World Energy Outlook 2017

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- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
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The first *World Energy Outlook (WEO)* appeared 40 years ago, in 1977. It has come a long way since then, and I have accompanied the *WEO* along much of this journey, first as an analyst in 1995, then later as Chief Economist. And, for the last three editions I have seen the *WEO* from a new vantage point as Executive Director.

These are extraordinary times for global energy, and they are reflected in what I believe is an extraordinary *WEO*. The analytical focus is on four major trends that are profoundly reshaping the energy sector and that I expect to continue to do so in the years ahead. These are the continued cost reductions for clean energy technologies, notably solar PV, wind (both on and offshore), as well as batteries; the rapidly increasing importance of electricity and digital technologies across the energy sector; the significant changes underway to reduce the energy intensity of China's economy and the carbon intensity of its energy – a topic of in-depth study in this *Outlook*; and the dynamism of the shale sector in the United States. All of these trends, but especially the last, are having a major impact on the outlook for natural gas, this year's fuel focus.

The attention to China is particularly timely, as this is one of the countries – alongside Brazil, India, Indonesia, Morocco, Singapore and Thailand – that have become Associate members of the International Energy Agency (IEA) over the last two years, part of the Agency's modernisation strategy to "open the doors" to the key energy players around the world. I take this opportunity to thank the numerous experts from China that have contributed so much to this analysis.

The aim of the *WEO* has remained constant throughout the years, and there is a phrase in this year's publication that captures it well: success for the *WEO* is about helping countries to achieve the long-term energy goals that they have chosen.

To this end, decision-makers need two points of orientation. First, they need to know the direction in which they are heading: that is the purpose of the New Policies Scenario, derived from the policies already in place and those officially announced (with the Current Policies Scenario providing information about the outlook on the basis of just those policies already in place).

Second, decision-makers also need to know where they would *like* to get to. For an answer to this question, we look to the goals that have been agreed internationally. This year's *Outlook* introduces, for the first time, the Sustainable Development Scenario. This reflects the energy-related objectives that the international community has set with the United Nations 2030 Agenda for Sustainable Development: an appropriate answer to our climate change challenge, while improving air quality and achieving universal access to modern energy services – in short, secure, affordable, sustainable energy that is available to all.

The IEA does not have a long-term forecast and, in my view, does not need one, however reasonable, to inform deliberations about the future. It needs a strong evidence base, with a transparent methodology, to provide a framework for today's decisions.

I would like to applaud the dedication and skill of the team, led by Laura Cozzi and Tim Gould, that has developed the 2017 edition, and to all the friends and colleagues from around the world that have provided time and expertise in support of the new *Outlook*.

Dr. Fatih Birol
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1. *Southeast Asia Energy Outlook 2017* was launched in Singapore on 24 October 2017. It is available to download at: *www.iea.org/southeastasia*.

2. *Energy Access Outlook: from Poverty to Prosperity* was launched in Rome, Italy on 19 October 2017. It is available to download at: *www.iea.org/energyaccess.*

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- Roundtable Meeting on China's Energy Outlook, Beijing, 16 February 2017.

- 5th IEA Unconventional Gas Forum, organised with the Centre for Coal Seam Gas and the Energy Initiative at The University of Queensland, Brisbane, 24 February 2017.
- High-level Workshop on Energy and Development, Paris, 27 March 2017.
- High-level Workshop on the Strategic Role of Natural Gas, organised with the Center for Strategic and International Studies, Washington, D.C., 5 May 2017.

Further details on these events are at: *www.iea.org/workshops* and *www.iea.org/ugforum*.

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Part C: China Energy Outlook

Four large-scale shifts in the global energy system set the scene for the *World Energy Outlook-2017 (WEO-2017)*:

- The **rapid deployment and falling costs of clean energy technologies**; in 2016, growth in solar PV capacity was larger than for any other form of generation; since 2010, costs of new solar PV have come down by 70%, wind by 25% and battery costs by 40%.
- The **growing electrification of energy**; in 2016, spending by the world's consumers on electricity approached parity with their spending on oil products.
- The **shift to a more services-oriented economy and a cleaner energy mix in China,** the world's largest energy consumer, subject of a detailed focus in this *Outlook*.
- The resilience of **shale gas and tight oil in the United States,** cementing its position as the biggest oil and gas producer in the world even at lower prices.

These shifts come at a time when traditional distinctions between energy producers and consumers are being blurred and a new group of major developing countries, led by India, moves towards centre stage. How these developments play out and interact is the story of this *Outlook*, with particular attention paid to their implications for natural gas, this year's fuel focus. Together, they are opening up new perspectives for affordable, sustainable access to modern energy, reshaping responses to the world's pressing environmental challenges, and entailing a reappraisal and reinforcement of approaches to energy security.

Our new *Outlook* describes multiple future pathways for global energy through to 2040. Among them, the **New Policies Scenario** describes where existing policies and announced intentions might lead the energy system, in the anticipation that this will inform decision-makers as they seek to improve on this outcome. The **Sustainable Development Scenario**, a major new scenario introduced in the *WEO-2017*, outlines an integrated approach to achieve the energy-related aspects of the UN Sustainable Development Goals: determined action on climate change; universal access to modern energy by 2030; and a dramatic reduction in air pollution. These are all areas in which progress in the New Policies Scenario falls short of what would be required.

Add an extra China-plus-India to global energy demand by 2040

In the New Policies Scenario, global energy needs rise more slowly than in the past but still expand by 30% between today and 2040, the equivalent of adding another China and India to today's global demand. A global economy growing at an average rate of 3.4% per year, a population that expands from 7.4 billion today to more than 9 billion in 2040, and a process of urbanisation that adds a city the size of Shanghai to the world's urban population every four months are key forces that underpin our projections. The largest contribution to demand growth – almost 30% – comes from India, whose share of global energy use rises to 11% by 2040 (still well below its 18% share in the anticipated global population). Southeast Asia, a region covered in a separate special report in the *WEO-2017* series, is another rising heavyweight in global energy, with demand growing at twice the pace of China. Overall, developing countries in Asia account for two-thirds of global energy growth, with the rest coming mainly from the Middle East, Africa and Latin America.

Renewables step up to the plate; coal strikes out

Compared with the past twenty-five years, the way that the world meets its growing energy needs changes dramatically in the New Policies Scenario, with the lead now taken by natural gas, by the rapid rise of renewables and by energy efficiency. Improvements in efficiency play a huge role in taking the strain off the supply side: without them, the projected rise in final energy use would more than double. Renewable sources of energy meet 40% of the increase in primary demand and their explosive growth in the power sector marks the end of the boom years for coal. Since 2000, coal-fired power generation capacity has grown by nearly 900 gigawatts (GW), but net additions from today to 2040 are only 400 GW and many of these are plants already under construction. In India, the share of coal in the power mix drops from three-quarters in 2016 to less than half in 2040. In the absence of large-scale carbon capture and storage, global coal consumption flatlines. Oil demand continues to grow to 2040, albeit at a steadily decreasing pace. Natural gas use rises by 45% to 2040; with more limited room to expand in the power sector, industrial demand becomes the largest area for growth. The outlook for nuclear power has dimmed since last year's *Outlook*, but China continues to lead a gradual rise in output, overtaking the United States by 2030 to become the largest producer of nuclear-based electricity.

Renewables capture two-thirds of global investment in power plants as they become, for many countries, the least-cost source of new generation. Rapid deployment of solar photovoltaics (PV), led by China and India, helps solar become the largest source of low-carbon capacity by 2040, by which time the share of all renewables in total power generation reaches 40%. In the European Union, renewables account for 80% of new capacity and wind power becomes the leading source of electricity soon after 2030, due to strong growth both onshore and offshore. Policies continue to support renewable electricity worldwide, increasingly through competitive auctions rather than feed-in tariffs, and the transformation of the power sector is amplified by millions of households, communities and businesses investing directly in distributed solar PV. Growth in renewables is not confined to the power sector; the direct use of renewables to provide heat and mobility worldwide also doubles, albeit from a low base. In Brazil, the share of direct and indirect renewable use in final energy consumption rises from 39% today to 45% in 2040, compared with a global progression from 9% to 16% over the same period.

The future is electrifying

Electricity is the rising force among worldwide end-uses of energy, making up 40% of the rise in final consumption to 2040 – the same share of growth that oil took for the last twenty-five years. Industrial electric motor systems account for one-third of the increase in power demand in the New Policies Scenario. Rising incomes mean that many millions of households add electrical appliances (with an increasing share of "smart" connected devices) and install cooling systems. By 2040, electricity demand for cooling in China exceeds the total electricity demand of Japan today. The world also gains, on average, 45 million new electricity consumers each year due to expanding access to electricity, although this is still not enough to reach the goal of universal access by 2030. Electricity makes inroads in supplying heat and mobility, alongside growth in its traditional domains, allowing its share of final consumption to rise to nearly a quarter. A strengthening tide of industry initiatives and policy support – including recent decisions by governments in France and the United Kingdom to phase out sales of conventional gasoline and diesel vehicles by 2040 – pushes our projection for the global electric car fleet up to 280 million by 2040, from 2 million today.

To meet rising demand, China needs to add the equivalent of today's United States power system to its electricity infrastructure by 2040, and India needs to add a power system the size of today's European Union. The scale of future electricity needs and the challenge of decarbonising power supply help to explain why global investment in electricity overtook that of oil and gas for the first time in 2016 and why electricity security is moving firmly up the policy agenda. Cost reductions for renewables are not sufficient on their own to secure efficient decarbonisation or reliable supply. The policy challenge is to ensure sufficient investment in electricity networks and in a mix of generation technologies that are the best fit for power system needs, providing the flexibility that is increasingly vital as the contribution of wind and solar PV increases (a consideration that reinforces the links between electricity and gas security). The increasing use of digital technologies across the economy improves efficiency and facilitates the flexible operation of power systems, but also creates potential new vulnerabilities that need to be addressed.

When China changes, everything changes

China is entering a new phase in its development, with the emphasis in energy policy now firmly on electricity, natural gas and cleaner, high-efficiency and digital technologies. The previous orientation towards heavy industry, infrastructure development and the export of manufactured goods lifted hundreds of millions out of poverty – including energy poverty – but left the country with an energy system dominated by coal and a legacy of serious environmental problems, giving rise to almost 2 million premature deaths each year from poor air quality. The president's call for an "energy revolution", the "fight against pollution" and the transition towards a more services-based economic model is moving the energy sector in a new direction. Demand growth slowed markedly from an average of 8% per year from 2000 to 2012 to less than 2% per year since 2012, and in the New Policies Scenario it slows further to an average of 1% per year to 2040. Energy efficiency regulation explains a large part of this slowdown, without new efficiency measures, end-use consumption in 2040 would be 40% higher. Nonetheless, by 2040 per-capita energy consumption in China exceeds that of the European Union.

China's choices will play a huge role in determining global trends, and could spark a faster clean energy transition. The scale of China's clean energy deployment, technology exports and outward investment makes it a key determinant of momentum behind the low-carbon transition: one-third of the world's new wind power and solar PV is installed in China in the New Policies Scenario, and China also accounts for more than 40% of global investment in electric vehicles (EVs). China provides a quarter of the projected rise in global gas demand and its projected imports of 280 billion cubic metres (bcm) in 2040 are second only to those of the European Union, making China a lynchpin of global gas trade. China overtakes the United States as the largest oil consumer around 2030, and its net imports reach 13 million barrels per day (mb/d) in 2040. But stringent fuel-efficiency measures for cars and trucks, and a shift which sees one-in-four cars being electric by 2040, means that China is no longer the main driving force behind global oil use – demand growth is larger in India post-2025. China remains a towering presence in coal markets, but our projections suggest that coal use peaked in 2013 and is set to decline by almost 15% over the period to 2040.

The shale revolution in the United States is turning to exports

A remarkable ability to unlock new resources cost-effectively pushes combined United States oil and gas output to a level 50% higher than any other country has ever managed; already a net exporter of gas, the US becomes a net exporter of oil in the late 2020s. In our projections, the 8 mb/d rise in US tight oil output from 2010 to 2025 would match the highest sustained period of oil output growth by a single country in the history of oil markets. A 630 bcm increase in US shale gas production over the 15 years from 2008 would comfortably exceed the previous record for gas. Expansion on this scale is having wide-ranging impacts within North America, fuelling major investments in petrochemicals and other energy-intensive industries. It is also reordering international trade flows and challenging incumbent suppliers and business models. By the mid-2020s, the United States become the world's largest liquefied natural gas (LNG) exporter and a few years later a net exporter of oil – still a major importer of heavier crudes that suit the configuration of its refineries, but a larger exporter of light crude and refined products. This reversal is by no means only a supply-side story; without continued improvements in fuel-economy standards, the United States would remain a net oil importer. In our projections, factoring in extra volumes from Canada and Mexico, North America emerges as the largest source of additional crude oil to the international market (growth in refinery capacity and demand in the Middle East limits the supply of extra crude from this region). By 2040, around 70% of the world's oil trade ends up in a port in Asia, as the region's crude oil imports expand by a massive 9 mb/d. The shifting pattern of risks implies a significant reappraisal of oil security and how best to achieve it.

EVs are coming fast, but it is still too early to write the obituary for oil

With the United States accounting for 80% of the increase in global oil supply to 2025 and maintaining near-term downward pressure on prices, the world's consumers are not yet ready to say goodbye to the era of oil. Up until the mid-2020s demand growth remains robust in the New Policies Scenario, but slows markedly thereafter as greater efficiency and fuel switching bring down oil use for passenger vehicles (even though the global car fleet doubles from today to reach 2 billion by 2040). Powerful impetus from other sectors is enough to keep oil demand on a rising trajectory to 105 mb/d by 2040: oil use to produce petrochemicals is the largest source of growth, closely followed by rising consumption for trucks (fuel-efficiency policies cover 80% of global car sales today, but only 50% of global truck sales), for aviation and for shipping. Once US tight oil plateaus in the late 2020s and non-OPEC production as a whole falls back, the market becomes increasingly reliant on the Middle East to balance the market. There is a continued large-scale need for investment to develop a total of 670 billion barrels of new resources to 2040, mostly to make up for declines at existing fields rather than to meet the increase in demand. This puts steady upward pressure on costs and prices in the New Policies Scenario, as supply and services markets tighten and companies have to move on to more complex new projects.

