energy. The longer-term success of the sector may hinge on its ability to drive proactively the necessary transition rather than passively react to societal pressure.

FIGURE 3.2

Oil and gas industry CO_2 emissions

Units: $GtCO_2$/yr



*Scope 1 and 2 emissions do not include the oil and gas industry's scope 1 and 2 emissions from own combustion of oil and gas. It is also assumed that the Scope 1 and 2 emissions shown in blue are 15% of the combustion emissions throughout the firecast period, which reflects the current level.

The industry recognizes that its license to operate in a carbon-constrained world depends on its ability to reduce its carbon footprint. Several large oil and gas companies have set corporate targets for carbon neutral exploration and production by 2050 or sooner (see Section 3.3.1), and a reduction in overall carbon intensity of their products by 50% or more by 2050. To reach these targets, the industry will need to realize a variety of technologies and solutions, from diversification into low-carbon energy solutions and development in electrification, batteries and renewables, to deployment of negative emissions technologies.

In 2050, the industry will broadly not be measured on carbon dioxide equivalent (CO_2e) emissions per barrel of oil or gas it has produced, as is the default today, but by lifecycle CO_2e emissions per barrel of oil or gas consumed. This includes so-called 'scope 3 emissions', including those associated with products and services purchased or produced, and therefore all emissions from combustion or use of oil and gas products. Decarbonizing gas consumption using carbon capture and storage (CCS) technology is the main lever through which the industry can achieve deep cuts in these emissions. CCS deployment is forecast to ramp up from less than 200 $MtCO_2$/yr captured and stored in 2030 to more than 2.1 $GtCO_2$/yr in 2050 (see Section 3.6).

Technology and solutions to deliver a faster energy transition exist, but policy will be essential to realizing and scaling them. In our survey of senior oil and gas professionals on the outlook for the sector in 2020[9], 73% of the more than 1,000 respondents said their company would only decarbonize if it makes financial sense. It seems governments and international organizations such as the European Union are taking note. The past 12 months have seen significant developments in decarbonization policy. Further, the content of COVID-19-related economic stimulation packages, the details of which are beginning to emerge, will be key in determining whether the pandemic will speed up or slow down the energy transition. Our modelling reflects this.

EMISSIONS ACCOUNTING STANDARDS: SCOPES 1, 2, AND 3

The Greenhouse Gas Protocol sets out Standards to measure and manage greenhouse gas (GHG) emissions[10]. First launched in 2001 – and later revised – these standards have been widely adopted by businesses and governments around the world, as the international standard for assessing and reporting GHG emissions.

These standards classify a company's emissions into three scopes:

- Scope 1 are direct emissions from company operations
- Scope 2 are indirect emissions, such as from purchased electricity, steam, heating and cooling
- Scope 3 are emissions through a company's entire value chain, both upstream and downstream, including emissions from the combustion of oil and gas products.

3.3 INDUSTRY-LED INITIATIVES TO REDUCE EMISSIONS

As the oil and gas industry seeks to maintain its license to operate in a carbon-constrained world, several oil and gas industry associations – including Oil & Gas UK[11] and the Norwegian Oil & Gas Association[12] – have published roadmaps for decarbonizing oil and gas production. These include medium-term emissions reduction targets (towards the 2030s) and longer-term targets (towards mid-century). Further, industry organizations in other sectors, such as the International Maritime Organization (IMO), are setting GHG emissions reduction targets, which will shape demand for clean energy in their respective industries.

3.3.1 IOCs SETTING OWN EMISSIONS TARGETS

Several oil and gas majors are already transforming themselves into broad-portfolio, lower-carbon energy companies, with interests in a diverse range of sources, carriers, and distribution models. As some have put it, many of the world's oil and gas giants are shifting from 'big oil' to 'big energy'.

Each of the six largest oil and gas companies in Europe – BP, Eni, Equinor, Repsol, Shell and Total – has now made a public commitment to work towards the target of net-zero or near net-zero carbon emissions by 2050.[13] A growing list of operators is following suit.

Europe-headquartered oil and gas companies are leading the sector's decarbonization efforts. In contrast to companies in other regions, the European oil and gas industry faces pressure to rapidly reduce emissions from two angles: shifting shareholder sentiment, and the European Green Deal (and/or other national targets) coming into legislation.

On average, the production of oil and gas accounts for some 4% of the industry's greenhouse gas (CO_2e) emissions from production through to end-use.[14] It is the consumption of hydrocarbons – the point at which hydrocarbons are burned to create energy – where most of the carbon is emitted into the atmosphere. Despite this, current emissions reduction targets set by the industry focus primarily on hydrocarbon production. This is due to growing motivation for the industry to demonstrate quick action. We therefore expect emissions reductions from oil and gas production to dominate the industry's decarbonization agenda in the shorter term, with solutions scaled rapidly over the course of the 2020s.

3.3.2 REDUCING EMISSIONS FROM OIL AND GAS PRODUCTION

Many oil and gas companies are prioritizing measures to minimize emissions from core oil and gas operations. As of today,15% of global energy-related GHG emissions comes from the process of getting oil and gas out of the ground and to consumers.[15]

In the short term, reducing methane leaks is an essential way for the industry to bring down GHG emissions. Coincidentally, because methane has a market value, it is often cost effective to implement measures to reduce or eliminate methane leaks and fugitive emissions.

There are also ample, cost-effective opportunities to bring down the emissions intensity of delivered oil and gas by minimizing flaring of associated gas and venting of CO_2. Integrating renewables and low-carbon electricity into new upstream and liquefied natural gas (LNG) developments also provides a path to reducing emissions from oil and gas production. In the following sections, we consider some of the main ways that oil and gas companies are decarbonizing their operations.

3.3.3 PLATFORM ELECTRIFICATION

Around 5% of offshore wellhead production globally is used to power platforms, according to a 2019 study published by Wood Mackenzie.[16] Based on our modelling of natural gas production, this resulted in 124 $MtCO_2$ emissions in 2018. As the cost of variable renewables rapidly declines, upstream oil and gas operators are turning to hydrocarbon and renewable technology integration as an emissions-free alternative. A report published by the UK Oil & Gas Authority in 2019 concludes that technology for platform electrification is proven and could enable near-term emissions reductions for the industry.[17] There are commercial benefits as well. Hydrocarbons not used to power production can be taken to market.

Projects already in operation are delivering renewable electricity from shore to offshore platforms by cable, mainly in Europe. Installations in the North Sea include Troll A, the first platform on the Norwegian Continental Shelf to be electrified from shore in 1996, and the Gjøa field, which was electrified from the outset. In the Netherlands, Neptune's Q13a-A platform is electrified from shore, saving approximately 14,000 tCO_2/yr in emissions. Several operators in the UK sector are considering supplying installations with renewable power via subsea cables. These include BP's Central North Sea and West of Shetland developments.

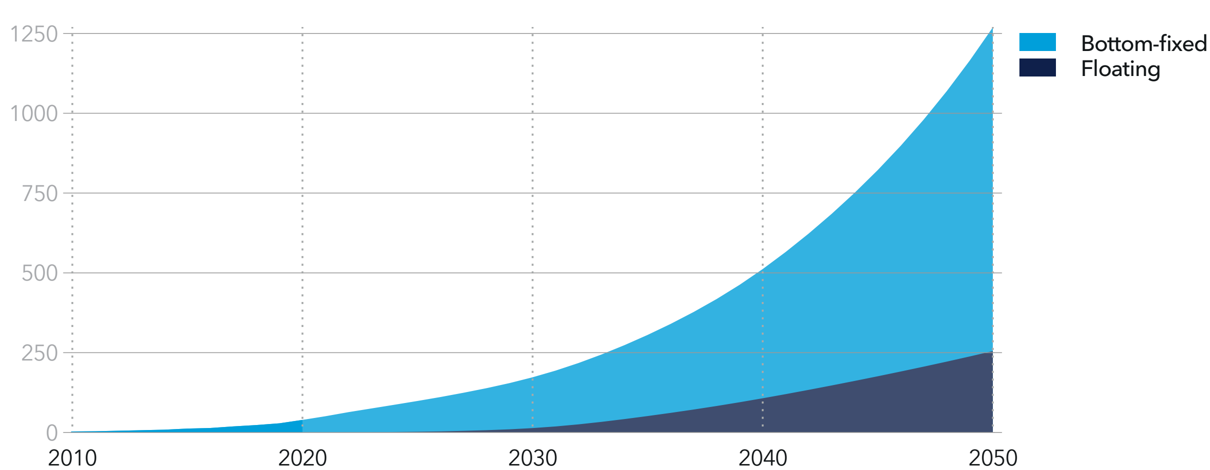
Platform electrification developments are progressing elsewhere. China's CNOOC plans to build two fixed, high-voltage AC power platforms powered by an onshore grid. The project, due to start up in 2021, will be the country's first example of platform electrification. In the UAE, ADNOC and Abu Dhabi Power Corporation (ADPower) jointly announced the region's first high-voltage direct current (HVDC) subsea transmission system, connecting ADNOC's offshore production facilities to ADPower's onshore electricity grid. The abundance of solar energy and long-life offshore oil and gas assets in the Middle East offer strong potential for the region.