Even greater upside for US tight oil and a more rapid switch to electric cars would keep oil prices lower for longer. We explore this possibility in a Low Oil Price Case, in which a doubling of the estimate for tight oil resources, to more than 200 billion barrels, boosts US supply and more widespread application of digital technologies helps to keep a lid on upstream costs around the globe. Extra policy and infrastructure support pushes a much more rapid expansion in the global electric car fleet, which approaches 900 million cars by 2040. Along with a favourable assumption about the ability of the main oil-producing regions to weather the storm of lower hydrocarbon revenues, this is enough to keep prices within a $50-70/barrel range to 2040. However, it is not sufficient to trigger a major turnaround in global oil use. Even with a rapid transformation of the passenger car fleet, reaching a peak in global demand would require stronger policy action in other sectors. Otherwise, in a lower oil price world, consumers have few economic incentives to make the switch away from oil or to use it more efficiently. Meanwhile, with projected demand growth appearing robust, at least for the near term, a third straight year in 2017 of low investment in new conventional projects remains a worrying indicator for the future market balance, creating a substantial risk of a shortfall of new supply in the 2020s.

LNG ushers in a new order for global gas markets

Natural gas, the fuel focus in *WEO-2017*, grows to account for a quarter of global energy demand in the New Policies Scenario by 2040, becoming the second-largest fuel in the global mix after oil. In resource-rich regions, such as the Middle East, the case for expanding gas use is relatively straightforward, especially when it can substitute for oil. In the United States, plentiful supplies maintain a strong share of gas-fired power in electricity generation through to 2040, even without national policies limiting the use of coal. But 80% of the projected growth in gas demand takes place in developing economies, led by China, India and other countries in Asia, where much of the gas needs to be imported (and so transportation costs are significant) and infrastructure is often not yet in place. This reflects the fact that gas looks a good fit for policy priorities in this region, generating heat, power and mobility with fewer carbon-dioxide (CO_2) and pollutant emissions than other fossil fuels, helping to address widespread concerns over air quality. But the competitive landscape is formidable, not just due to coal but also to renewables, which in some countries become a cheaper form of new power generation than gas by the mid-2020s, pushing gas-fired plants towards a balancing rather than a baseload role. Efficiency policies also play a part in constraining gas use: while the electricity generated from gas grows by more than half to 2040, related gas use rises by only one-third, due to more reliance on highly efficient plants.

A new gas order is emerging, with US LNG helping to accelerate a shift towards a more flexible, liquid, global market. Ensuring that gas remains affordable and secure, beyond the current period of ample supply and lower prices, is critical for its long-term prospects. LNG accounts for almost 90% of the projected growth in long-distance gas trade to 2040: with few exceptions, most notably the route that opens up between Russia and China, major new pipelines struggle in a world that prizes the optionality of LNG. The transformation in gas markets is advanced by market liberalisation in Japan and other Asian economies and by the rise of portfolio players – large companies with a range of supply assets. New buyers, often smaller scale, are appearing: the number of LNG-importing countries has risen from 15 in 2005 to 40 today. Gas supply also becomes more diverse: the amount of liquefaction sites worldwide doubles to 2040, with the main additions coming from the United States and Australia, followed by Russia, Qatar, Mozambique and Canada. Price formation is based increasingly on competition between various sources of gas, rather than indexation to oil. With destination flexibility, hub-based pricing and spot availability, US LNG acts as a catalyst for many of the anticipated changes in the wider gas market. The new gas order can bring dividends for gas security, although there is the risk of a hard landing for gas markets in the 2020s if uncertainty over the pace or direction of change deters new investments. Over the longer term, a larger and more liquid LNG market can compensate for reduced flexibility elsewhere in the energy system (for example, lower fuel-switching capacity in some countries as coal-fired generation is retired). We estimate that, in 2040, it would take around ten days for major importing regions to raise their import levels by 10%, a week less than it might take today in Europe, Japan and Korea.

Access, air pollution and greenhouse-gas emissions: the world falls short

Universal access to electricity remains elusive, and scaling up access to clean cooking facilities is even more challenging. There are some positive signs: over 100 million people per year have gained access to electricity since 2012 compared with around 60 million per year from 2000 to 2012. Progress in India and Indonesia has been particularly impressive, and in sub-Saharan Africa electrification efforts outpaced population growth for the first time in 2014. But, despite this momentum, in the New Policies Scenario around 675 million people – 90% of them in sub-Saharan Africa – remain without access to electricity in 2030 (down from 1.1 billion today), and 2.3 billion continue to rely on biomass, coal or kerosene for cooking (from 2.8 billion today). Household air pollution from these sources is currently linked to 2.8 million premature deaths per year, and several billion hours are spent collecting firewood for cooking, mostly by women, that could be put to more productive uses.

Policy attention to air quality is rising and global emissions of all the major pollutants fall in our projections, but their health impacts remain severe. Ageing populations in many industrialised societies become more vulnerable to the effects of air pollution and urbanisation can also increase exposure to pollutants from traffic. Premature deaths worldwide from outdoor air pollution rise from 3 million today to more than 4 million in 2040 in the New Policies Scenario, even though pollution control technologies are applied more widely and other emissions are avoided because energy services are provided more efficiently or (as with wind and solar) without fuel combustion.

Despite their recent flattening, global energy-related CO_2 emissions increase slightly to 2040 in the New Policies Scenario. This outcome is far from enough to avoid severe impacts of climate change, but there are a few positive signs. Projected 2040 emissions in the New Policies Scenario are lower by 600 million tonnes than in last year's *Outlook* (35.7 gigatonnes [Gt] versus 36.3 Gt). In China, CO_2 emissions are projected to plateau at 9.2 Gt (only slightly above current levels) by 2030 before starting to fall back. Worldwide emissions from the power sector are limited to a 5% increase between now and 2040, even though electricity demand grows by 60% and global GDP by 125%. However, the speed of change in the power sector is not matched elsewhere: CO_2 emissions from oil use in transport almost catch up with those from coal-fired power plants (which are flat) by 2040, and there is also a 20% rise in emissions from industry.

An integrated approach can close the gap with the Sustainable Development Goals

The Sustainable Development Scenario offers an integrated way to achieve a range of energy-related goals crucial for sustainable economic development: climate stabilisation, cleaner air and universal access to modern energy, while also reducing energy security risks. This scenario starts from a set of desired outcomes and considers what would be necessary to deliver them. Central to these outcomes is the achievement of an early peak in CO_2 emissions and a subsequent rapid decline, consistent with the Paris Agreement. A key finding is that universal access to electricity and clean cooking can be reached without making this task any more challenging. We also investigate, in a Faster Transition Scenario, how policies could push an even more rapid and steeper decline in CO_2 emissions and limit climate risks further.

In the Sustainable Development Scenario, low-carbon sources double their share in the energy mix to 40% in 2040, all avenues to improve efficiency are pursued, coal demand goes into an immediate decline and oil consumption peaks soon thereafter. Power generation is all but decarbonised, relying by 2040 on generation from renewables (over 60%), nuclear power (15%) as well as a contribution from carbon capture and storage (6%) – a technology that plays an equally significant role in cutting emissions from the industry sector. Electric cars move into the mainstream quickly, but decarbonising the transport sector also requires much more stringent efficiency measures across the board, notably for road freight. The 2030 targets for renewables and efficiency that are defined in the Sustainable Development agenda are met or exceeded in this scenario; renewables and efficiency are the key mechanisms to drive forward the low-carbon transition and reduce pollutant emissions. Considering the inter-linkages between them and aligning policy and market frameworks – notably in the residential sector – is essential to ensure cost-efficient outcomes. The provision of highly efficient appliances, combined with decentralised renewables, also play a major role in extending full access to electricity and clean cooking, especially in rural communities and isolated settlements that are hard to reach with the grid.

Natural gas can help clean energy transitions, but has homework to do

As oil and coal fall back and renewables ramp up strongly, natural gas becomes the largest single fuel in the global mix in the Sustainable Development Scenario. Securing clear climate benefits from gas use depends on credible action to minimise leaks of methane – a potent greenhouse gas – to the atmosphere. Consumption of natural gas rises by nearly 20% to 2030 in the Sustainable Development Scenario and remains broadly at this level to 2040. The contribution of gas varies widely across regions, between sectors and over time in this scenario. In energy systems heavily reliant on coal (as in China and India), where renewable alternatives are less readily available (notably in some industrial sectors), or where seasonal flexibility is required to integrate high shares of variable renewables, gas plays an important role. Stepping up action to tackle methane leaks along the oil and gas value chain is essential to bolster the environmental case for gas: these emissions are not the only anthropogenic emissions of methane, but they are likely to be among the cheapest to abate. We present the first global analysis of the costs of abating the estimated 76 million tonnes of methane emitted worldwide each year in oil and gas operations, which suggest that 40-50% of these emissions can be mitigated at no net cost, because the value of the captured methane could cover the abatement measures. Implementing these measures in the New Policies Scenario would have the same impact on reducing the average global surface temperature rise in 2100 as shutting all existing coal-fired power plants in China.

Investment, guided by policy, can write a different story about the future

The large-scale shifts in global energy that characterise our *WEO-2017* projections also reshape the outlook for energy investment. Electricity accounts for nearly half of total energy supply investment in the New Policies Scenario and almost two-thirds in the Sustainable Development Scenario, up from an average of 40% in recent years. Clean energy technologies and energy efficiency likewise take an increasing share of the $60 trillion in cumulative investment in supply and end-uses in the New Policies Scenario, and the bulk of the $69 trillion in the Sustainable Development Scenario. Nonetheless, upstream oil and gas investment remains a major component of a secure energy system, even in the carbon-constrained world of the Sustainable Development Scenario. Getting pricing signals and policy frameworks right would include phasing out subsidies that promote wasteful consumption of fossil fuels (at an estimated $260 billion in 2016, these are almost double the subsidies currently going to renewables). Along with a proliferation of community, municipal and private sector initiatives, well-designed policy remains essential to pursue a brighter energy future.

PART A
GLOBAL ENERGY TRENDS

PREFACE

Part A of this *WEO* (Chapters 1-7) presents energy projections to 2040. It covers the prospects for all energy sources, regions and sectors and considers the implications for climate change, energy security and the economy. The main focus is on the New Policies Scenario, but other possible pathways are also presented: the Current Policies Scenario, the Sustainable Development Scenario, the Faster Transition Scenario and a Low Oil Price Case.

Chapter 1 defines the scenarios and details the policy, technology, macroeconomic and demographic assumptions utilised in the analysis.

Chapter 2 provides an overview of key findings in the form of ten questions and answers about the future of energy, asking what impact different policy, technology and investment choices might have on future energy trends and risks.

Chapter 3 reviews energy access, local pollution and greenhouse-gas emissions trends and presents an integrated approach to achieving international goals in these areas in the Sustainable Development Scenario, and discusses also a Faster Transition Scenario.

Chapter 4 focuses on the outlook for oil. On the demand side, the key elements are the impact of electric vehicles on oil demand, as well as the outlook for oil use for trucks and for petrochemicals. The chapter also has a detailed look at US tight oil, upstream costs, deepwater prospects and the dramatic reorientation that is underway in global crude oil and product trade flows.

Chapter 5 provides an outlook for coal, detailing the strong regional variations in projected demand for steam and coking coal, and the implications for production and trade.

Chapter 6 analyses the outlook for the power sector and highlights the emerging shift towards low-carbon technologies and natural gas. The chapter also examines the impact of electrification, the changing shape of electricity demand in developing countries and the relationship between technology costs and prices.

Chapter 7 combines the outlooks for both renewables (the subject of a detailed focus in last year's *Outlook*) and energy efficiency, while assessing the interlinkages between these two critically important policy areas.

Introduction and scope

Thinking about the future of energy

Highlights

- This year marks the 40th anniversary since the publication of the first *World Energy Outlook.* The breadth and depth of the *WEO* analysis has been transformed since then, but its ambition remains the same: to provide all those with a stake in the energy sector with a robust analysis of possible future energy pathways, under different sets of assumptions, as an aid to their decision-making.
- Two of the scenarios in the *WEO-2017* are retained from previous *Outlooks*. The Current Policies Scenario considers only those policies firmly enacted as of mid-2017; this default setting for the energy system is a benchmark against which the impact of "new" policies can be measured. The New Policies Scenario, our central scenario, incorporates existing energy policies as well as an assessment of the results likely to stem from the implementation of announced policy intentions. Among such announcements over the last year: the change in policy orientation in the United States; a wealth of additional detail on China's plans for an "energy revolution"; a stronger commitment to renewables and electric mobility in India; and plans to shift the power mix in Korea in favour of gas and renewables.
- Alongside these, the Sustainable Development Scenario appears for the first time, setting out a pathway to achieve the key energy-related components of the United Nations Sustainable Development agenda: universal access to modern energy by 2030; urgent action to tackle climate change (in line with the Paris Agreement); and measures to improve poor air quality.
- The principal determinants of energy demand growth are energy policies, which differ between scenarios, and the rates at which economic activity and population grow, which do not. In the *WEO-2017*, global GDP is assumed to grow at a compound average rate of 3.4% per year, close to the level in last year's *Outlook*. The world population is assumed to rise from 7.4 billion in 2016 to 9.1 billion in 2040.
- The price of energy and the costs of key energy technologies evolve differently in the various scenarios, depending on levels of deployment and on supply-demand balances. A common thread however is that costs for key low-carbon technologies – notably solar, wind and batteries – continue to fall in the *Outlook* period, with major implications for investment trends. The outlook for nuclear has meanwhile dimmed somewhat, in response to signs of waning support in some countries.
- Prices for oil and natural gas both rise from today's levels, although the extent of this increase has been revised downwards since the *WEO-2016*. Downward pressure on prices is largely due to higher US production of tight oil and shale gas, for which costs have come down and resource estimates have increased.

1.1 The scenarios

This year's publication marks the 40th anniversary since the first *World Energy Outlook (WEO)* in 1977, and the 20th edition since it became a regular annual publication in 1998.[1] While the main purpose of this analysis – as usual – is to look forward at possible pathways for global energy, this is also a moment to look back at how the *Outlook* has evolved. The first *Outlook* in 1977 appeared in the aftermath of the first oil embargo in 1973-1974 and was unsurprisingly a product of its time. The focus was on oil (45% of the global energy mix at the time, versus 32% today) and on the countries of the Organisation for Economic Co-operation and Development (OECD) (71% of global oil demand at the time, 48% today): the emphasis of the analysis was on how much oil they might consume over the *Outlook* period (to 1985) and where they would get it from. Nonetheless, some essential parameters for the analysis were there from the start. The intention was not to predict the future, but to understand what difference policies could make to that future. There was a recognition of the centrality of energy security. And there were already alternative policy scenarios, looking at the impact of energy conservation measures (as they were called at the time) and the scope for alternative sources of oil supply within the OECD, in order to avoid some of the oil security risks projected in the reference case.

Fast-forward twenty years and the *WEO* had already taken on many of the features that are familiar today. For better or worse, it was bigger (weighing in at more than 450 pages versus the 100 or so pages in 1977) and based on a new *World Energy Model* (*WEM*) covering all regions and fuels – the distant forerunner of the model used today. A central concern was still the outlook for oil markets and oil market security, but gas security also featured strongly: "Our work on natural gas suggests no reserve limitations on production at world level before 2020, although increasing use of unconventional gas in North America is likely." (IEA, 1998). But the most noticeable new element was the attention given to the environmental impacts of energy use, with extensive analysis of energy-related carbon dioxide (CO_2) emissions and the implementation of the 1997 Kyoto Protocol: "New policies will be required if the use of nuclear power and renewable energy sources is to help reduce fossil-fuel consumption and greenhouse-gas emissions […] unit costs of renewable energy must be reduced." (IEA, 1998).

The underlying philosophy and intent of the *Outlook* is captured well in the preface to the 1998 edition. In the words of the (then) IEA Executive Director: "The objective of this book is not to state what the IEA believes will happen to the energy system in future. The IEA holds no such single view. Rather, the aim is to discuss the most important factors and uncertainties likely to affect the energy system over the period to 2020 […] In fact, the IEA expects that the future for world energy will be quite different from that described in the business-as-usual (BAU) projection. This is partly because economic growth, energy prices,

1. The *WEO* was published in 1977, 1982 and from 1993 to 1996, and then again annually from 1998 onwards. All the *WEOs* since 1994 are available to download from *www.iea.org/weo/previousworldenergyoutlooks*.

technology and consumer behaviour will turn out to be different from those assumed for the BAU projection. The most striking difference will most likely occur because governments in developed countries will want to change things." Although we now think in terms of all governments, not just those in developed countries, it is this ability to change things on the part of governments (and others, including energy companies) that is at the heart of the *WEO* process. The intention is to inform decision-makers as they consider their options, not to predict the outcomes of their deliberations.

Box 1.1 ▷ How has the *World Energy Outlook* evolved since 1977?

Although the underlying purpose of the work has remained remarkably constant, much has changed in the *Outlook* since it made its first appearance 40 years ago. Up until 2010, the structure tended to focus on a Reference Scenario, in which policy assumptions were fixed at the present day, with no account taken of announced intentions or targets. This was often accompanied by an alternative scenario to examine the impact of different policy choices to address a specific energy security or environmental issue.

In 2010, the main focus shifted to the New Policies Scenario (and the old Reference Scenario moved to the background, becoming the Current Policies Scenario). The 450 Scenario made its initial appearance as a pathway to limit climate change to below 2 degrees Celsius (°C), cementing the position of climate and other environmental issues at the heart of the analysis (and becoming a global benchmark for climate trajectories). Since then, scenarios have addressed a range of other uncertainties over prices and the deployment of specific technologies.

The geographical reach of the analysis has expanded considerably. From an early focus on the OECD member countries, the *WEO* has broadened its horizons to provide a truly global outlook. Since 2005, this has involved an annual in-depth country or regional focus, starting that year with the Middle East and North Africa, and since then including China and India (2007), Russia (2011), Iraq (2012), Brazil (2013), sub-Saharan Africa (2014), India (2015) and Mexico (2016). Underlining the importance of Asia to the future of global energy, this year the geographic focus again turns to China, ten years on from the 2007 analysis.

The thematic reach of the analysis has also grown. The annual "fuel focus" was added in 2008 and has since covered all the major fuels and technologies, including energy efficiency. Access to modern energy has become a signature issue, with systematic monitoring of the numbers of the global population without basic energy services, together with analysis of the policies, technologies and investment required to close this gap. The *Outlook* has likewise taken a lead in highlighting and quantifying fossil-fuel consumption subsidies, and the links between energy and international competitiveness, air pollution and water use.

In addition, the *WEO* has evolved to include the regular appearance of special reports alongside the main *Outlook*. The first of these, in 2011, asked the question "Are we entering a Golden Age of Gas?". The *WEO-2017* series, in addition to this *Outlook*, includes two special reports: a regional energy outlook for Southeast Asia and an in-depth analysis of the prospects for universal access to modern energy by 2030.

There are however some aspects of the *WEO* that have not changed. One is the focus on objective data and dispassionate analysis. Another is the centrality of energy security, which is an important dimension of all the three main scenarios discussed in the *WEO-2017*.

Given that there is no single story about the future of global energy, the *WEO* continues to use a scenario-based approach to highlight the key choices, consequences and contingencies that lie ahead, and to illustrate how the course of the energy system might be affected by changing some of the key variables, chief among them the energy policies adopted by governments around the world. This approach continues to be underpinned by a system-wide modelling approach that covers all fuels, technologies and regions, providing insights into how changes in one area might have consequences (often unintended) for others.

The main scenarios in this *Outlook* are the New Policies Scenario, the Current Policies Scenario and the Sustainable Development Scenario. Described in more detail in the next section, they are differentiated primarily by the assumptions that they make about government policies. The New Policies Scenario is designed to show where existing policies as well as announced policy intentions might lead the energy sector. The Current Policies Scenario provides a point of comparison by considering only those policies and measures enacted into legislation by mid-2017. And the Sustainable Development Scenario, a new scenario in the *WEO-2017*, examines what it would take to achieve the main energy-related components of the "2030 Agenda for Sustainable Development" adopted in 2015 by member states of the United Nations. The three energy-related goals are: to achieve universal energy access to modern energy by 2030; to take urgent action to combat climate change; and to dramatically reduce the pollutant emissions that cause poor air quality.

References to all of the scenarios are interspersed throughout the chapters. However, the primary focus, as in past editions, is on the New Policies Scenario, which reflects both currently adopted measures and, to a degree, declared policy intentions. That this scenario enjoys most of the limelight in the *Outlook* is often taken as an implicit sign that this is – despite our protestations to the contrary – a forecast. However, the IEA does not have a long-term forecast (Spotlight).

New Policies Scenario

The New Policies Scenario is the central scenario of this *Outlook,* and aims to provide a sense of where today's policy ambitions seem likely to take the energy sector. It incorporates not just the policies and measures that governments around the world have already put in place, but also the likely effects of announced policies, as expressed in official targets or plans. The Nationally Determined Contributions (NDCs) made for the Paris Agreement provide important guidance as to these policy intentions in many countries, although in some cases these are now supplemented or superseded by more recent announcements – including the decision by the US administration to withdraw from the Agreement. Our reading of the national policy environment is also influenced by policies and targets adopted by sub-national authorities, i.e. by state-level entities in federal systems, by cities and municipalities, as well as the commitments made by the private sector (see the Spotlight in Chapter 3).

The way that policy intentions, including the NDCs, are reflected in the New Policies Scenario depends on the extent to which their realisation is supported by specific policies and implementing measures. Where these are in place, announced targets are assumed to be met, or indeed exceeded, where macroeconomic, cost or demand trends point to this. However, given that announced policy intentions are often not yet fully incorporated into legislation or regulation, the prospects and timing for their full realisation depend on our assessment of the institutional context and relevant political, regulatory, market, infrastructure and financing constraints.

Current Policies Scenario

The Current Policies Scenario excludes the realisation of announced, new policy targets and considers only the impact of those policies and measures that are firmly enshrined in legislation as of mid-2017. In addition, where existing policies target a range of outcomes, the assumption in the Current Policies Scenario is that the least ambitious end of this range is achieved. In this way, the scenario provides a cautious assessment of where momentum from existing policies might lead the energy sector in the absence of any additional impetus from governments. It therefore provides a reference against which the impact of any additional "new" policies can be measured.

Sustainable Development Scenario

The Sustainable Development Scenario is introduced for the first time in the *WEO-2017* and takes a fundamentally different approach from those discussed above. While the Current Policies and New Policies scenarios start with certain assumptions about policies and see where they lead the energy sector, the Sustainable Development Scenario (as with the previous 450 Scenario) starts with a certain vision of where the energy sector needs to go and then works back to the present. This vision of the future incorporates three major elements. First, it describes a pathway to the achievement of universal access to modern energy services by 2030, including not only access to electricity but also clean cooking.

Second, it paints a picture to 2040 that is consistent with the direction needed to achieve the objectives of the Paris Agreement, including a peak in emissions being reached as soon as possible, followed by a substantial decline.[2] Third, it posits a large reduction in other energy-related pollutants, consistent with a dramatic improvement in global air quality and a consequent reduction in premature deaths from household air pollution.

These three goals are interlinked and in many ways complementary. They reflect the key energy-related aspects of the United Nations Sustainable Development Goals (SDGs), including affordable and clean energy for all (SDG 7), action on climate change (SDG 13), as well as the efforts to reduce air pollution which are included under the goals for health (SDG 3) and cities and sustainable communities (SDG 11). These linkages are clear in the Paris Agreement, whose objective to strengthen the global response to the threat of climate change is explicitly framed in the context of sustainable development and efforts to eradicate poverty. In the same way, the NDCs of many developing countries make the connection between universal access and the implementation of their climate pledges.

Action on one of these goals can often assist in achieving another. For example, the universal provision of clean cooking facilities means a comprehensive shift away from the traditional use of solid biomass as a cooking fuel, and thereby also removes the main cause of household energy-related air pollution. The climate imperatives to deploy more efficient technologies and to reduce reliance on energy from fuel combustion – including through electrification of end-uses – have co-benefits in terms of lower pollutant emissions.

At the same time, there are potential trade-offs that have to be addressed. All else being equal, the achievement of universal access – even at relatively low levels of per capita consumption and widespread provision of access using low-carbon technologies – results in a slight increase in global CO_2 emissions. Even if the impacts are very small in global terms, this does require a modest extra effort elsewhere in order to compensate (an effort in which reductions in other greenhouse-gas emissions due to lower biomass consumption for cooking play an important role). Pollution control technologies for fossil fuel-fired power plants and large industrial facilities may help to improve air quality without reducing CO_2 emissions. Some modern bioenergy technologies may be suitable for reducing CO_2 emissions, but risk an increase in fine particulate matter that is damaging to human health.

The methodological approach adopted in the Sustainable Development Scenario is to focus first on universal access. Low-carbon technologies provide a suitable route in many instances to achieve energy access, not least because most of the population lacking

2. The temperature rise in 2100 associated with the Sustainable Development Scenario would depend on the point, in the second-half of this century, when the world reached a balance between anthropogenic emissions and their removal by sinks (by means of measures such as afforestation or carbon capture and storage). If this "net zero" emissions point targeted by the Paris Agreement is achieved right at the end of the century, in 2100, then this scenario has a roughly even chance of limiting the temperature rise to below 2 degrees Celsius. If this net zero point is achieved earlier in the second-half of the century, or if it is followed by a period of net negative emissions, the likely rise in temperature is lower. As described in Chapter 3, the Sustainable Development Scenario puts the world on a pathway that would be consistent with a range of such outcomes; we also present a Faster Transition Scenario which would increase the chances of a lower temperature rise.

electricity is in rural areas where decentralised energy solutions can be cheaper than grid extension. But this is not always the case: we consider all technologies and fuels in the analysis, including fossil fuels, as the contribution of achieving universal access to modern energy by 2030 to CO_2 emissions is small, and can be offset by declines in other greenhouse-gas (GHG) emissions. Developments in all countries are then modelled to remain within the required carbon constraint, guided by the policy and technology preferences that countries have today (but, in almost all cases, extending their reach). The mixture of technologies deployed to meet climate objectives is also shaped by the requirement to improve air quality.

Other scenarios and cases

Other scenarios and cases referred to in this report are:

- **Faster Transition Scenario**[3] **–** This scenario, developed in 2017, plots an emissions pathway to "net zero" energy sector CO_2 emissions in 2060 (see footnote 2), resulting in lower emissions than the Sustainable Development Scenario in 2040.
- **Low Oil Price Case –** This case, considered in Chapter 4, looks at the conditions that would allow the oil price to remain "lower for longer"; it updates the work done in the *WEO-2015* on a Low Oil Price Scenario.
- **Energy for All Case –** Developed specifically for the *WEO-2017,* this case examines the achievement of modern energy for all against the backdrop of the New Policies Scenario. It provides a point of comparison with the way that a similar goal is covered in the Sustainable Development Scenario.
- **450 Scenario –** This scenario was not modelled for the *WEO-2017*, but in recent *Outlooks* it has been the main decarbonisation scenario. Previous results are used on occasion for purposes of comparison.
- **Clean Air Scenario –** Introduced in a Special Report in the *WEO-2016* series[4], this set out a cost-effective strategy, based on existing technologies and proven policies, to cut 2040 pollutant emissions by more than half compared with the New Policies Scenario.
- **Bridge Scenario –** Featured in another Special Report, this time in the *WEO-2015* series[5], this put forward a bridging strategy, based on five specific energy sector measures, to achieve an early peak in energy-related CO_2 emissions.

3. This scenario was originally developed by the IEA in 2017 as a contribution to a joint study "Perspectives for the Energy Transition: Investment Needs for a Low-Carbon Energy System" with the International Renewable Energy Agency (IEA/IRENA, 2017); the work was supported by the government of Germany as input to the 2017 German G20 presidency. The report is available at *www.energiewende2017.com/wp-content/uploads/2017/03/Perspectives-for-the-Energy-Transition_WEB.pdf*.