Projects to directly power offshore oil and gas installations from wind farms are also in development. In April 2020, Equinor received approval from the Norwegian government for Tampen Hywind, which will be the world's first

FIGURE 3.3

World installed offshore wind capacity

Units: GW



Historical data source: IRENA (2020)

floating wind farm to power offshore oil and gas platforms. It will reduce the use of gas-turbine power for the Snorre and Gullfaks offshore fields, while offsetting 200,000 tCO_2/yr of emissions.

Our model forecasts significant scaling of global installed offshore wind capacity, from 23 gigawatts (GW) in 2018 to 1,269 GW in 2050. Fixed installations will account for practically all offshore wind capacity over the next five years. From the mid-2020s, floating offshore wind installations will be introduced to the market and begin to scale, accounting for 20% of installed capacity in 2050 (Figure 3.3). The rapid increase in offshore wind's share of energy supply, and the associated decrease in the cost of this technology, is likely to make wind-powered oil and gas installations increasingly viable, even in deep water.

3.3.4 REDUCING FLARING AND VENTING

The oil and gas industry emitted more than 81 $MtCO_2e$ of methane in 2019, according to estimates from the 2020 Methane Tracker, run by the International Energy Agency (IEA).[18] Of this, 68% was from venting; 28% from fugitive losses; and 4% from incomplete flaring. Natural gas that is not flared can leak into the atmosphere as methane, a more potent GHG than CO_2.

Data from the World Bank's Global Gas Flaring Reduction Partnership suggests that more than 145 billion cubic metres per year (Gm3/yr) of gas was flared globally in 2018, with five countries – Algeria, Iran, Iraq, Russia, and the US – responsible for more than 50%. In total, flaring resulted in around 275 $MtCO_2e$ of emissions.

Flaring activity reached a peak in the early 2000s and had fallen by 20% by 2010. However, the shale gas boom in the US, where flaring activity has quadrupled in the past decade, has resulted in no further reduction in emissions from flaring in the past 10 years.[19]

The US is producing so much gas from the Permian Basin that prices turned negative several times in 2019. A lack of gathering infrastructure and pipeline capacity effectively makes the natural gas worthless, and it is more economical to vent or flare it away than transport it (at a loss) to a buyer.[20] Flaring is often required to be limited to a short period after a new well is drilled or for upsets to maintain safe operating conditions, but the practice has currently reached record high levels in the Permian Basin.

A broad range of methane emissions abatement technologies and measures are available. The IEA, in its Methane Tracker, estimates that around 75% of these emissions could be avoided, and that 40% could be avoided with measures that would have no net cost if captured and commercialized.

3.3.5 METHANE LEAK DETECTION

Significant improvements in satellite technology are now revealing new methane leak hotspots around the world, not just from venting during production but from compressor stations during transportation.

In 2019, methane leaks from the oil and gas industry were detected for the first time by satellites according to Canadian company GHGSat, which reported detecting an "anomalously large methane plume" from a gas facility and pipeline near a mud volcano it was monitoring in Turkmenistan.[21] The leak was plugged after the operator was notified. GHGSat claims this is the equivalent of taking a million cars off the road. Later in the year, European Space Agency satellites revealed significant methane leaks from a pipeline transporting gas from Russia to Europe.

A study[22] published in Nature magazine indicates that the amount of methane leaked into the atmosphere by the fossil fuel industry is up to 40% greater than recent estimates, and several oil and gas majors are now increasing investment in aerial technology to detect and address leaks.

In 2019, BP announced that it had successfully completed a pilot project to test innovative ways of remotely monitoring methane emissions on its offshore assets in the North Sea, by combining advanced sensor technology originally designed by NASA for the Mars Curiosity Rover with a fixed-wing remote piloted drone.[23] The company's technology investment arm, BP Ventures, has since invested in cloud-based geospatial analytics software company Satelytics as part of its strategy to deploy a suite of complementary methane detecting techniques across new and existing facilities.

ExxonMobil is field-testing methane methods including satellites and aerial surveillance with drones, helicopters, and planes, and Shell has signed a deal with GHGSat with the aim of reducing the methane leakage rate down to 0.2% or less by 2025 at its sites around the world. In 2020, a consortium of oil and gas organizations – including BP, EDF, Eni, Equinor, Shell, Total and Wintershall Dea – sent policy recommendations to the EU to standardize methane emissions data collection using satellite technology by 2023.

Three industry organizations – the Oil and Gas Climate Initiative (OGCI), the International Association of Oil & Gas Producers (IOGP) and IPIECA – have taken steps to initiate development of a best practice guideline on the detection, monitoring and reporting of methane emissions.

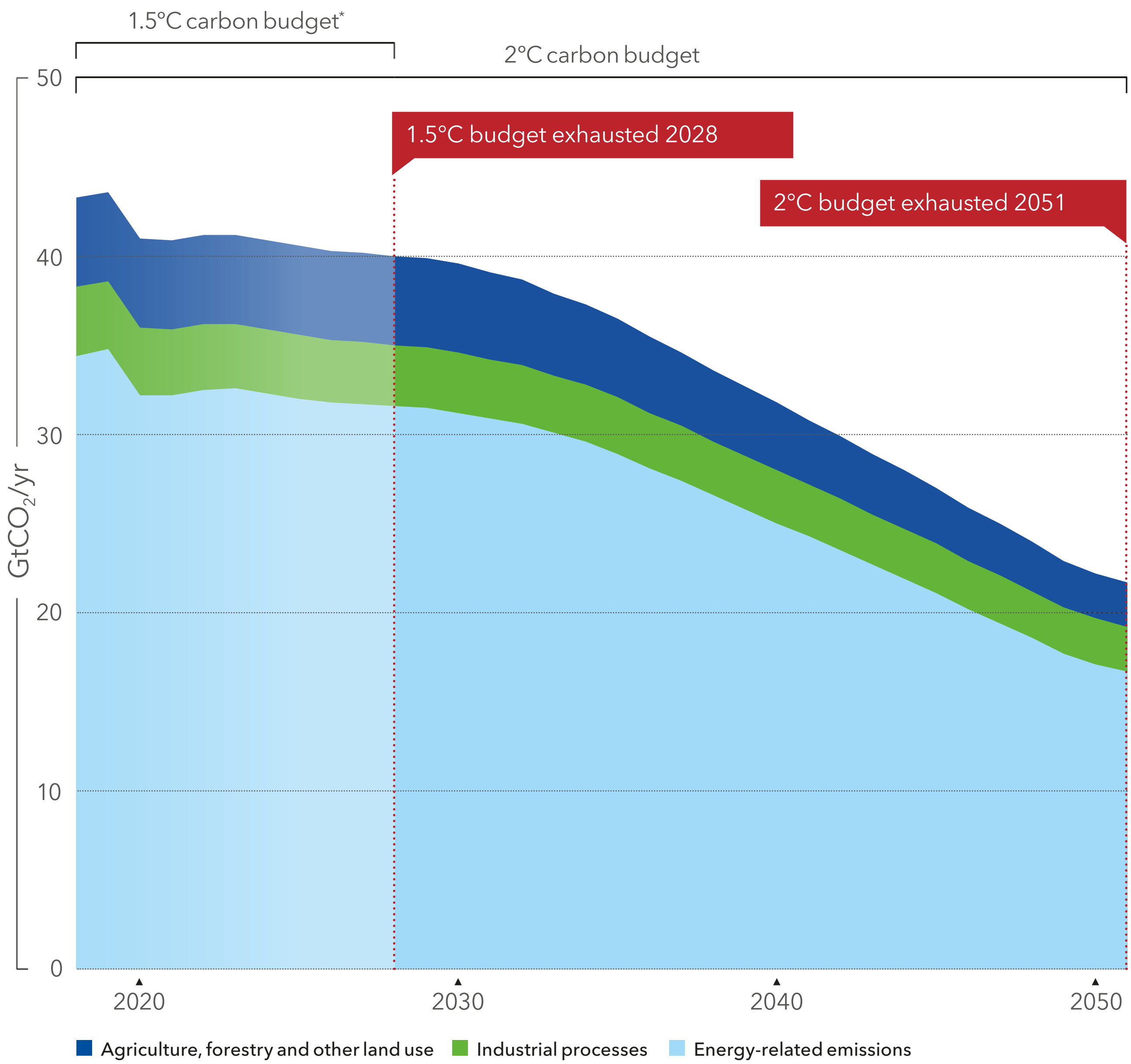
3.4 POLICY IS KEY TO DECARBONIZATION

Energy and climate policies, both national and regional, reflect a mosaic of international commitments. They are led by political priorities to ensure secure supplies of affordable energy, alongside decarbonizing. They are influenced by energy resources available, societal pressures including rising concern over climate change, and calls for cleaner energy. Policy is key not just in setting out the path to decarbonize, but also in deciding how quickly regions and the world move down that path.