4. The *WEO-2016* Special Report, *Energy and Air Pollution* (IEA, 2016) is available at: *www.iea.org/publications/freepublications/publication/weo-2016-special-report-energy-and-air-pollution.html.*

5. The *WEO-2015* Special Report, *Energy and Climate Change* (IEA, 2015) is available at: *www.iea.org/publications/freepublications/publication/weo-2015-special-report-2015-energy-and-climate-change.html*.

SPOTLIGHT

Why doesn't the IEA have a long-term forecast?

The scenario results presented in the *WEO* are sometimes mischaracterised as forecasts. They are not. Each scenario depicts an alternative future, a pathway along which the world could travel if certain conditions are met. The IEA does provide short- to medium-term forecasts for different fuels and technologies, but there are no long-term IEA forecasts; in our judgement, there are simply too many variables in play for this to be a viable approach.

One major uncertainty concerns policy. A central tenet of the New Policies Scenario is that it reflects only those policies that are either already in place or those that have been announced. As a scenario assumption this works well – it allows us to investigate the direction in which today's decision-makers are taking the energy system – and therefore to provide them with essential feedback on their choices and ambitions. But this would not be a sensible way to approach forecasting. There will undoubtedly be additional policy shifts between now and 2040, beyond those already announced by governments around the world. These could be in response to concerns about energy security (e.g. to offset rising import dependency) or affordability (e.g. to mitigate the effect of upward pressure on prices) or to temper rising emissions (e.g. via the commitment in the Paris Agreement to update pledges every five years with the intention to increase climate ambition). If we did forecast, we would try and second-guess these future responses.

A second area where there is major uncertainty is technological change. Our current modelling incorporates a process of learning-by-doing that affects the costs of various fuels and technologies, including the cost of investing in energy efficiency. However, while technology learning is integral to the *WEO* approach, the *WEO* does not try to anticipate technology breakthroughs as these are, by their nature, impossible to predict. Scenarios are the only way to try to understand the impact on the energy system of potential step-changes in the cost of different technologies.

Another uncertainty is the unpredictable boom-and-bust cycles to which parts of the energy sector are subject. Parts of the oil and gas sectors are currently in the low-price "bust" phase, and how and when these sectors rebalance is a major question for short- and medium-term forecasts. Attempting to model such cycles over the longer term would not only be challenging, but would also obscure the policy effects that we seek to examine. Instead, our *Outlook* projections consider an energy system that finds and retains equilibrium, i.e. it does not try to capture long-term cyclical dynamics. In reality, some markets might remain in disequilibrium for an extended period, e.g. if today's low levels of upstream investment eventually lead to a price spike that then produces a further over-correction and the start of a new cycle, and so on.

The bottom line is that, with so many uncertainties and so many moving parts, a forecast as far out as 2040 would be highly susceptible to intervening events. More than that, if we did try to forecast, we would be altering fundamentally the purpose of the *Outlook* and – we are convinced – reduce its utility. The aim of a forecaster is to be correct; presumably, forecasters celebrate when their predictions turn out to be true. Our aim is to illuminate and inform debate and decision-making. If the projections in our Current Policies Scenario or even our New Policies Scenario turn out to be true in 2040, this will not be a sign of success. Success for the *WEO* is about helping countries to achieve the long-term energy and related goals that they have chosen.

1.2 Developing the scenarios

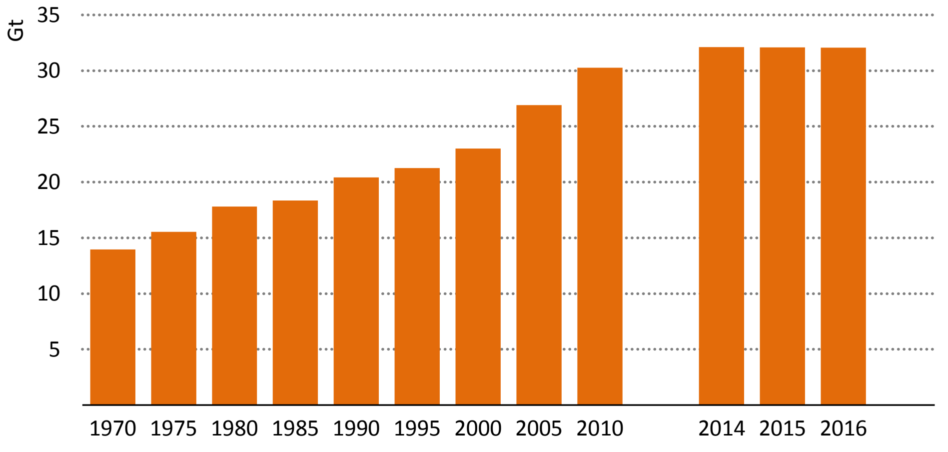
The starting point for all of the scenarios in the *WEO-2017* is the latest data on today's energy consumption, costs, prices and policies. The formal base year for this year's projections is 2015, as this is the last year for which a complete picture of energy demand and supply is in place, but we have used more recent data wherever available, and we include – for the first time – our 2016 estimates for energy production and demand in the annexes to this *WEO* that summarise the projections. The tables and discussion in the chapters typically refer to 2016 data, even if these are, in many cases, provisional.

What do these latest energy data show? They portray an energy sector in which demand patterns and traditional distinctions between consumer and producer countries are evolving rapidly (Box 1.2). They suggest significant market imbalances that are likely to maintain downward pressure on prices for some time to come: this is the case not only for oil and gas, but also for some other parts of the energy sector such as solar photovoltaic (PV) panels. They also show an energy system that is changing at considerable speed, with the dramatic falls in the costs of key renewable technologies upending traditional assumptions on relative costs.

While some global trends are unambiguous, it remains unclear in other instances whether we have reached genuine inflexion points, or whether there are cyclical and temporary factors involved that might be reversed with time. A critical uncertainty relates to energy-related CO_2 emissions, which have remained flat since 2014 (Figure 1.1). Multiple factors contributed to this outcome: the large expansion in low-carbon power generation, led by rapid deployment of wind and solar; a reduction in the energy intensity of global gross domestic product (GDP); and a fall in estimated global coal use, driven by developments in China and coal-to-gas switching in the United States. The question, examined in detail in this *Outlook*, is whether momentum in these areas can be sustained and, in turn, whether the next move for CO_2 emissions is up or down.

The answer to this question (and many others) varies across the different scenarios examined in this *Outlook*, underlining how changing key assumptions can put the entire energy system on a different future course. This also comes through clearly from a look back at previous *WEOs*, in particular at instances where things turned out differently from the projected outcomes. For example, initial *WEO* projections (in our then Reference Scenario) did not capture the eventual extent of the rise in China's coal consumption in the mid-2000s: the pace of GDP growth assumed in the modelling turned out to be lower than what China achieved in practice.

Figure 1.1 ▷ Global energy-related CO_2 emissions



Analysis of estimated 2016 data suggests another year of flat global CO_2 emissions, even though the global economy continued to grow

Note: Gt = gigatonnes.

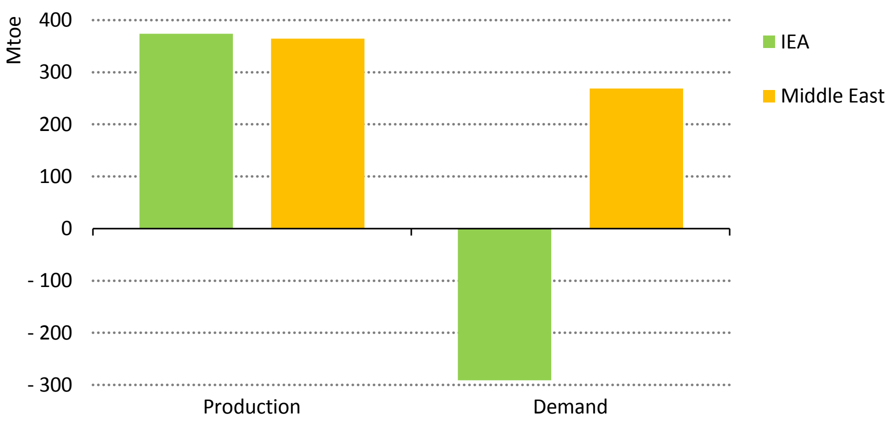
Box 1.2 ▷ A new way to look at the world of energy

The presentation of data and projections in the *WEO* has traditionally divided the world into OECD and non-OECD. This was the guiding principle for the country and regional groupings shown in the tables and annexes and, at least for some time, represented some important features of the global energy system. The OECD accounted for major energy-consuming regions of the world, including North America, Japan, Korea and large parts of Europe, all of whom were reliant – to greater or lesser degrees – on energy imported from other parts of the world, notably the Middle East and Russia.

This way of categorising the global energy system has been steadily becoming less meaningful. From 60% in 1977, the share of the OECD in global primary energy demand is now 39%. The powerhouses of global energy demand growth are elsewhere, led by the developing economies of Asia: this is indeed why the IEA has opened its doors to new players, with Brazil, China, India, Indonesia, Morocco, Singapore and Thailand, all now IEA Association countries. The customary producer-consumer division needs to accommodate the fact that, at least in recent years, a major share of global production growth has come from IEA countries, while some resource-rich regions – notably the

Middle East – are facing rapid increases in consumer demand (Figure 1.2). There are also global environmental challenges, whose resolution requires the development of more widely dispersed renewable resources and new models of energy co-operation. With all of these changes, this *Outlook* moves to a purely geographical presentation of results, and OECD and non-OECD aggregates are retained only for reference (in Annex A).

Figure 1.2 ▷ Change in total primary energy production and demand in IEA member countries relative to the Middle East, 2005-2015

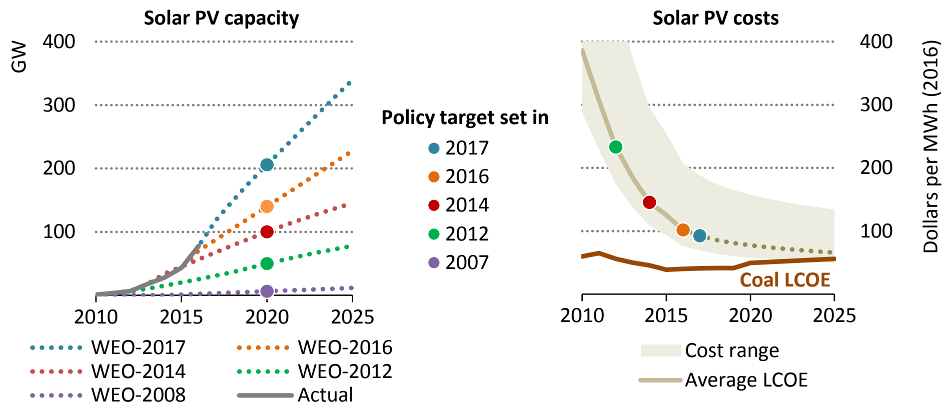


In a reversal of oft-assumed roles, IEA members increased energy production more than the Middle East in recent years

Notes: Mtoe = million tonnes of oil equivalent. Data for IEA considers membership status as of mid-2017.

In a similar way, the oft-commented projections in successive *WEOs* for wind and solar deployment reflected the policy and technology environment at the time that the projections were made. Taking China again as an example (since it has outsize influence on global solar PV trends), policies and targets have strengthened dramatically over the last ten years. The 2007 "Mid- to Long-Term Plan of Renewable Energy" set a target of 1.8 GW of total solar capacity for 2020 (reflected in the *WEO-2008*); in this edition, we are taking into account new guidance from the Chinese authorities that sets a cumulative upper target of 160 GW for utility-scale solar PV in 21 provinces (deployment in the rapidly growing distributed solar PV market is additional) (Figure 1.3). As these targets stepped up so our projections changed as well, with increased policy-driven deployment creating a virtuous circle – clearly visible in successive *WEO*s – of lower technology costs and higher policy ambition. In line with the methodology of the New Policies Scenario, we did not try to anticipate future changes in policy; however, we also recognise that – with sufficient support from policy – at a certain point costs fall to a level that is competitive with other forms of generation without subsidy; deployment then becomes far less reliant on specific policy targets. Solar PV in China is a good example: in the *WEO-2017*, the levelised costs of new solar PV are set to fall below those of new coal-fired power plants by the late 2020s.

Figure 1.3 ▷ **Evolution of China policy targets and projections for solar PV installed capacity, and solar PV levelised costs, in selected *WEOs***



The projections for solar PV in China in successive WEOs show the virtuous circle of policy-driven deployment & lower costs, bringing the technology to competitiveness with coal

Note: PV = photovoltaic; LCOE = levelised cost of electricity.

World Energy Model

The *WEM* generates the energy projections used in this report.[6] The *WEM* is a large-scale simulation tool, developed at the IEA over a period of more than 20 years. It is designed to replicate how energy markets function and covers the whole energy system, allowing for a range of analytical perspectives from global aggregates to elements of detail, such as the prospects for a particular technology or the outlook for end-user prices in a specific country or region. The current version models global energy demand in 25 regions, 12 of which are individual countries. Global oil and gas supply is modelled in 120 distinct countries and regions, while global coal supply is modelled in 31 countries and regions. The main modules cover energy consumption, fossil fuel and bioenergy production, and energy transformation (including power generation and refining), and there are supplementary tools that allow more detailed analysis of specific issues. The model is updated and enhanced each year and the major changes introduced for the *WEO-2017* include:

- Offshore energy production, for oil, gas and wind, has been modelled in more detail, including detailed hourly simulations of the evolving market value of offshore wind and more granular consideration of the outlook for different oil and gas resource types and water depths.

6. For details on the *WEM* methodology, see *www.iea.org/weo/weomodel*.

- A range of technologies and costs for reducing methane leaks along the oil and gas value chains are now included in the model, allowing for more detailed consideration of the costs and benefits of abatement.
- Additional detail on technologies and efficiencies in the road freight sector has been incorporated into the model, following an in-depth study.[7]
- Industrial energy use has been further disaggregated, allowing differentiation between demand for different temperatures of heat and related technology choices.
- For the special focus on China:
  - The hourly power generation model that was introduced in the *WEO-2016* to offer insights into the integration of variable renewables (including elements such as demand-side response and energy storage) has been extended to China, with six Chinese regions now modelled separately.
  - More disaggregation has been introduced into the services sector model to account for the energy consumption profiles of different types of commercial and public service buildings.

Other modelling has helped to generate additional insights. The outputs from the *WEM* have been coupled with the Greenhouse-gas – Air Pollution Interactions and Synergies (GAINS) model of the International Institute of Applied Systems Analysis (IIASA) to generate an outlook for air pollutants. The OECD computable general equilibrium model (ENV-Linkages) was used to assess the links between the economic transition in China and the energy outlook. The Open Source Spatial Electrification Tool (OnSSET) and the Open Source Energy Modelling System (OSeMOSYS) of the Swedish Royal Institute of Technology provided geospatial analysis of least-cost electricity generation options for energy access.

1.2.1 Inputs to the modelling

Energy policies

The policy actions assumed to be taken by governments are a key variable in the *Outlook* and the main reason for the differences in outcomes across the scenarios. An overview of the policies and measures that are considered in the various scenarios is included at Annex B. The "new policies" that are considered in the New Policies Scenario are derived from an exhaustive examination of announcements and plans in countries around the world. There have been some notable developments over the past year:

- The **United States** announced a new direction in energy policy. An Executive Order in March 2017 emphasised the importance of US energy resources for domestic economic growth and employment, and instructed relevant agencies to review existing regulations that potentially hinder the development of these resources, with a view to suspending, revising or rescinding them. The Executive Order includes a review of

7. See *The Future of Trucks: Implications for energy and the environment* (IEA, 2017) available at: *www.iea.org/publications/freepublications/publication/TheFutureofTrucksImplicationsforEnergyandtheEnvironment.pdf*.

the Clean Power Plan, the impact of which is now no longer considered in the New Policies Scenario. A number of state and city-level authorities however have pledged to continue support for low-carbon technology development and deployment, and the New Policies Scenario factors this in. The US also subsequently announced its decision to withdraw from the Paris Agreement on climate change, meaning that implementation of the US NDC commitments is likewise no longer part of the New Policies Scenario. The announcement on the Paris Agreement was accompanied by the stated intent for the United States to maintain a leadership position in clean energy.

- **China** released an Energy Production and Consumption Revolution Strategy (2016-2030), following the President's call in 2014 for an "energy revolution". This detailed measures to support the implementation of the 13th Five-Year Plan. The latter includes plans for coal, oil, gas, power, shale gas, coalbed methane, nuclear, hydropower, wind, solar, biomass, geothermal and energy technology innovation. Each of these plans identifies specific medium-term binding or indicative targets. The State Council has also issued guidance on the future direction of market reforms in the oil and gas sectors, following on from a similar document on the electricity sector issued in 2015. Air pollution remains the focus of many regulatory measures.
- **India's** government released a draft national energy policy that proposes a co-ordinated strategy to achieve announced national and sectoral policy goals. These include targets for electrification (universal "24x7" access for all by 2022); for a higher share of manufacturing in GDP and a reduction in oil imports; for 175 gigawatts (GW) of renewable capacity by 2022; as well as the NDC commitments to reduce the emissions intensity of the economy by 33-35% by 2030 (from the 2005 baseline) and to boost the share of non fossil-fuel capacity in the power sector to 40% over the same period.
- **Korea** announced a policy shift that will reduce the role of nuclear power and coal-fired plants in the generation mix, and support an expanded role for renewable energy technologies and natural gas.
- **Japan** began the liberalisation of its retail gas market in April 2017, following liberalisation of its retail power market the previous year. In the same month, it revised feed-in tariffs and introduced a new auction system for large-scale solar PV.
- The **European Commission** proposed a new "Clean Energy for All" package, which proposes new legislation on energy efficiency, renewables, the design of the electricity market, security of electricity supply and governance rules for the Energy Union.
- Some European countries announced plans to phase out coal-fired power completely, including **France** by 2023, the **United Kingdom** by 2025 and **Finland** by 2030.
- The **United Kingdom** and **France** both proposed an outright ban on sales of new diesel and gasoline vehicles by 2040.
- **Saudi Arabia** announced its intention to phase out most fuel subsidies by 2020, accompanied by measures to support vulnerable low-income households and to help industry with the transition.

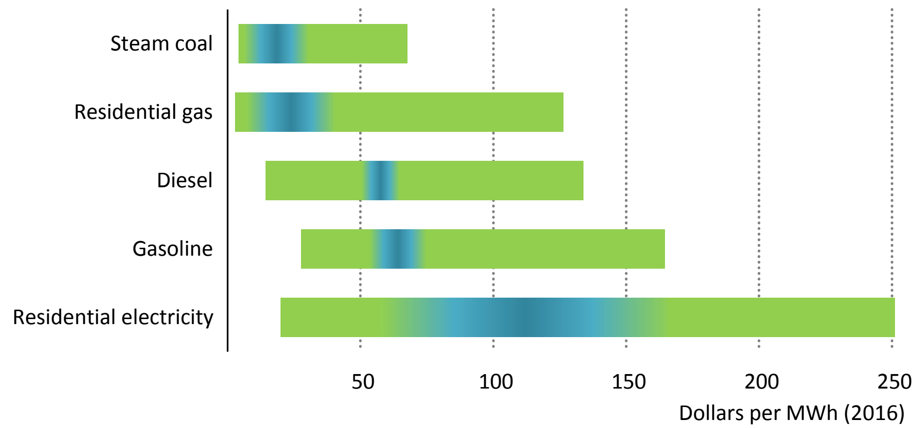
- **Qatar** lifted a self-imposed moratorium on development of its part of the world's biggest natural gas field that it shares with Iran (known as the North Field in Qatar, South Pars in Iran).

Pricing policies

Alongside policies, the prices paid for energy by end-users are a critical variable in determining patterns of consumption. Overall, relatively low international prices for fossil fuels (at least by recent standards) have exerted downward pressure on end-user prices; the range of end-user prices worldwide is nonetheless huge.

As demonstrated in Figure 1.4, in some parts of the world average end-user prices remain well below the relevant international benchmarks. In many cases this reflects fossil-fuel consumption subsidies, representing either an explicit effort to lower the price of an imported product for domestic sale, or the opportunity cost for a producer of pricing domestic energy below market levels (or a combination of the two). During a period of relatively low international prices, many countries have signalled their intent to remove fossil-fuel subsidies. However, their removal is not assumed in the Current Policies Scenario unless a formal programme is already in place. In the New Policies Scenario, net-importing countries and regions phase out fossil-fuel subsidies completely within ten years. In the Sustainable Development Scenario, while all fossil-fuel consumption subsidies are similarly removed within ten years in net-importing regions, they are also removed in all net-exporting regions, except some countries in the Middle East, within 20 years.

Figure 1.4 ▷ Range of prices paid by consumers for final energy, 2015



End-user prices for energy carriers vary widely around the world, due to underlying variations in delivered costs but also subsidies, taxes and other charges

Notes: MWh = megawatt-hour. The areas shaded in blue represent the range of reference prices used for the purposes of calculating energy consumption subsidies. Variations in quality may explain a part of the variations in price, especially for electricity where differences in reliability of services mean that it is not a homogenous product across countries.

Another influential policy variation between the scenarios is the scope and level of carbon pricing, which has a major impact on the relative costs of using different fuels. In addition to schemes already in place, which are assumed to remain throughout the period to 2040, the New Policies Scenario includes the introduction of new carbon pricing instruments where these have been announced but not yet introduced. In the Sustainable Development Scenario, the use of carbon pricing instruments becomes much more widespread, especially within the advanced economies, and prices are significantly higher (Table 1.1). An important change compared with last year's *Outlook* relates to Canada, where the Pan-Canadian Framework on Clean Growth and Climate Change includes the commitment to price carbon pollution across the country by 2018. The implementation of this commitment varies across the country and is subject to review in 2022.[8] It is modelled in our scenarios with the introduction of a carbon price for power, industry and aviation sectors in the Current Policies Scenario and for all sectors in the New Policies Scenario.

Table 1.1 ▷ CO_2 price in selected regions by scenario ($2016 per tonne)

	Region	Sector	2025	2040
Current Policies Scenario	Canada	Power, industry, aviation	15	31
	European Union	Power, industry, aviation	22	40
	Korea	Power, industry	22	40
New Policies Scenario	South Africa	Power, industry	10	24
	China	Power, industry, aviation	17	35
	Canada	All sectors	25	45
	European Union	Power, industry, aviation	25	48
	Korea	Power, industry	25	48
Sustainable Development Scenario	Brazil, China, Russia, South Africa	Power, industry, aviation*	43	125
	Advanced economies	Power, industry, aviation*	63	140

* Coverage of aviation is limited to the same regions as in the New Policies Scenario.

Economic outlook

Global economic activity is expected to pick up in the coming years, with an anticipated cyclical recovery in investment, manufacturing and trade. From global growth of 3% in 2016, growth rates are expected to rise to around 3.5% in 2018. This figure is close to the long-term global average that is assumed in this *Outlook*: in each of the scenarios, the world economy is assumed to grow at a compound average annual rate of 3.4% over the period

8. The approach provides jurisdictions the flexibility to implement either an explicit price-based system (a carbon tax such as the one in British Columbia), or a hybrid approach composed of a carbon levy and an output-based pricing system (such as in Alberta) or a cap-and-trade system (such as those in Quebec and Ontario). The federal government plans to put in place a backstop that would apply in jurisdictions that do not have a carbon pricing system in place.

to 2040 (Table 1.2). Overall, the global aggregates are quite similar to those of the *WEO-2016*, although there are some slight downward revisions for medium-term economic growth in some regions, notably for oil-exporting countries in the Middle East and Africa, reflecting the assessment from the International Monetary Fund (IMF, 2017).

Table 1.2 ▷ Real GDP growth assumptions by region

	Compound average annual growth rate			
	2000-16	2016-25	2025-40	2016-40
North America	1.8%	2.1%	2.1%	2.1%
United States	1.8%	2.0%	2.0%	2.0%
Central & South America	2.8%	2.3%	3.0%	2.8%
Brazil	2.4%	1.9%	3.0%	2.6%
Europe	1.7%	1.9%	1.6%	1.7%
European Union	1.4%	1.7%	1.4%	1.5%
Africa	4.4%	4.1%	4.4%	4.3%
South Africa	2.9%	2.1%	2.9%	2.6%
Middle East	4.4%	3.0%	3.5%	3.3%
Eurasia	4.1%	2.3%	2.7%	2.6%
Russia	3.4%	1.7%	2.4%	2.1%
Asia Pacific	6.0%	5.4%	4.0%	4.5%
China	9.2%	5.8%	3.7%	4.5%
India	7.2%	7.7%	5.7%	6.5%
Japan	0.8%	0.7%	0.7%	0.7%
Southeast Asia	5.2%	5.1%	4.0%	4.5%
World	**3.6%**	**3.7%**	**3.3%**	**3.4%**

Notes: Calculated based on GDP expressed in year-2016 dollars in purchasing power parity (PPP) terms. See Annex C for composition of regional groupings.

Sources: (IMF, 2017); World Bank databases; IEA databases and analysis.

The way that economic growth translates into energy demand growth varies substantially by country, depending on each country's economic structures and stages of development, as well as pricing and efficiency policies. In most advanced economies, energy demand is now on a path of gradual structural decline, despite continued growth in national output. Elsewhere, however, economic expansion has much stronger implications for energy demand, particularly in countries where energy-intensive industrial activity accounts for a larger share of GDP. For the global economy as a whole, as of 2016 a 1% rise in GDP is associated with a 0.3% increase in primary energy demand. The level of this demand increase has however reduced: as recently as 2000-05, a 1% increase in GDP meant an average 0.7% rise in energy use. The rate at which the energy intensity of the global economy improves is a critically important indicator.

Demographic trends

As in previous years, the *WEO-2017* uses the medium variant of the United Nations' projections as the basis for population growth in all scenarios (UNPD, 2015). The world population rises by 0.9% per year on average, from 7.4 billion in 2016 to 9.1 billion in 2040 (Table 1.3). This is a critical determinant of many of the trends in our *Outlook* and is naturally subject to a degree of uncertainty: the range in the UN projections for 2040 is from 8.5 billion to 9.8 billion. The fastest growth in population is in Africa, underlining the scale of the challenge to provide universal access to modern energy. By 2040, three-out-of-four people in the world are living either in the Asia Pacific region or in Africa.

Table 1.3 ▷ Population assumptions by region

	Compound average annual growth rate			Population (million)		Urbanisation rate	
	2000-16	2016-25	2016-40	2016	2040	2016	2040
North America	1.0%	0.8%	0.7%	487	570	81%	86%
United States	0.8%	0.7%	0.6%	328	378	82%	86%
Central & South America	1.2%	0.9%	0.7%	509	599	80%	85%
Brazil	1.1%	0.7%	0.5%	210	236	86%	90%
Europe	0.3%	0.1%	0.1%	687	697	74%	80%
European Union	0.3%	0.1%	0.0%	510	511	75%	81%
Africa	2.6%	2.4%	2.2%	1 216	2 063	41%	51%
South Africa	1.5%	0.7%	0.6%	55	64	65%	75%
Middle East	2.3%	1.7%	1.4%	231	321	69%	76%
Eurasia	0.4%	0.3%	0.1%	230	236	63%	67%
Russia	-0.1%	-0.2%	-0.3%	144	133	74%	79%
Asia Pacific	1.1%	0.8%	0.6%	4 060	4 658	47%	59%
China	0.5%	0.3%	0.0%	1 385	1 398	57%	73%
India	1.5%	1.1%	0.9%	1 327	1 634	33%	45%
Japan	0.0%	-0.3%	-0.4%	127	114	94%	97%
Southeast Asia	1.2%	1.0%	0.7%	638	763	48%	60%
World	**1.2%**	**1.0%**	**0.9%**	**7 421**	**9 144**	**54%**	**63%**

Sources: UN Population Division databases; IEA databases and analysis.