The quicker that governments incentivize industry to adopt technology, the quicker the technology progresses along the cost-learning curve and becomes independently financially viable. Take, for example, the high acceleration in the decade to 2020 of solar power and wind technologies globally. This would not have happened without the large incentives offered by certain countries, such as Germany in the Energiewende throughout the 2010s. In line with this, policy support for hydrogen, CCS technology and solutions for hard-to-abate sectors needs urgent acceleration if regions, and the world, are to meet emissions targets. While governments can bring incentives to the table, industry needs to be enabling technology innovation to reduce the cost of implementing technologies.

Policies from the Paris Agreement to the local level are supporting transitions to cleaner energy, but some policies stand out as having a crucial effect on the oil and gas industry and its role in the energy transition. Some of these will affect demand for existing oil and gas, and will drive companies to reduce their carbon footprint; others may completely transform the oil and gas industry. We examine these polices in the following sections.

CARBON EMISSIONS AND CARBON BUDGETS



*The Paris Agreement sets out that the world should seek to limit global warming to well below 2°C and to pursue efforts to limit global warming to 1.5°C. Almost all countries have signed the international agreement.

3.4.1 NET-ZERO IN EUROPE PUSHING DECARBONIZATION TO EVERY SECTOR

The EU and several countries in Europe have since 2019 been setting targets for net-zero carbon emissions by 2050. Under these targets, emissions will need to be reduced while those that remain must be captured or offset. Reaching carbon neutrality will inevitably impact demand for oil and gas in Europe, particularly for applications that have emissions that are difficult to abate.

One effect of the net-zero targets so far in Europe is greater and more immediate recognition that a hybrid energy future will emerge. This is not just a future that accommodates gas and electricity, or efficiencies to reduce energy demand, but all the above and more in order to reach net zero. The targets have led governments to embrace everything they can to decarbonize quickly.

The prevailing view among oil and gas professionals is that the industry will only decarbonize if it makes financial sense for them[9]. Subsequent policies, from investment to carbon price, will play a key part in this. On the investment (or divestment) side, the European Investment Bank took the decision in November 2019 to end lending for all unabated fossil-fuel projects by the end of 2021. This is just one among many decisions favouring investment in renewables over fossil-fuel projects.

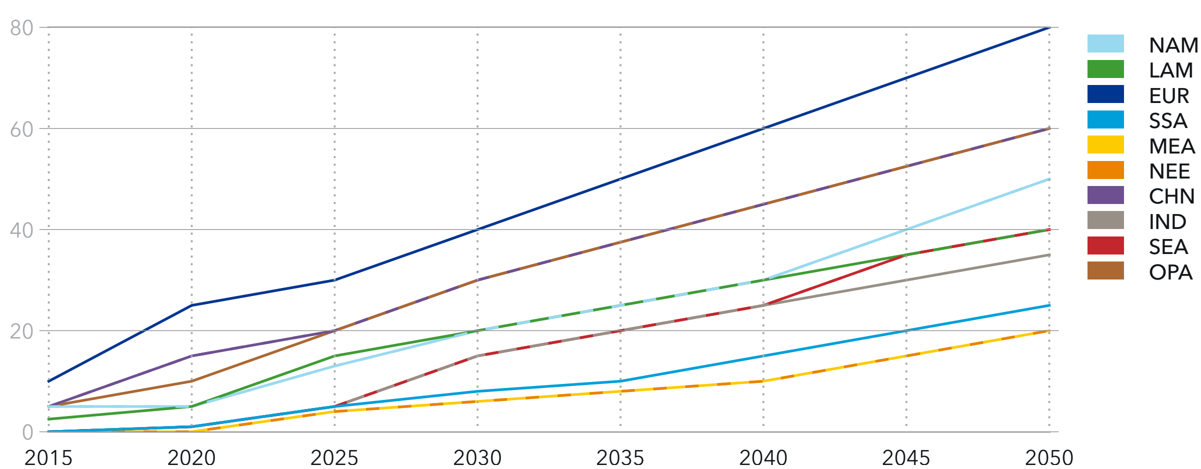
A key parameter is the assumed carbon price (Figure 3.4), with the amount of carbon captured via CCS being very sensitive to any changes in this parameter. Europe will lead the way in raising the carbon price on the path to 2050, creating much of the early demand needed to scale CCS. The EU is also considering a 'CO_2 border tax', which would extend a price on carbon to imported products. The aim is to prevent stakeholders from exporting their carbon emissions, such as by moving production out of the region.[25]

Based on sensitivity studies of our model, we forecast that if predicted carbon prices for 2050 (USD 80 in Europe, USD 60 in Greater China and OECD Pacific, and USD 50 in North America) were brought forward, then the level of CCS deployment in 2050 (2.2 $GtCO_2$/yr), following the scaling of CCS in the 2040s, would be brought forward along with it.

FIGURE 3.4

Carbon price by region

Units: USD/tCO_2



Hydrogen plays a key part in the story too, and is in many ways symbiotic with the scaling of CCS. The EU hydrogen strategy published in July 2020 (see Section 3.5.2) aims to enable hydrogen to scale-up to fulfil the targets of the European Green Deal, and follows similar strategies in Germany and the UK. The strategy puts priority on green hydrogen. The EU Strategy for Energy System Integration, published together with the EU hydrogen strategy, does, however, put limited reliance on CCS in its decarbonization ambition, stating that 80% of gaseous fuels should be of renewable origin in 2050. Our forecast shows a different picture to both of these strategies, predicting that final energy demand for gas in Europe in 2050 will be split roughly equally between natural gas and hydrogen (including both blue and green).

In short, net-zero targets have within a year of coming into force given decarbonization efforts in Europe a serious kick-start, not just to reduce emissions, but to look long term at how all sectors can decarbonize and how all technologies can contribute. Other countries, such as Japan, South Korea, and Australia in OECD Pacific, are shifting towards setting net-zero targets for 2050, but they are yet to fully put these targets in place – which, as Europe has shown, is when things really start moving.

3.4.2 DIRECT INTERVENTION, AS CHINA DASHES FOR GAS

Greater China's 31% share of world energy-related emissions of CO_2 in 2018 makes its emissions reduction trajectory vital to the global energy transition. The region's energy system, dominated by China's figures, also stands out for the continued rise in energy-related CO_2 emissions that our model projects over the next decade before a steep reduction is achieved. This reflects China's 13th Five-Year Plan (2016–2020) aiming for emissions to peak by 2030 and the carbon intensity of energy supply to be 60-65% less than in 2005.

To achieve these reductions, China is focusing on natural gas in the nearer term, the vast majority of which will come from imports. Manufacturing will lead natural gas demand. Supply to this sector in Greater China has already doubled between 2016 and 2018. It is set to double again to more than 10 exajoules (EJ) in 2035, just under half of the region's total final energy demand from natural gas.

China's dash for gas follows government targets for natural gas to supply 15% of the country's energy mix by 2030. We project that the share of natural gas in China's energy mix will grow from 10% in 2018 to 21% in 2050, almost doubling its gas consumption in real terms (Figure 3.5).

EUROPEAN GREEN DEAL

The new European Green Deal[26] aims to transform the EU into a sustainable economy, while accelerating its decarbonization trajectory. It represents a considerable increase in ambition from existing policies, namely, to reduce GHG emissions in 2030 by 50% to 55% from 1990 levels (existing policies aim for 40% reduction from 1990 levels). The Green Deal also targets net-zero GHG emissions by 2050 (existing policies aim for 60% reduction from 1990 levels).

The deal provides an unprecedented roadmap for coordinated regional climate action and will require many new policies and technical details to be drafted. When the plan was unveiled in late December 2019, the President of the European Commission, Ursula von der Leyen, stated that, should it succeed, it would rightly be called "Europe's Man on the Moon" moment. It brands the new Commission with a clear green profile, but to turn plans into action requires approval and support from all the EU member states.

This compares to a decline in coal use from 59% to 12% of primary energy over the same period. Notably, China's reliance on fossil fuels for electricity generation is set to drop from 70% to 6% during the forecast period.

China also aims to substantially increase the share of renewables in power generation, principally to clean up air pollution under its blue skies policy, as well as to cut carbon emissions. Greater China will account for more than 25% of global renewable energy production in 2050. On the demand side, electricity will account for more than half of the region's final energy demand at mid-century, up from just under a quarter in 2018.

We forecast large-scale introduction of CCS and hydrogen in the 2040s. Greater China will lag Europe in using hydrogen for energy in the global hydrogen scale-up from the mid-2030s, but will move into first place from about 2045 to produce twice as much as Europe in 2050. This example illustrates how policy in one region can drive transitions in another.