An increasing share of the global population is living in cities and towns, and the global urbanisation rate is projected to rise from 54% in 2016 to 63% in 2040. In absolute terms, this means an extra 1.7 billion people added to the urban population over the next 25 years – the equivalent of a new city the size of Shanghai about every four months. There are many different avenues for urbanisation, from new "smart" cities to the expansion of slum areas with limited access to basic services, but overall this transition has major implications for energy consumption: urbanisation accelerates the switch to modern fuels, the rise in appliance and vehicle use, and demand for construction materials, including energy-intensive products such as steel and cement.

1.2.2 International prices and technology costs

Energy price trajectories and the evolution of costs for various energy technologies are generated within the *WEM* for each of the scenarios. Energy prices, in particular, are a major element of uncertainty. In each of the scenarios, the international prices for oil, natural gas and coal need to be at a level that brings the long-term projections for demand and supply into balance, avoiding either surfeits or shortfalls in investment: multiple model iterations are typically required to meet this condition. These are not price forecasts.

Since they keep supply and demand in each fuel and scenario in equilibrium, the price trajectories shown in Table 1.4 are smooth and do not attempt to track the fluctuations that characterise commodity markets in practice. By avoiding any new boom-and-bust cycles, the scenarios therefore skirt what is – in the view of the IEA – a significant vulnerability in today's energy markets. In the case of oil, where the risks appear to be greatest, there is an imbalance in upstream investment between a very dynamic shale sector in the United States and a slump in activity in many other parts of the oil sector. Indeed, these two phenomena are arguably related: the recent cost reductions in US shale production and its ability to respond relatively quickly to price upswings in the market – including those arising from the Organization of Petroleum Exporting Countries' attempts at market management – may be keeping short-term prices at levels that deter some necessary investments in other oil projects with longer lead times. Where the oil market finds its new balance depends to a significant degree on what happens with costs, both for tight oil and for other types of projects (see Chapter 4 for a detailed discussion).

The future evolution of the costs of producing all fossil fuels is determined within the *WEM* as a result of the interplay of three key factors. Technology learning and efficiency improvements continually exert downward pressure on costs; a deterioration in resource quality offsets this, as producers work their way through the resource base in a given area, which pushes costs up; meanwhile the cost of services and supplies can move up or down depending on the price of other materials (cement, steel, etc.) and the tightness of the market for skilled specialists and other equipment, e.g. rigs. In our scenarios, we make the simplifying but historically justifiable assumption that the cost of these services and supplies is correlated with movements in oil prices. The balance between these variables, and therefore the future trajectory of production costs, varies across different resource types and countries, and indeed across the different scenarios in this *Outlook*.

A similar process of technology improvement determines the future cost evolution of other energy technologies, both those in use today and those that are judged to be approaching commercialisation. The rapid cost decline for key renewable technologies is a critically important global energy trend, and the future evolution of costs for renewables, batteries, efficient electric motors and other new low-carbon technologies could fundamentally alter the long-term evolution of energy markets. In the *Outlook*, we do not make allowance for technological breakthroughs, as their timing and form are inherently unpredictable, but the process of continuous technology learning nonetheless has a major impact on our projections. The rate of improvement is related in many cases to the level of deployment;

it can therefore differ substantially by scenario. As in the case of fossil fuels, downward pressure on costs from technological improvements can be offset in some cases by depletion effects: this is a discernible factor affecting renewable resources in some countries and regions, for example, where the most advantageous sites for wind turbines have been fully exploited and developers have to look to second-tier sites. Overall, however, the trends in costs across the energy sector reinforce policy preferences for lower carbon energy options: oil and gas gradually become more expensive to extract, while the costs of renewables and of more efficient end-use technologies continue to fall.

Table 1.4 ▷ Fossil-fuel import prices by scenario

				New Policies				Current Policies		Sustainable Development	
Real terms ($2016)	2000	2010	2016	2025	2030	2035	2040	2025	2040	2025	2040
IEA crude oil ($/barrel)	38	86	41	83	94	103	111	97	136	72	64
Natural gas ($/MBtu)											
United States	5.9	4.8	2.5	3.7	4.4	5.0	5.6	4.3	6.5	3.4	3.9
European Union	3.8	8.2	4.9	7.9	8.6	9.1	9.6	8.2	10.5	7.0	7.9
China	3.5	7.4	5.8	9.4	9.7	10.0	10.2	10.4	11.1	8.2	8.5
Japan	6.4	12.1	7.0	10.3	10.5	10.6	10.6	10.8	11.5	8.6	9.0
Steam coal ($/tonne)											
United States	37	63	49	61	61	62	62	62	67	56	55
European Union	46	101	63	77	80	81	82	81	95	67	64
Japan	44	118	72	82	85	86	87	86	101	71	68
Coastal China	34	127	80	87	89	90	91	90	101	78	77

Notes: MBtu = million British thermal units; LNG = liquefied natural gas. The IEA crude oil price is a weighted average import price among IEA member countries. Natural gas prices are weighted averages expressed on a gross calorific-value basis. The US gas price reflects the wholesale price prevailing on the domestic market. The EU and China gas prices reflect a balance of pipeline and LNG imports, while the Japan gas price is solely LNG imports; the LNG prices used are those at the customs border, prior to regasification. Steam coal prices are weighted averages adjusted to 6 000 kilocalories per kilogramme. The US steam coal price reflects mine-mouth prices (primarily in the Powder River Basin, Illinois Basin, Northern Appalachia and Central Appalachia markets) plus transport and handling cost. Coastal China steam coal price reflects a balance of imports and domestic sales, while the EU and Japanese steam coal price is solely for imports.

Oil prices

The long-term oil prices in all the scenarios of the *WEO-2017* are lower than in last year's *Outlook*. In the New Policies Scenario, the reduction is strongest in the period to 2025, by which time the oil price reaches $83/barrel (in year-2016 dollars) before rising to reach $111/barrel by 2040 (respectively $18 and $14/barrel lower than in the *WEO-2016*). This adjustment reflects three main factors:

- First, a substantial upward revision in the resource estimate for technically recoverable tight oil and natural gas liquids in the United States. US tight oil is some 30% higher in this year's *Outlook* (up from 80 billion barrels to 105 billion barrels of crude and condensate). There is still considerable uncertainty over this estimate and, in a Low Oil Price Case, we test the implications of a much higher tight oil resource estimate of 210 billion barrels.

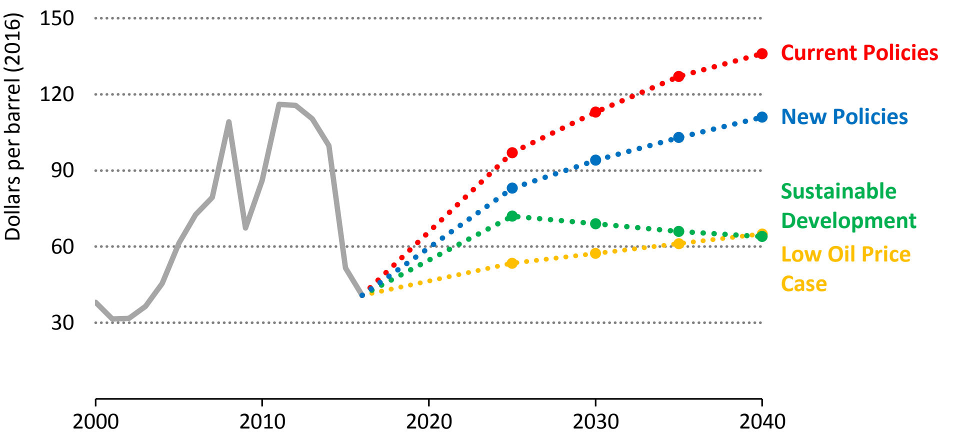
- Second, a reduction in the cost outlook for a variety of upstream projects, which means that more oil can be brought to market at lower prices than in the past. In North American shale, there has been a significant cost reduction effect from technology and efficiency gains, and through rationalising acreage ownership via mergers and acquisitions. On the conventional side, some projects that had been considered to have full-cycle breakeven costs in the range of $70-80/barrel as recently as 2014 are now claimed as viable at $30-50/barrel. A significant share of these reductions could yet prove cyclical and are reversed in the New Policies and Current Policies scenarios as prices rise, investment picks up and markets for supplies and services tighten. However, in our estimation, some of the cost reductions since 2014 are also of a structural nature, due in part to more efficient and standardised processes and project designs and to a degree of technological change over and above the technology learning that is built into the model.
- Third, a greater share of shorter cycle investments on the supply side. In the past, we have argued that the price for oil is always likely to be higher than the cost of the marginal barrel, because the market never quite reaches a classical equilibrium. This reflects a number of factors, including constraints on investment in some key resource-owning countries, and the need to take into account geopolitical risks. But one additional consideration was the long timescales of new projects, where uncertainty over future market conditions and other bottlenecks (notably the availability of sufficient skilled personnel) meant that investment decisions and production rates were always liable to fall behind the level required to keep pace with demand. However, the last few years have seen a definite shift towards shorter project timelines and investment cycles; to the extent that this is maintained in the future, it becomes easier for supply to follow demand quickly and therefore for price to get closer to the cost of the marginal barrel.

There remains an upward drift in the oil price over the period to 2040 in the New Policies Scenario, one that is even more pronounced in the Current Policies Scenario (where demand is significantly higher). This is due to the large requirement for new resource development: some 670 billion barrels in the New Policies Scenario to 2040, most of which is needed to compensate for declines at existing fields. The need to move to higher cost oil in more challenging and complex reservoirs, such as additional deepwater projects and smaller marginal onshore fields, and to less productive areas for tight oil production, means that the marginal project required to balance the market becomes steadily more expensive in this scenario, despite continued technological progress.

Market dynamics and price trends are however quite different in the Sustainable Development Scenario. In this scenario, the resilience of US tight oil means that the up-cycle that is visible in the New Policies Scenario does not have time to play out before demand peaks around 2020. This limits the call on higher cost oil to balance the market and the price therefore stays "lower for longer". We have revised downwards the equilibrium oil price for this scenario significantly compared with the 450 Scenario in the *WEO-2016*.

Another set of conditions under which oil prices could remain lower than in our central scenario is examined in a Low Oil Price Case (see Chapter 4). This analysis is derived from the New Policies Scenario, but changes some key assumptions in a way that keeps the oil price trajectory flat at around $50/barrel until the mid-2020s, before rising slowly to $65/barrel in 2040 (Figure 1.5). The main changes, relative to our central scenario, are a much more rapid growth of electric cars, a doubling of the assumed size of the US tight oil resource base, more rapid technology learning in the upstream and a favourable assumption about the ability of the main oil-dependent producing regions to weather the impact of lower hydrocarbon revenues.

Figure 1.5 ▷ Average IEA crude oil import price by scenario and case



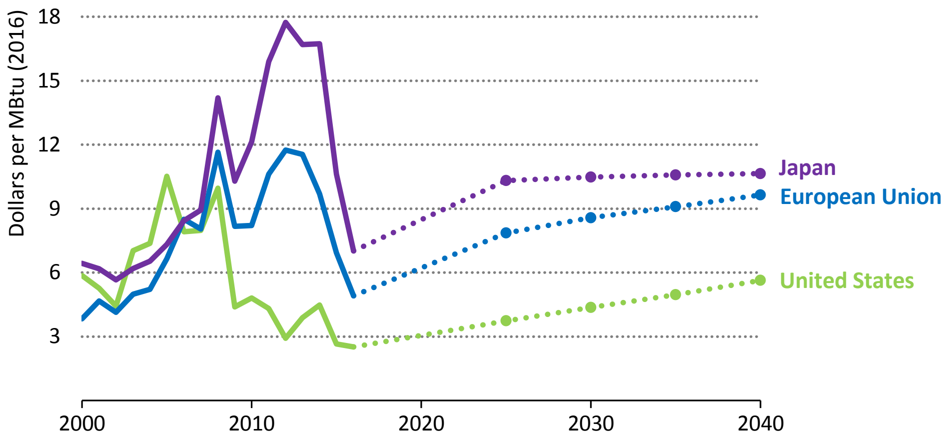
Oil prices vary widely by scenario, reflecting the different ways in which resources, costs and policies could affect the supply-demand balance

Natural gas prices

Like oil prices, natural gas prices in the *WEO-2017* are lower than in last year's *Outlook*. However, there is no single global price for gas, as there is for oil (Figure 1.6). Instead we have a range of regionally determined prices, all with their own specificities, that become gradually more interlinked as we move towards a more interconnected global market, driven by the increasing share of liquefied natural gas (LNG) in global trade, and by the increasing flexibility of this trade to seek the most advantageous commercial destination

The price trajectory for North America plays a critical role in our formation of global prices. The reference price is that of Henry Hub, a distribution hub in the US pipeline system in Louisiana where the price is set entirely by gas-to-gas competition, i.e. it is a price that balances regional supply and demand (including demand for gas for export). The projected price at this hub is lower in each scenario than in the *WEO-2016*. As with oil, this reflects an increase in the resource estimate for shale gas in the United States, and lower assumed costs for its production (see Chapter 9). It also reflects larger volumes of associated gas as a result of higher anticipated tight oil production.

Figure 1.6 ▷ Natural gas prices by key region in the New Policies Scenario



Natural gas prices in the main regions are connected by an increasingly flexible global trade in LNG

Note: See Table 1.4 for more details on natural gas price definitions.

The current period of ample supply in gas markets, alongside the low level of oil prices, has brought down prices in all the major markets, even though the way that gas prices are determined varies by region. In the case of Europe, an increasing share of imported gas is priced off trading hubs, particularly in north-western Europe, but a sizeable residual volume concentrated in southern and south-eastern Europe has prices indexed in full or in part to oil product prices. In Asia, oil-indexation still remains the norm for most imported gas, but new contracts in many parts of the region are weakening this linkage by including references to other indices, including the US Henry Hub.

In our projections, we assume movement in the direction of an integrated global gas market, in which internationally traded gas moves in response to price signals that are determined by the balance of gas supply and demand in each region, i.e. by gas-to-gas competition, and the differences between regional prices reflect only the costs of transporting gas between them. In this new, more liquid market, described in more detail in the special focus on natural gas (see in particular Chapter 9), large US resources and production flexibility, combined with an LNG export industry actively seeking arbitrage opportunities, make Henry Hub not only a regional but also an important global reference for gas price formation. Exporters trying to sell gas at a level above the delivered cost of US supply ultimately find themselves priced out of the market.

Profitable export opportunities from the United States are constrained for the moment by the global supply glut. As markets find a new equilibrium in the 2020s, however, European average import prices settle at around $4/MBtu (in year-2016 dollars) above the Henry Hub price in all scenarios, a differential that reflects the cost of delivering US gas to exporting terminals together with liquefaction and shipping costs. Oil-linked pricing is stronger in Asia than elsewhere, but this link weakens and in Japan the differentials from the US price fall to around $5/MBtu (the additional sum, compared with Europe, reflecting the extra shipping distance to Asian markets).[9]

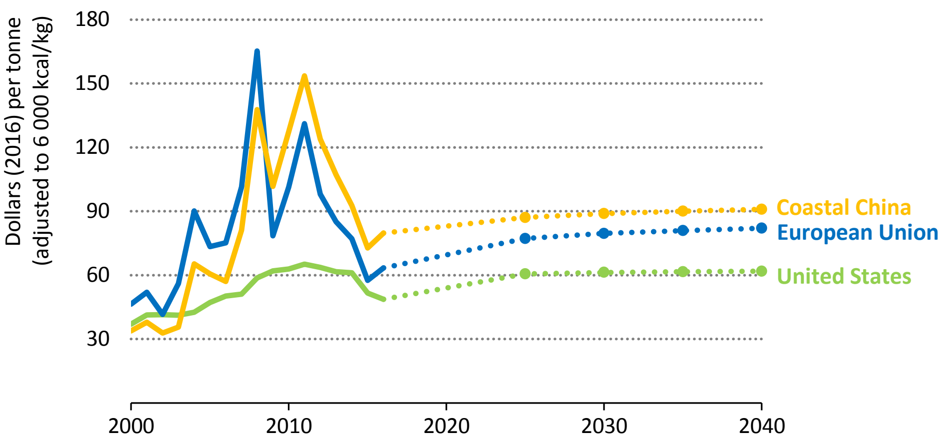
Coal prices

As in the case of natural gas, there is not a single global coal price but various regional coal prices that are usually closely correlated. The difference between the regional coal prices reflect the transport cost between locations, infrastructure bottlenecks and differences in coal quality. Although coal pricing follows market-based principles in most major coal producing countries, there are a few notable exceptions. In India, the state-owned coal giant Coal India Limited maintains a system of regulated “notified” prices. And in South Africa, the state-owned utility Eskom procures its coal needs through long-term contracts on a cost-plus basis from the mines. Although most of the coal trade in these countries is disconnected from the ups and downs of the international market, spot sales are on the rise in both of them, gradually introducing a market-based element in their coal pricing. We see this evolution continuing over the *Outlook* period, with coal pricing in both countries moving towards coal-to-coal competition in the long term.

Coal prices declined for four consecutive years before bottoming out in early 2016, at less than half the levels they reached in 2011. The price slump was caused by massive overcapacity from the building of new capacity when prices were high. Despite cost cutting, the drop in prices has put many coal companies around the world in a tight corner, forcing them to close mines or even go into bankruptcy. This consolidation process has contributed to the bottoming out of prices, together with the capacity cuts administered in China (see Chapter 14 for detail). We believe that Chinese coal prices will continue to be subject of state interventions for the next few years, and that measures to allow flexible adjustment of China’s coal output and fine-tuning of price movements will aim at a price range in China of $80/tonne to $90/tonne, with the aim of balancing the needs of China’s coal producers and consumers. This price range serves as important guidance for our price outlook for the coming ten years, with coastal China prices rising to $87/tonne in 2025 (Figure 1.7). Similarly, Japanese and European coal prices increase to $82/tonne and $77/tonne respectively in 2025.

9. The continued differentials in average import prices between Japan and China shown in Table 1.4 reflect the additional shipping distance for LNG to Japan, compared with the main Chinese LNG terminals and the slightly lower projected border prices for Chinese pipeline imports, especially those from Central Asia.

Figure 1.7 ▷ Steam coal prices by key region in the New Policies Scenario



Steam coal prices recover from recent lows, but the long-term trend remains markedly below historical highs

Notes: kcal/kg = kilocalorie per kilogramme. See Table 1.4 for more details on steam coal price definitions.

In the long term, worsening geological conditions, declining coal quality in mature mining regions, and longer transport distances in new mining regions combine to put modest upward pressure on coal prices. Mining costs are also increasing as cyclically low prices for consumables like fuel, explosives and tyres are trending upwards. By 2040, Chinese coal prices stand at around $90/tonne in our projections, while those in Japan and the European Union reach $87/tonne and $82/tonne respectively. Although Chinese coal imports decline over the *Outlook* period, arbitrage opportunities between domestic and imported coal remain key for coal pricing, and so the cost of bringing additional domestic coal to China's southern coast continues to act as a price ceiling for international coal prices.

Technology innovation, deployment and costs

The pace of technology change and innovation has the potential to alter fundamentally the future orientation of the energy system. This applies not only to low-carbon energy technologies, but also in some instances to fossil fuels. A reminder of this came in 2016 when the largest reduction in cost was not in wind or solar, but in the cost of producing tight oil in the United States.

Much current research and policy support is concentrated on low-carbon energy technologies and key issues for the *Outlook* period include: which clean energy technologies might be best placed to gain momentum; how deep an impact the increasing application of information and communications technologies might have in the energy sector (Box 1.3); and, at the other end of the spectrum, which energy technologies might be in danger of being left behind.

Box 1.3 ▷ How might digitalisation affect the future of energy?

Digital technologies are becoming ubiquitous, driven by declining costs of sensors and data storage, faster and cheaper data transmission, and rapid advances in analytical computing capabilities. The use of digital technologies across the economy – "digitalisation" – could have significant implications for energy demand and supply, and could bring about potentially transformational changes in both established energy systems and in fast-growing economies (IEA, 2017).

In residential and commercial buildings, for instance, widespread adoption of digitally enabled smart thermostats and smart lighting could reduce energy use in this sector by up to 10% by 2040 compared with the New Policies Scenario. In industry, technologies such as 3D printing could yield significant energy savings within and outside the sector (e.g. by reducing demand for international freight and shipping). On the supply side, digitalisation could bring down the costs of new oil and gas developments and bring new resources into play (see the Low Oil Price Case in Chapter 4).

The transformative potential of digitalisation is greatest in the power sector, given the progressive electrification of the energy system and the need to integrate more decentralised and variable sources of power. For instance, if 1 billion households actively participate in demand-side programmes and 11 billion smart appliances are connected to the grid, we estimate that nearly 185 GW of demand-side flexibility could be deployed cost-effectively by 2040. This would increase the capacity of the power system to respond to changes in electricity supply and demand – removing the need for around $270 billion in new electricity infrastructure investment and facilitating a higher share of wind and solar in the mix. Digital technologies could also save on the electricity supply side by reducing operation and maintenance costs, improving power plant and network efficiency, limiting unplanned outages and extending the operational lifetime of assets.

While digital technologies enable efficiency opportunities across the energy system, the data centres, data transmission networks and connected devices that underpin the burgeoning digital economy are also an important source of energy demand. Data centres and networks already account for about 2% of global electricity use, and this could increase as demand for their services rises. Energy efficiency trends in this area will be an important variable for projecting future electricity consumption.

Given the rapid pace of technological change, and uncertainty in behavioural response, the impacts on longer term energy trends are still quite uncertain (and, for that reason, are only incorporated in part into our projections). For instance, in road transport, automated and shared mobility could improve safety and efficiency, and smart charging of electric vehicles could also reduce the need for new power infrastructure. However, under a different set of assumptions, highly automated vehicles could also increase demand for mobility and push up energy use and emissions.

The benefits of digitalisation come with their own set of risks, requiring active management of the digital transition. Chief among these are potentially increased vulnerability to cyber-attacks as well as data privacy and data ownership issues. Both the opportunities and the risks created by the intersection of energy and digitalisation need increased attention from policy-makers.

A review of the current state-of-play for different clean energy technologies reveals some striking differences. Deployment of solar power had another very strong year in 2016, with record low long-term contract prices in Asia, Latin America and the Middle East. In 2016, solar PV annual additions surpassed those of wind power for the first time, with more than 70 GW coming on line, some 50% higher than the previous year. China accounted for around half of global solar PV additions and deployment in 2017 has remained very strong.

Global additions of wind power fell in 2016, compared with 2015. This was largely due to developments in China, which connected 19 GW of new onshore wind capacity, down significantly on the 33 GW seen the previous year. China cut its feed-in tariff in the meantime, but the fall in deployment also reflected difficulties that China has faced absorbing new wind power capacity in some regions: roughly 50 terawatt-hours (TWh) of potential wind generation was curtailed in 2016 because the power system could not accommodate it. These developments underline the continuing challenges of integrating wind (and other variable renewables), but the falling costs of wind power means that future prospects remain promising.

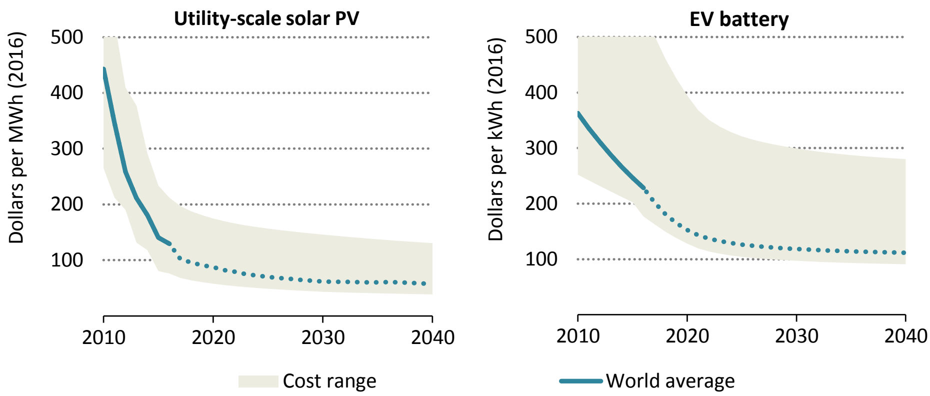
The global average levelised cost of electricity (LCOE) from utility-scale solar PV projects (weighted by deployment) declined by 70% from 2010 to 2016.[10] Over the projection period, this indicator declines by an additional 60% to 2040, although there is a wide range of regional averages both in the historical data and in our projections, reflecting different regulatory frameworks, delivered solar PV module costs and other costs including land, labour and supporting infrastructure (Figure 1.8). The assumed rate at which costs decline for solar PV in the future also varies slightly depending on local conditions, but in general it is around 20% for each doubling of cumulative installed capacity.

Another technology on the move is electric vehicles (EVs). In 2016, more than 750 000 electric cars were sold worldwide, taking the global stock to more than 2 million. As with some other low-carbon technologies, China is leading the way with almost half of global electric car sales (China is also the undisputed champion of electric scooters). For the moment, worldwide sales continue to be dependent on supportive policies and incentives and, where these were reduced, sales have often been badly affected: for example, electric car sales in Denmark collapsed in 2016 after

10. LCOEs represent only the direct costs of projects in real terms, they do not include system integration costs or other system costs that may be related to the deployment of solar PV. A standard weighted average cost of capital is applied to all projects (between 7-8% in real terms, depending on the region), though the availability of low-cost financing may enable developers to achieve lower levelised costs.

the phase-out of a tax break (it has since been partially reinstated). Overall, though, cost trends and policy support for EV deployment have become more favourable since the *WEO-2016,* and this is reflected in higher penetration in the New Policies Scenario.

Figure 1.8 ▷ Evolution of global average cost for selected technologies in the New Policies Scenario



Reductions in costs of key technologies continue to give strong impetus to the energy transition

Note: PV = photovoltaic; EV = electric vehicle.

The key technology variable for EVs is the cost of batteries, given the significant share of batteries in total EV cost (see Chapter 2, section 2.8). Two types of battery are considered in our assumptions: those for battery electric vehicles (BEVs), and those for plug-in hybrid electric vehicles (PHEV), which have slightly different characteristics and requirements. Since 2010, EV battery costs have been coming down at an annual rate of around 7% for major manufacturers, and the deployment that we project in the New Policies Scenario sees continued substantial reductions – at around 6% per year on average – until 2025. The decrease in costs then levels off as it closes in on the ambitious floor costs that we assume of $80 per kilowatt-hour (kWh) for BEV batteries and $100/kWh for PHEV batteries.

Among other critical technologies, batteries are also important for energy storage, which is showing some promising signs. This is an area that continues to be dominated by pumped-storage hydropower, but over 500 MW of other capacity was added in 2016, primarily lithium-ion batteries. Battery storage is still a relatively expensive option to provide flexibility to power systems, but it is starting to grow both at utility-scale and (particularly in countries with significant solar PV capacity) in the nascent market for behind-the-meter storage installations.

The recent record for carbon capture and storage (CCS) has been more mixed. On the positive side, the Petra Nova project in the US state of Texas, commissioned in 2017, retrofitted post-combustion capture technology on an existing coal-fired power station – a vitally important model for the future if operation of today's relatively young global coal-fired fleet is to be compatible with a low-emissions future. Another important step was the world's first large-scale CCS project in the iron and steel industry, which commenced operation in Abu Dhabi. Yet, overall, the global portfolio of CCS projects is not expanding at anything like the rate that would be needed to meet long-term climate goals. The decision in June 2017 to suspend start-up activities for the Kemper gasification system in the United States, due to the project's economics, is a reminder of the challenges that first-of-a-kind technology faces.

The picture for nuclear power is similarly mixed. On the one hand, commissioning of new capacity was up in 2016 to 10 GW, the highest level since 1990. However, the amount of capacity that started construction in 2016 was only 3 GW, well below the recent average. Nuclear plants, especially those in the United States, are struggling to keep a foothold in liberalised markets where competition is fierce. Korea, one of the four previous pillars of growth in projected nuclear capacity in previous *WEOs* (alongside China, India and Russia), has announced a review of its plans. The policy and technology landscape continues to change – and our projections in the *WEO* change in response.