The policy drive in Europe is set to reduce the cost of CCS, in order to be economical according to the carbon price in China.

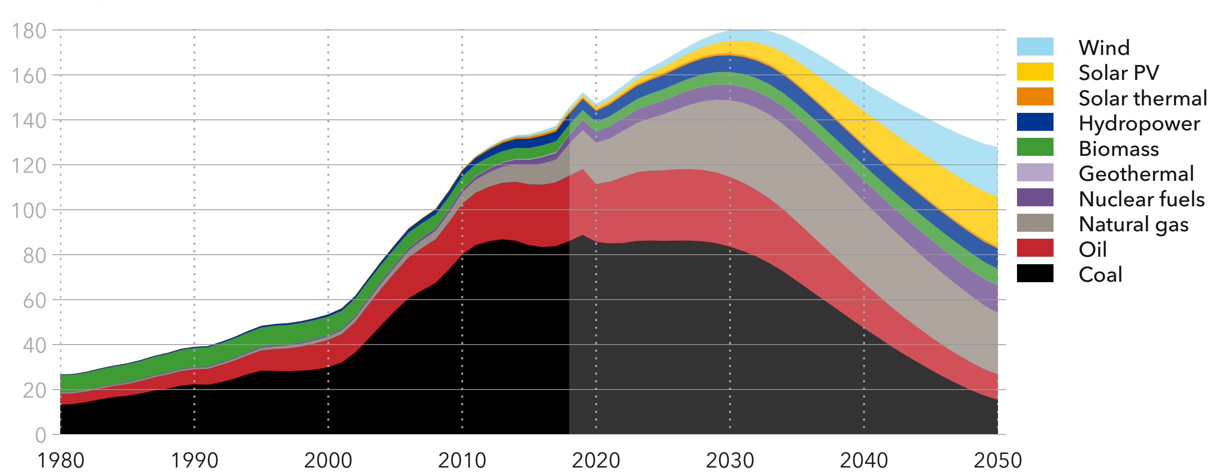
We forecast an average carbon price of USD 60 per tonne of CO_2 (tCO_2) in Greater China in 2050 (second only to Europe). This drives, in part, tenfold growth in the region's CCS capacity after 2040, reaching 892 $MtCO_2$/yr in mid-century. This increase will be greater than in any other region and equates to 35% of Greater China's total CO_2 emissions in 2050. China has one large-scale CCS facility already in operation, two in construction, and five in early development.

China's 14th Five Year Plan (2021–2025) will set the framework for what happens next with energy policy, but the increasing role of gas and variable renewables is assured. The policy approach in China differs significantly from other countries and regions. With state-owned companies throughout the value chain and a system of state intervention, it can direct rather than incentivize, regulate, and influence stakeholders and markets to decarbonize.

FIGURE 3.5

Greater China primary energy consumption by source

Units: EJ/yr



Historical data source: IEA WEB (2019)

3.4.3 NORTH AMERICA A PATCHWORK OF POLICY, IN WHICH FINANCIAL INCENTIVES WILL BE KEY

US federal policy overall is currently in flux, but a patchwork of state alliances and unilateral commitments are driving the energy transition. In the short term, the current Administration has leaned away from any regulations limiting GHGs. However, 22 US states have set GHG emission standards. For example, California has goals for annual emissions in 2020 to be no higher than in 1990, and 80% lower in 2050. Further, states are making investment decisions anticipating significant carbon-emission costs in the future.

Medium-term US energy and economic policy priorities at the federal level are subject to uncertainty as elections approach in November 2020. State governments participating in the US Climate Alliance (USCA) are meanwhile pursuing renewables and decarbonization goals and making commitments towards the Paris Agreement. Eight of USCA's 25 member states are targeting zero-carbon power generation by 2040.

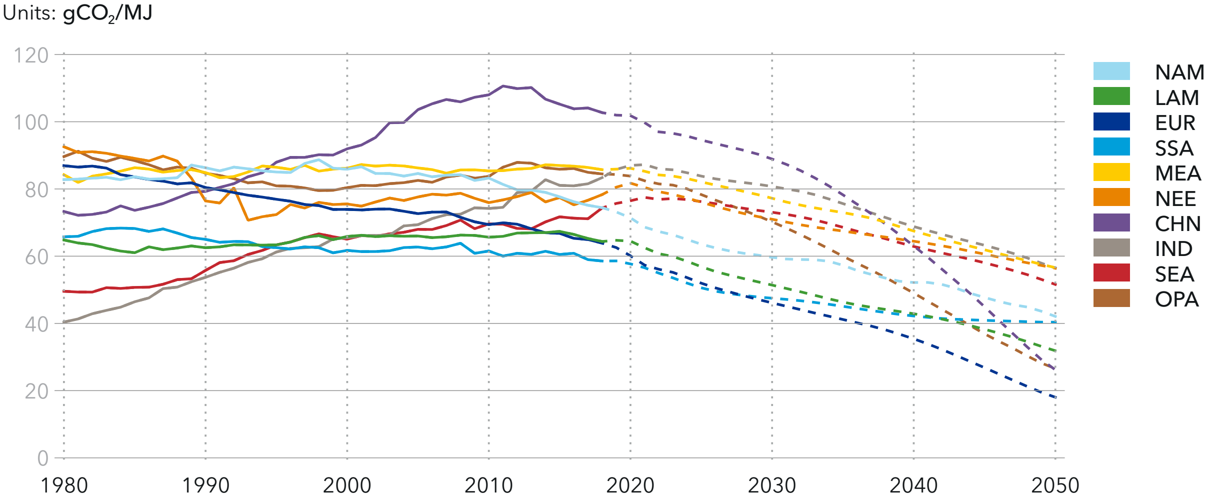
Emissions reductions in North America will be chiefly driven by improvements in energy efficiency (particularly in transport) and replacement of coal with natural gas. Energy efficiency gains, while continuing to improve across the entire energy value chain – from grid management through to appliances – will be primarily driven by the timeline for implementing vehicle emissions standards to 2025.

We expect similar trends in Canada, where federal policy is phasing out coal for electricity generation by 2030 and replacing it with natural gas and renewables. The country aims to produce 90% of electricity from non-CO_2-emitting sources by 2030. It also aims to reduce methane emissions from oil and gas by 40% to 45% by 2025 compared with levels in 2012. The federal carbon tax introduced in 2018 is an important instrument to drive emission reductions in Canada. It started at CAD 10 per tCO_2 in 2018 with a plan to raise the tax-level by CAD 10 per year to reach CAD 50 per tCO_2 in 2022.

FIGURE 3.6

Emission intensity of final energy demand by region

Units: gCO_2/MJ



Stakeholders within North America are offering significant financial incentives, tax breaks and investment in CCS and to a lesser degree hydrogen – the technologies that will reduce emissions in hard-to-abate sectors. There are 10 large-scale CCS facilities in operation in the US, and four in Canada. The Global CCS Institute reports that most of the facilities that have come into operation in the US since 2011 have benefitted from a combination of the 45Q tax credit and revenues from CO_2-Enhanced Oil Recovery (CO_2-EOR), which have placed a value on capturing CO_2 emissions. The 45Q tax credit provides capture operators with credits for each tCO_2 stored or utilized for CO_2-EOR, which can be used to reduce the capture operator's tax liability. It was introduced in 2008 and amended in 2018, to increase the tax credits to USD 50per tCO_2 for storage and USD 35 per tCO_2 for CO_2-EOR.

The California Low Carbon Fuel Standard (LCFS) provides another strong financial incentive for CCS. California has primacy to regulate GHG emissions under the Clean Air Act. In 2018 it amended its LCFS to allow CCS projects to qualify to generate credits. These changes came into effect in 2019. To qualify, the CCS project needs to be associated with the production of a transport fuel that is sold in California, except for direct air capture projects that can be located anywhere. LCFS credits are currently trading at around USD 200 per tCO_2.

North American states are also exploring how hydrogen can help decarbonize the energy system. Utah launched the Advanced Clean Energy Systems project in 2019, with plans to construct a renewables-to-hydrogen energy-storage system in which renewably generated hydrogen is stored in underground salt caverns. California is looking to meet its decarbonization 2050 targets through a phased strategy that includes, in part, the blending of hydrogen into natural gas pipelines.

While these incentives will drive the adoption of hydrogen and CCS, they have not yet had the same effect as net-zero policies in Europe on IOCs. That is, North American IOCs are setting long-term targets for percentage reductions in net GHG emissions to a lesser degree than those headquartered in Europe.[27] They are largely reducing emissions from production rather than looking to the value chain.

3.4.4 REGIONS BALANCING DECARBONIZATION WITH SECURE, AFFORDABLE ENERGY

Emissions will not decline during the forecast period on the Indian Subcontinent or in the Middle East and North Africa, South East Asia, and Sub-Saharan Africa. These are also the regions set to see the greatest increases in energy demand during the period. These regions will have to wrestle with the need to provide an increasing supply of affordable, reliable energy while also seeking to decarbonize. Making the policy picture substantially different to Europe, Greater China, North America and OECD Pacific.

For the Indian Subcontinent, Middle East and North Africa, and South East Asia, fossil fuels will continue to dominate energy demand, accounting for more than 60% of primary energy demand in these regions in 2050, compared to 54% globally. They are looking to reduce carbon intensity, switching from coal to natural gas. All will see growth in renewables.

By 2050, the Indian Subcontinent will have 500 million more people and GDP will have grown fourfold. This will drive an 80% rise in energy demand between now and 2050. We see annual CO_2 emissions rising steadily to plateau in the early 2030s, as final energy demand keeps growing. Despite the enormous two- and three-wheeler vehicle fleet becoming almost all-electric in the region before 2040, in addition to rapid growth in renewables, the dependence on fossil fuels will see it become the world's largest CO_2 emitter by mid-century.

India, the dominant player in the region, has pledged to reduce the GHG emission intensity of its GDP by a third (33-35%) from 2005 levels and to raise the share of non-fossil power in total generation capacity to 40% in 2030. However, the latter commitment is conditional on the necessary international finance being provided by 2030 – a clear sign that it is not just the intention that will direct the energy transition in the region, but the availability of finance and support to decarbonize while meeting increasing energy demand. The issue of air pollution may yet lead to changes in policy – and lower CO_2 emissions – on the Indian Subcontinent. Significant societal pressure, and the cost of pollution to human health, are increasing pressure for cleaner energy policies.

Member states of the Association of Southeast Asian Nations (ASEAN) have committed to a combined unconditional emissions target of nearly 3.3 $GtCO_2e$ by 2030, which equates to an 11% reduction compared with business as usual. All these states have ratified the Paris Agreement, but there are no regional reduction targets for 2050.

Oil and gas production in South East Asia is dominated by national oil companies (NOCs) and government policy and targets are being rolled down to NOCs. In Thailand, for example, PTTEP is targeting a reduction of 25% in carbon-emission intensity by 2030, compared with 2012. These figures appear to be based largely on contributions from downstream processing, and power and transport fuel requirements, rather than being related to upstream exploration and production. Key policies introduced to mitigate methane emissions include eliminating continuous flaring, remote leak detection, and venting-reduction projects.

Natural gas is and will continue to be a key element of the region's energy policy. However, due to increasing demand, the region will no longer be a net gas exporter from 2030. Countries in South East Asia are pursuing various policy initiatives, such as the Trans-ASEAN Gas Pipeline, to increase interconnectedness and reduce future dependence on imported gas. Of the countries in the region, only Singapore has currently implemented a carbon pricing scheme (USD 5 per tCO_2e from 2019).

For Middle East and North Africa, the region will see little change in its final energy demand for oil and gas during the forecast period. Rapidly growing renewables, particularly solar, will simply make up for increased energy demand. We consider the reasons for this in Section 3.4.5.

Sub-Saharan Africa differs from the other three regions, in that much of its primary energy supply will come from biomass, accounting for 43% of primary energy demand in 2050. In turn, Sub-Saharan Africa will account for 34% of the world primary energy demand for biomass in 2050. This offers significant potential for negative emissions in the longer term when combined with CCS, but we do not expect this during the forecast period. The modest increase in emissions though the forecast period will come from increased oil demand from a growing transport sector.

3.4.5 HARD TO LET GO WHEN BENEFITING FROM THE STATUS QUO, BUT THERE IS A WAY

Fossil fuels will provide more than 70% of primary energy supply in North East Eurasia and Middle East and North Africa in 2050. This compares with 54% globally. They are also set to be the cheapest oil and gas producers. One result of this is that the energy intensity of countries in these regions is set to remain high.

Russian energy policy, for example, has focused on increasing gas exports to Europe and oil exports to Asia, while decarbonization has only been a factor in production. The Russian economy's dependence on oil and gas remains important, with oil and gas-related revenues accounting for 46% of total federal income in 2018[28]. State reliance on oil and gas revenues is a strong theme across these regions, particularly since it is here where oil production may be at its cheapest.

Despite Paris Agreement emission limits, many North East Eurasia and Middle East and North Africa nations are likely to continue to focus energy policies on developing and exporting hydrocarbons.

Mirroring these trends, some oil and gas companies globally are eager to extract and sell their oil and gas reserves as soon as possible, anticipating an acceleration in the energy transition.[29] Where there are IOCs transforming to broader energy companies, there are smaller operators becoming lean and focused on getting oil and gas out of the ground – albeit with measures to reduce methane and CO_2 emissions from production.

On the other side of this, some countries are anticipating likely shifts in demand towards decarbonized fuels, looking to hydrogen to continue to source income from hydrocarbons. Australia is a leading example, looking to exports of blue hydrogen from coal, along with plans for significant hydrogen production from renewables in the longer term. This extends to the company level, Russian gas company Gazprom, for example, is looking at how to develop hydrogen from its gas in order to export to Europe. This approach does, however, rely on policies elsewhere increasing demand for decarbonized gas. The development of international agreements on value-chain emissions and scope-3 accounting regimes will likely advance this trend.

3.5 HYDROGEN COULD BE TRANSFORMATIVE IN THE ENERGY TRANSITION

3.5.1 HYDROGEN KEY TO DECARBONIZING GAS

Natural gas will become the world's largest energy source in the mid-2020s. Producing hydrogen from natural gas with CCS has the potential to decarbonize this gas, which will be key as countries look to reduce their emissions. However, this happens to a limited extent in our Outlook.

We forecast that 1.3% of natural gas supply will be decarbonized through CCS before end use in 2030 (e.g. for production of electricity and hydrogen), and only 13% by 2050.

Hydrogen will only partly realize its potential to become the low-carbon fuel of the future to complement renewables before 2050. Future policy changes could have a significant impact though. In our 2019 Energy Transition Outlook, we forecast energy demand for hydrogen as an energy carrier to be 7 EJ/yr in 2050. Within a year, many policies and initiatives have been passed in hydrogen's favour, leading us to more than triple our forecast to 24 EJ of demand for hydrogen by 2050, but not starting to scale until after 2035.

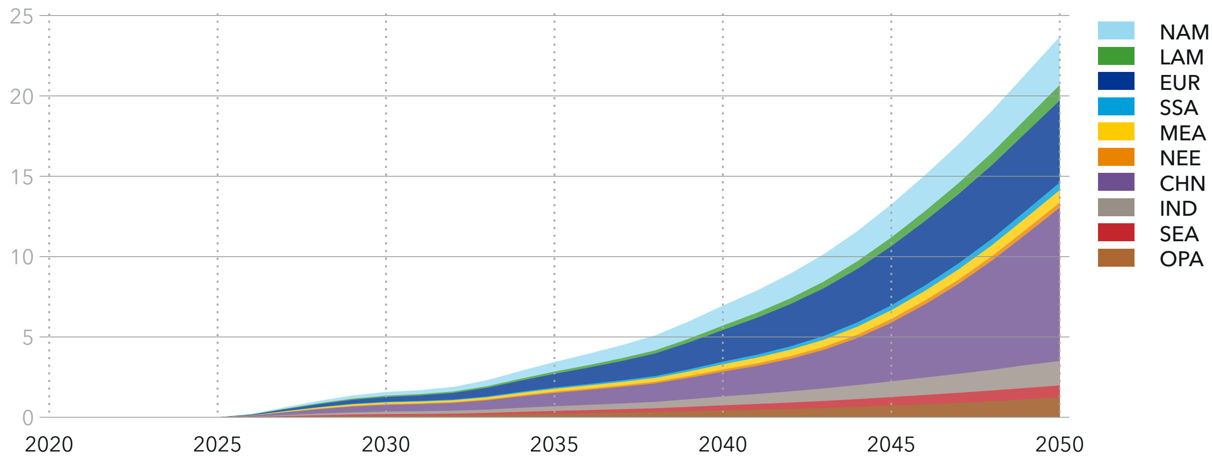
These policies include net-zero targets in Europe and incentives in terms of a carbon price or carbon credits. More specifically, many countries have published national hydrogen strategies in recent years, including Australia, Germany, Japan, and Norway. The EU is the latest to join this, publishing its hydrogen strategy in July 2020. Meanwhile, hydrogen has surged up the priority list at many oil and gas organizations as part of broader decarbonization efforts. Around half (52%) of the senior oil and gas professionals we surveyed towards the end of 2019 said that they expect hydrogen to be a significant part of the energy mix within just 10 years.[30]

CCS technology enables natural gas producers to capture emissions in bulk when producing hydrogen, instead of trying to capture, collect, transport, and store emissions from millions of points of natural gas end use – which is much costlier to do. But gas producers (both companies and countries) facing increasing pressure to account for the emissions from the combustion of their products will need further favourable policies for hydrogen if this is to be the solution. In some regions, these policies are already coming into place.

FIGURE 3.7

Hydrogen demand by region

Units: EJ/yr



Only includes hydrogen used as energy carrier.

3.5.2 HYDROGEN TO SCALE FROM 2040, LED BY EUROPE AND GREATER CHINA

In 2050, we forecast that hydrogen will supply 23% of end-use demand for gaseous fuels. This includes consumption of hydrogen and natural gas, but not use for production of electricity and other carriers. Hydrogen will account for almost half of end-use gas demand in Europe in 2050, 43% in Greater China, 37% in OECD Pacific, and a fifth of such demand in North America. These regions will see far and away the greatest reductions in emissions to 2050, and will account for most emissions abated by CCS.

It is difficult to use electrical substitutes in hard-to-abate sectors such as steelmaking and other heat-intensive industrial processes, jet-powered aircraft, and the ships, trains, and trucks that rely on the high torque of diesel engines.

In the future, some of these applications will be powered by natural gas, which is cleaner burning than other fossil fuels but is still a major source of emissions. This is where hydrogen can play a key role.

We see this in our forecast. From almost no demand today, demand for hydrogen as an energy carrier (for energy end use – not hydrogen used as a chemical feedstock) emerges in the late 2020s to begin scaling in the mid-2030s due to demand from the transport sector, mostly from larger vehicles. Moderate demand from buildings adds to this, and is then buoyed significantly by demand from manufacturing in the 2040s, with transport demand continuing to increase throughout. Together, Greater China (40%) and Europe (22%) will account for 62% of hydrogen demand in 2050 (Figure 3.7).

EU HYDROGEN STRATEGY VS OUR ETO

The ambition of the EU hydrogen strategy goes significantly beyond the outlook we forecast based on our ETO model, with EU targets 10 times our ETO projection. The EU strategy focuses on green hydrogen and targets 120 petajoules per year (PJ/yr) green hydrogen production in Europe in 2024 and 1,200 PJ/yr green hydrogen in 2030. We forecast just 12 PJ/yr green hydrogen production in Europe in 2024 and around 90 PJ/yr in 2030. In our ETO forecast, the EU 2030 target is in not reached until the early 2040s

Hydrogen demand in Greater China trails behind Europe to 2045, but then grows rapidly to nearly double the level of European demand in 2050. The earlier deployment in Europe is driven by policy and the higher carbon price which allows a business case for blue hydrogen. This, in turn, leads to cost reductions in CCS, which then becomes profitable at the forecasted carbon price in China, which is lower than projected for Europe.

3.5.3 CCS INTEGRAL TO SCALING HYDROGEN

Hydrogen can be produced in several ways, but if it is to help in the battle with climate change, the process will need to be produced with low greenhouse gas emissions.

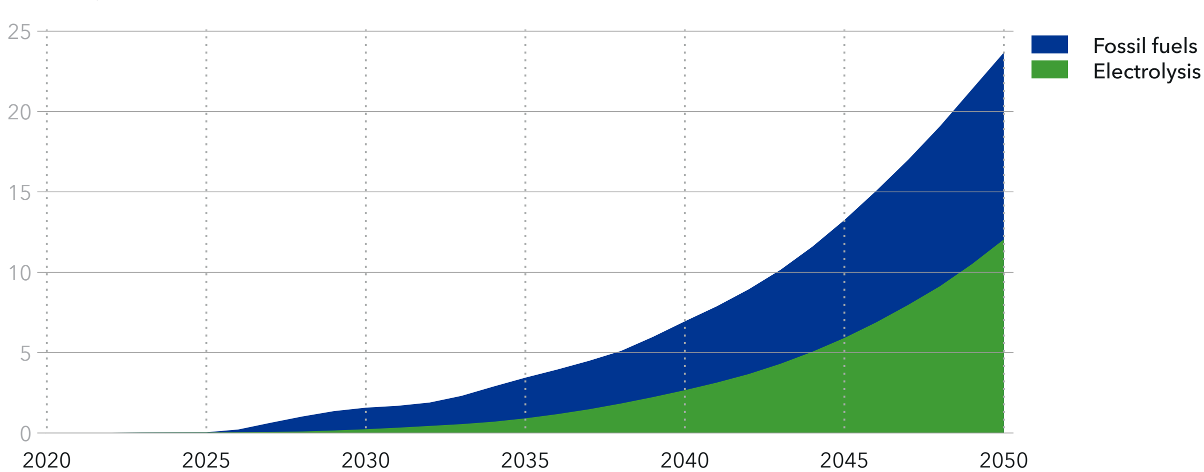
The cost of electrolysers and renewable energy is expected to fall over the next decade, making green hydrogen more viable (see "Producing hydrogen" on page 61). On the other hand, blue hydrogen has lower production costs and may have an equally low carbon footprint as green hydrogen, when lifecycle emissions of solar panels, wind farms, and natural gas production are taken into account. Synergies with the operation of infrastructure for natural gas – to distribute hydrogen by pipelines in pure or blended form – makes blue hydrogen a particularly appealing starting point for scaling the hydrogen economy. While green hydrogen production is commonly regarded as the ultimate destination, we forecast that the production of blue hydrogen will be key to scaling the hydrogen economy: 85% of hydrogen used as an energy carrier in 2030 will be blue hydrogen, according to our forecast.

We see a symbiotic roll-out of hydrogen deployment and uptake of CCS, as blue hydrogen production accounts for a significant share of CCS deployment and a dominant share of the demand for hydrogen as an energy carrier. Green hydrogen will ramp up from 2035 and grow at a faster pace than blue hydrogen in the 2040s (Figure 3.8). Production of blue hydrogen will, however, continue to grow throughout the forecast period, as use of hydrogen as an energy carrier, and CCS deployment, both exhibit similar growth trajectories with exponential growth from 2040 onwards. By mid-century, production levels of blue and green hydrogen will be roughly equal. The production split will differ by region, as strategies for hydrogen vary significantly based on national resources and priorities.

FIGURE 3.8

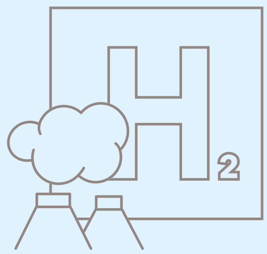
World hydrogen production by source

Units: EJ/yr



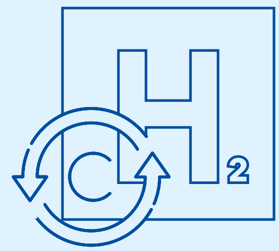
Only includes hydrogen used as energy carrier.

PRODUCING HYDROGEN



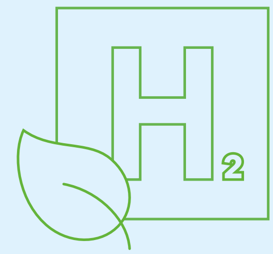
Grey & Brown Hydrogen

- Grey hydrogen is typically produced from natural gas in a process called steam methane reformation
- Brown hydrogen is produced from the gasification of coal (or lignite)
- These are by far the most dominant methods in use today
- They are relatively cheap, but emit large amounts of CO_2.



Blue Hydrogen

- Blue hydrogen is produced from fossil fuels (typically natural gas, but also coal), but emissions are dealt with using CCS technology
- With abundant natural gas and coal available, blue hydrogen could help to scale the hydrogen economy*
- However, this is dependent on wider adoption of CCS
- Blue hydrogen could act as a stepping stone from grey/ brown to green hydrogen.



Green Hydrogen

- Green hydrogen is produced by the electrolysis of water
- The process is powered by zero-carbon electricity (e.g. wind and solar power)
- It is clean, but is currently too expensive**
- The cost of electrolyzers and renewable energy is expected to fall over the next decade, making green hydrogen more viable
- Green hydrogen is the ideal long-term, low-carbon way to produce hydrogen.

*Green hydrogen 'cheaper than unabated fossil-fuel H2 by 2030': Hydrogen Council, *Recharge*.
**'Path to hydrogen competitiveness: A cost perspective', Hydrogen Council.

3.5.4 SHIFTING THE TIMELINE ON HYDROGEN

Just as CCS is extremely sensitive to the carbon price, the scale of the hydrogen economy is sensitive to the level at which CCS scales, and this will be key to scaling hydrogen. Exploiting synergies with natural gas will also be key to turning ambition for the hydrogen economy into reality, as will supportive policies such as national hydrogen strategies. In the shorter term, the oil and gas industry can help to scale the hydrogen economy by proving the safety case for hydrogen, and by developing and adapting infrastructure for hydrogen.

Safety: For hydrogen to gain broad acceptance and adoption – in domestic settings and for new applications beyond current industrial uses – industry and regulators will need to establish robust safety standards for each specific use case, just as they do for other potentially dangerous substances. Work has already started. For example, gas network operators are collaborating to create guidelines for the introduction of hydrogen into natural gas networks.

Work is also underway, for example, to establish safety standards for hydrogen within homes, determine minimum purity levels, and explore small-scale, inner-city green hydrogen production. This represents impressive progress towards wider adoption of hydrogen, but more is needed to give governments, industry, and the public confidence in its safety.

Infrastructure: Whatever the application, the cost and technical challenges of hydrogen infrastructure will be significant. Even where existing infrastructure can be reused or repurposed, there will still be issues to resolve. For example: hydrogen may need to be operated at different pressures (or velocity) than natural gas / biogas; further research may be needed into whether hydrogen could have an adverse effect on materials (e.g. in pipes and valves); various appliances would need to be converted or replaced (e.g. water heaters, compressors, pumps and sensors). According to the Hydrogen Council, some USD 280 billion in global investment will be needed between now and 2030 to fully realize hydrogen's role in the energy transition: roughly 40% would go into production; around 30% into storage, transport, and distribution; 25% into product development and manufacturing capacity; and the remainder into new business models.

3.6 CCS TIMELINE TOO SLOW TO SUPPORT TARGETS UNDER PARIS AGREEMENT

3.6.1 CCS NOT SET TO SCALE UNTIL THE 2040s

CCS has the potential to decarbonize natural gas and reduce emissions from industry. However, it will not begin to scale until the 2030s, and not to a significant level until the 2040s, according to our forecast.

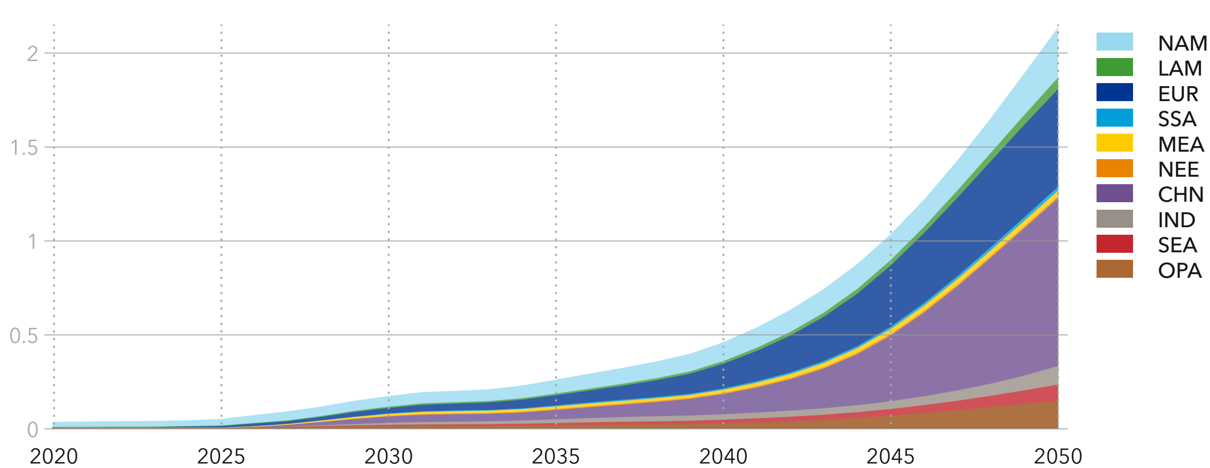
Around 40 million metric tonnes of anthropogenic CO_2 is currently captured and stored in geological formations each year. Our model forecasts that around 175 $MtCO_2$/yr will be injected and stored in 2030, some 450 $MtCO_2$/yr in 2040, and almost 2,200 $MtCO_2$/yr in 2050. While these forecasts indicate that CCS will scale, they also show, when taken with further research, that it will not scale early enough to help countries and the world to meet the targets set by the Paris Agreement.

On the positive side, our previous forecast (from 2019) predicted just over 800 $MtCO_2$/yr CCS capacity in 2050, meaning policy and technology developments in the past year have led us to predict an almost threefold increase in our 2020 forecast for CCS capacity by mid-century. On the negative side, the timeline has not changed.

FIGURE 3.9

World CCS capacity by region

Units: $GtCO_2$/yr



3.6.2 CCS ESSENTIAL TO MEET PARIS AGREEMENT

While we present one ETO forecast as the most likely outlook, we do in some cases undertake sensitivity studies on certain factors. In one such recent case, DNV GL prepared a study for Eurogas assessing how to achieve the European Commission's net-zero target in Europe, constraining our model with this as the end goal.[31] Based on this, we developed scenarios for two pathways to net zero. The first was based more on the strengths of the European gas sector and the advantages of energy delivery through existing gas networks, while the second focused on replacing gaseous energy with (primarily) electricity.

In both scenarios, all sectors needed extensive deployment of CCS of around 1 $GtCO_2$/yr (slightly less for the electrification scenario), and crucially Europe would need to reach this level of CCS deployment by 2035, meaning it needs to scale now, not in the 2040s as our model forecasts.

Extrapolating these findings to the global energy transition, CCS will be essential for the world meeting the targets set by the Paris Agreement. This is recognized by many within the oil and gas industry. Some 55% of the 1,000 senior oil and gas professionals we surveyed in late 2019 agreed that the industry will not be able to decarbonize without greater uptake of CCS[9].

CCS is a key technology to reduce emissions along the oil and gas value chain, from gas processing and refining, to end use of gas products for power generation or heat. But CCS is also an instrumental technology to lower emissions from other industries that otherwise are not easily abated. This applies for instance to CO_2 emissions from cement production, where typically some two thirds of the emissions stem from calcination of limestone. By storing CO_2 that does not stem from their own operations, oil and gas companies may potentially deduct a proportionate share of emissions on their carbon accounting balance sheets, claiming offsets in their inventory of GHG emissions.

3.6.3 EUROPE, CHINA, AND THE EFFECT OF CARBON PRICING

In 2050, we forecast that China and Europe combined will account for 66% of the world's CCS deployment (Figure 3.9). Carbon price will play a significant part in this, with wide-scale deployment of CCS requiring that a price be set on carbon that matches or exceeds the cost of deploying the technology. If CCS becomes commercially viable because of a carbon price, we then expect the cost of the technology to fall as it begins to scale. The key to this though, is that someone needs to go first.

In our forecasts, this will be Europe, with net-zero targets driving the implementation of a higher carbon price (Figure 3.4). With falling cost of the technology, and with rises in the carbon price also in other regions, CCS eventually begins to scale. In Greater China, we forecast CCS to scale significantly as these factors align post 2045, and for implementation to begin to scale in North America.

3.6.4 CCS UPTAKE DRIVEN BY HYDROGEN

Just as CCS uptake is essential to realizing the hydrogen economy, hydrogen will in turn drive the uptake of CCS. The use of hydrogen as an energy carrier is principally driven by the need to decarbonize, meaning all production from natural gas, coal or oil must be equipped with CCS.

Around 42% of CCS deployment in 2050 will be associated with production of blue hydrogen used as an energy carrier (Figure 3.10), which is projected to account for 49% of the global demand for hydrogen as an energy carrier. Production of hydrogen currently used by industry, mostly as a feedstock, emits some 830 $MtCO_2$/yr according to the IEA. More than 99% of pure hydrogen is currently produced from natural gas, coal, or oil. Less than 0.4% of this production is equipped with CCS. In the future, a significant fraction of this hydrogen production, not being used as an energy carrier, will also need to be decarbonized through use of green or blue hydrogen.

Hydrogen used as a feedstock in industry is not reflected in the hydrogen projections in the ETO model. However, the "Non gas reforming CCS capacity" projections include CCS applied to production of hydrogen used as feedstock, e.g. for ammonia or methanol production, or in refinery operations. Hydrogen production therefore accounts for a greater share of CCS deployment than is shown in Figure 3.10.

3.6.5 WILL THE OIL AND GAS INDUSTRY BECOME THE WORLD'S CARBON WASTE DISPOSAL AGENT?

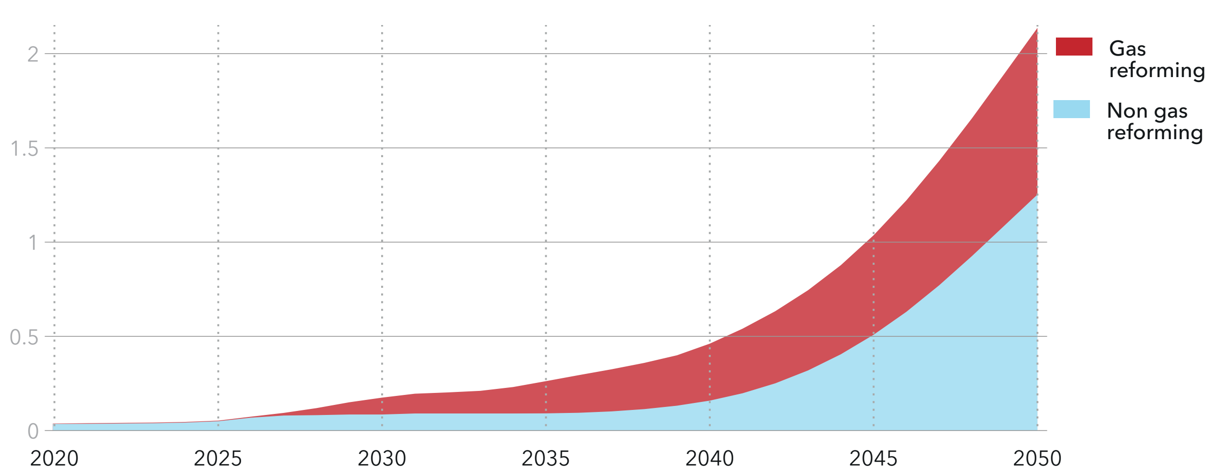
While the oil and gas industry has historically had a high carbon footprint (from production, processing, and combustion), it also has a major role in enabling other industries become carbon neutral – oil and gas industry technology and competence are required for CCS deployment.

Looking to the longer term, the oil and gas industry's raison d'être may slowly change from providing cheap and versatile fuels to meet global energy needs, to be the world's carbon waste disposal agent as CO_2 storage-site operators. Projects storing CO_2 emissions that do not stem from their own company operations can represent negative emissions in the storage company's GHG accounting. With time, the oil and gas industry – as we know it – may go carbon negative. This will require principles and methods for accounting and exchange of emissions reductions between companies participating in the value chain of CCS projects.

FIGURE 3.10

World CCS capacity

Units: $GtCO_2$/yr



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HISTORICAL DATA

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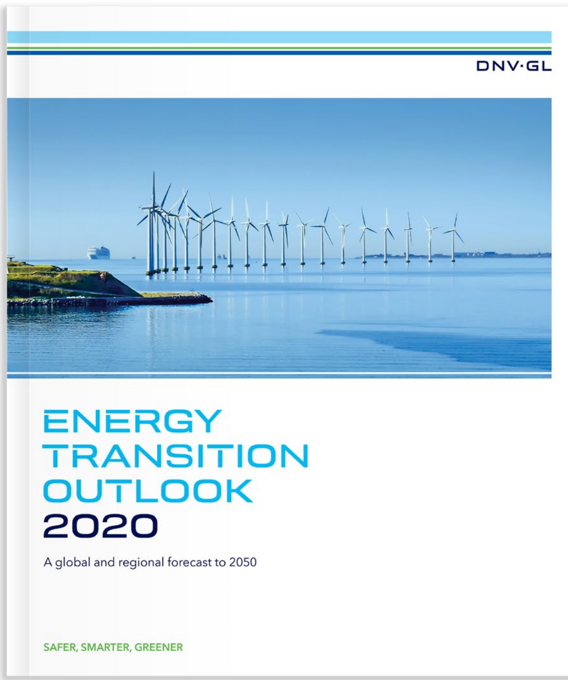
ENERGY TRANSITION OUTLOOK 2020 REPORTS OVERVIEW

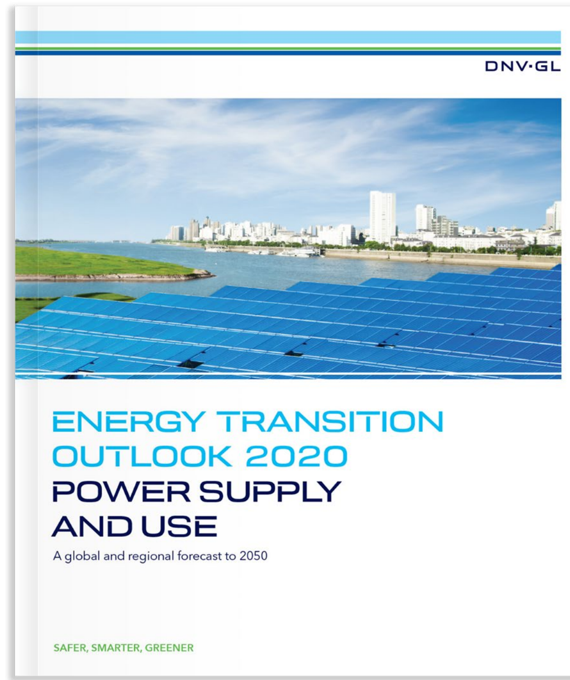


ENERGY TRANSITION OUTLOOK

Our main publication details our model-based forecast of the world's energy system through to 2050. It gives our independent view of what we consider the most likely trajectory of the coming energy transition, covering:

- The global energy demand for transport, buildings, and manufacturing,
- The changing energy supply mix, energy efficiency and expenditures
- Detailed energy outlooks for 10 world regions
- The climate implications of our forecast and solutions for closing the gap to well below 2°C

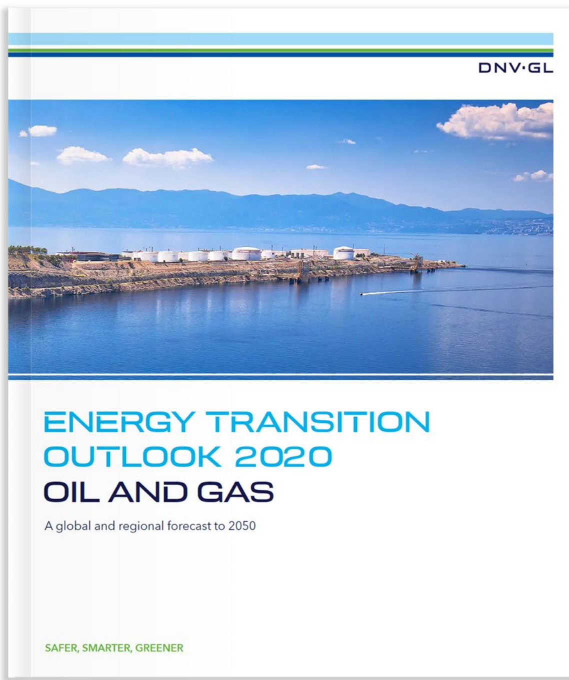
We also provide background details on the workings of our model and on our main assumptions (including population, GDP, technology costs and government policy). Our 2020 Outlook also details the impact of COVID-19 on the energy transition.



POWER SUPPLY AND USE

This report presents implications of our energy forecast to 2050 for key stakeholders involved in electricity generation, electricity transmission and distribution, and energy use. Amidst electricity use increasing rapidly and production becoming dominated by renewables, the report details important industry implications.
These include:

- Substantial opportunities for those parties involved in solar and wind generation
- Massive expansion, reinforcement and upgrading of transmission and distribution networks
- Further need for implementation of energy efficiency measures
- Acceleration of the electric vehicle revolution
- Digitalization enabling process improvements and smarter operations
- The energy transition is fast, but not fast enough to meet the goals of the Paris Agreement.



OIL AND GAS

This report provides the demand, supply, and investment forecast for hydrocarbons to 2050:

- The world is moving from more oil to cheapest oil as demand declines
- LNG is set to thrive in a strong gas market
- We forecast multiple energy transitions: from coal and oil to natural gas; and fossil fuels to renewables and decarbonized gas.

Further, we focus on decarbonizing the oil and gas industry:

- Pressure is mounting as emissions are set to remain stubbornly high until mid-2030s
- Decarbonization is on the agenda of industry and government, but not at the pace or depth to meet the Paris Agreement
- Hydrogen and CCS have the potential to transform the industry.

MARITIME

This year's Maritime Forecast aims to enhance the decision-making of shipowners as they navigate the technological, regulatory and market uncertainties surrounding decarbonization:

- A library of 30 scenarios has been developed that project future fleet composition, energy use, fuel mix, and CO_2 emissions to 2050. Each of our scenarios belongs to one of three distinct decarbonization pathways.
- We model 16 different fuel types and 10 fuel technology systems. We analyse how particular fuel technology alternatives perform commercially in a new Panamax bulk carrier as a case study.

Managing decarbonization risks is critical to protect the future value, profitability, and competitiveness of a vessel. Picking the wrong fuel solution today can lead to a significant competitive disadvantage.

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ABOUT DNV GL
We are the independent expert in risk management and quality assurance. Driven by our purpose, to safeguard life, property and the environment, we empower our customers and their stakeholders with facts and reliable insights so that critical decisions can be made with confidence. As a trusted voice for many of the world's most successful organizations, we use our knowledge to advance safety and performance, set industry benchmarks, and inspire and invent solutions to tackle global transformations.

As the technical advisor to the oil and gas industry, we bring a broader view to complex business and technology risks in global and local markets. Providing a neutral ground for industry cooperation, we create and share knowledge with our customers, setting standards for technology development and implementation. From project initiation to decommissioning, our independent experts enable companies to make the right choices for a safer, smarter and greener future.

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