Overview

Ten take-aways from the *WEO-2017*

Introduction

There are four large-scale shifts happening in global energy that provide a backdrop to our new *Outlook*:

- Deep **declines in the costs of major low-carbon technologies**, as described in the previous chapter. Together with the policies that have enabled these declines, this is opening up new opportunities to meet the world's energy needs in ways that are both sustainable and cost-effective, especially in the power sector.
- The **increasing importance of electricity** in global energy use, including encouraging progress with access to electricity in many countries and the electrification of new end-uses, for example via electric vehicles.
- The profound changes underway in **China's economy and energy policy**, which are transforming the way that China affects global energy markets.
- The rapid growth that we continue to see in **shale gas and tight oil in the United States**, with wide-ranging impacts on prices, trade flows and energy security.

How these four shifts play out and interact over the coming decades is central to this year's analysis. In this chapter, we pull together different aspects of our analysis of these issues, and bring out other key insights from the various *World Energy Outlook (WEO)* chapters that follow, to answer ten questions on the future of energy:

1. How much energy does the world need, and where?
2. Where now for energy in the United States?
3. What does China's "energy revolution" mean for its energy outlook, and for the world?
4. What is the next move for energy-related CO_2 emissions?
5. How much do energy policies matter?
6. Are new technologies bringing us closer to universal access to electricity?
7. Is natural gas a fuel in good shape for the future?
8. Can oil prices stay lower for much longer?
9. Is the future switching towards electricity?
10. Is offshore energy yesterday's news or tomorrow's headlines?

2.1 How much energy does the world need, and where?

Looking for the energy consumers of tomorrow is a search that can lead in different directions. If the question is about growth in demand, relative to today, then the trail leads quickly in the New Policies Scenario to some key emerging economies, notably India, China and Southeast Asia, but also the Middle East, parts of Africa and Latin America. As the global population rises to more than 9 billion people in 2040, a steady increase in energy needs of 1% per year on average means that – by 2040 – primary energy demand is almost 30% higher than today (Table 2.1). Put another way, in the New Policies Scenario, the world is set to add the equivalent of today's China plus India to its energy demand by 2040.

Developing economies in Asia represent around two-thirds of this growth. China remains the world's largest energy-consuming country, but the largest contribution to the increase in global demand – almost 30% – comes from India, where rising incomes and population push energy demand up by 1 000 million tonnes of oil equivalent (Mtoe) between now and 2040. Southeast Asia is another rising heavyweight in global energy, with demand growing at twice the pace of China.[1] By contrast, some advanced economies see their overall energy needs fall back in the New Policies Scenario: demand in Europe in 2040, for example, is 10% lower than today. So while Europe's share of global demand (15%) in 2016 was double that of India (7%), by 2040 the rankings are reversed as India moves up to a share of 11% while Europe, with a population well under half as large, falls back to 10%.

If, on the other hand, the search is for the largest energy consumers on a per capita basis, the focus shifts towards North America, parts of Eurasia, to the advanced economies of Asia and to the Middle East. These consumers are characterised either by high incomes (in Australia, Canada, Japan, Korea, United States), high heating needs (especially in Russia and Canada) or fossil-fuel subsidies that encourage wasteful consumption (particularly in the Middle East and Russia, although efforts at pricing reform have accelerated in recent years). In the New Policies Scenario, there is some modest convergence in global per capita consumption levels, which rise in India (by 70%), Southeast Asia (40%) and Central and South America (20%). In the case of China, this is sufficient for average per capita consumption to overtake that of Europe (Figure 2.1). Nonetheless, in this scenario, the problem of incomplete access to energy remains: 675 million people, largely in rural areas of sub-Saharan Africa, remain without access to electricity in 2030.

Another approach is to consider where energy consumers are living: the answer, increasingly, is in cities and towns. In 2007, the number of people living in urban areas worldwide exceeded those in rural areas for the first time and, by 2016, the share of the urban population had grown to 54% and accounted for some two-thirds of global primary energy demand (IEA, 2016). By 2040, our projections anticipate that a further 1.7 billion people will join the urban population (more than 90% of the increase taking place in developing economies), a shift with enormous implications for energy use. This means a transition away from solid fuels

1. *Southeast Asia Energy Outlook 2017*, *World Energy Outlook Special Report* provides in-depth analysis of the prospects for this region and is available at *www.iea.org/southeastasia/*.

(biomass and coal) to electricity, gas and oil products; generally higher urban incomes also translate into higher ownership rates for appliances; and the need to house millions of new urban inhabitants spurs demand for a range of energy-intensive products, especially steel and cement. However, there is no pre-set pathway for urban consumption: cities also have the potential to push electrification in new ways through electric vehicles, heat pumps and digital control technologies. Much depends on the way that public policy, urban design and infrastructure investment shape urban energy choices.

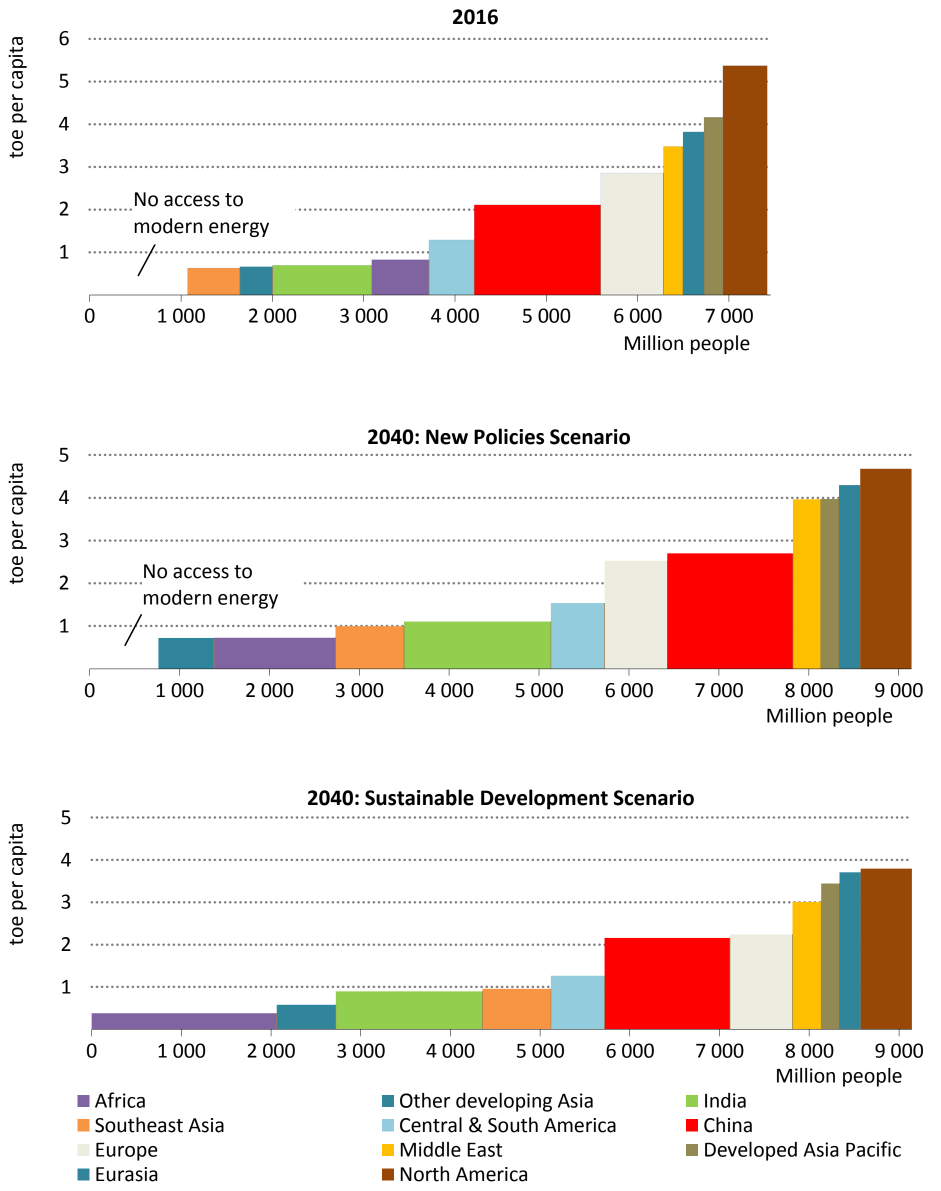
Table 2.1 ▷ World primary energy demand by region in the New Policies Scenario (Mtoe)

							2016-2040	
	2000	2016	2025	2030	2035	2040	Change	CAAGR*
North America	2 678	2 615	2 672	2 660	2 652	2 668	53	0.1%
United States	2 270	2 154	2 188	2 162	2 132	2 122	- 32	-0.1%
Central & South America	449	666	736	794	863	936	270	1.4%
Brazil	184	290	319	345	375	405	115	1.4%
Europe	2 028	1 965	1 887	1 831	1 784	1 762	- 203	-0.5%
European Union	1 693	1 594	1 485	1 414	1 350	1 312	- 282	-0.8%
Africa	501	804	953	1 056	1 166	1 289	486	2.0%
South Africa	111	139	143	147	151	157	17	0.5%
Middle East	353	743	879	992	1 117	1 226	483	2.1%
Eurasia	743	880	919	945	981	1 016	136	0.6%
Russia	620	699	711	721	739	755	56	0.3%
Asia Pacific	3 009	5 699	6 679	7 226	7 684	8 068	2 369	1.5%
China	1 143	3 006	3 439	3 631	3 742	3 797	791	1.0%
India	441	897	1 228	1 466	1 694	1 901	1 003	3.2%
Japan	518	431	414	402	392	384	- 48	-0.5%
Southeast Asia	385	643	806	892	977	1 062	419	2.1%
Bunkers**	273	388	458	506	559	617	230	2.0%
World	**10 035**	**13 760**	**15 182**	**16 011**	**16 806**	**17 584**	**3 824**	**1.0%**

* Compound average annual growth rate. ** Includes international marine and aviation fuels.

Patterns of consumption are different in the Sustainable Development Scenario. The most significant contrast is that access to modern energy becomes universal by 2030, finally closing the gap in the world's provision of energy for all. Since the energy consumption of those gaining access is often very small, this has the effect of bringing down the average per capita consumption of modern energy in Africa and some developing economies in Asia compared with today. With the achievement of universal access, the overall delivery of energy services (e.g. lighting, cooking, heat, mobility) in the Sustainable Development Scenario is higher than the New Policies Scenario, even though the amount of energy consumed by 2040 to deliver these services is some 20% lower.

Figure 2.1 ▷ Modern primary energy demand per capita by scenario



The Sustainable Development Scenario delivers a higher level of energy services in 2040 than the New Policies Scenario, but with nearly 20% less consumption of modern energy

Notes: toe = tonnes of oil equivalent. Modern primary energy demand excludes traditional biomass. The country/regional blocks show only those with access to modern energy.

Given that rates of gross domestic product (GDP) growth are constant across the scenarios, the lower energy consumption in the Sustainable Development Scenario represents a substantial additional improvement in energy intensity. In all scenarios, energy intensity improves as the balance of economic activity switches towards less energy-intensive activities, such as services. But there is a large variation across scenarios in the scope and application of energy efficiency policies. This results in an average improvement of 2.3% per year in global energy intensity in the New Policies Scenario, higher than the average level since 2000. This is still well below the average rate of 3.2% required and achieved in the Sustainable Development Scenario. In absolute terms, Europe achieves the lowest ratio of energy consumption to economic activity by 2040, taking over from Japan.

Changes in global patterns of consumption stimulate changes across the rest of the energy system. The need for new energy infrastructure is concentrated in the growth areas of the energy system. Developing economies in Asia account directly for 30% of the $41 trillion in investment in new energy supply required in the New Policies Scenario, including a large share of investment in low-carbon technologies. Indirectly, they also provide the stimulus for a further $4 trillion of investment in the resources and supply routes that feed their increasing need for imported energy. This shift in the balance of consumption and trade has major implications for institutions dealing with energy, not least the International Energy Agency (Spotlight).

S P O T L I G H T

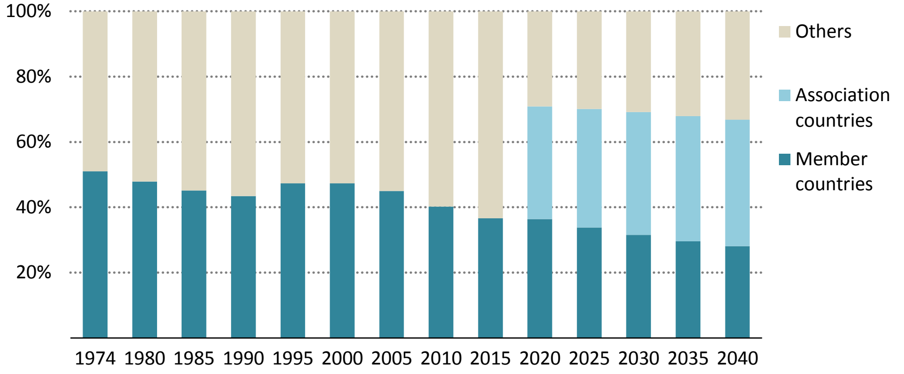
How can the IEA keep up with global energy demand(s)?

The long-term trends in global energy demand point to a strategic challenge for the International Energy Agency (IEA). The energy world is simply very different from the way it was back in the 1970s, when the IEA was created to promote collaboration on oil security, technologies, data and sound policies. Member countries of the IEA, at that time, accounted for more than half of global energy demand and their actions held considerable sway over the way that energy markets functioned and developed.

Since its inception, the IEA has always had a global perspective; this is an analytical necessity in a highly integrated energy world. However, the hard data shows that its membership has, for some time, accounted for a shrinking share of global consumption, and by 2015 this share had fallen well below 40%. In response, the IEA has stepped up its efforts to adapt. In 2015, ministers from IEA member countries endorsed a wide-ranging modernisation of the Agency, based on three pillars: an "open door" policy for institutional ties with major emerging players in global energy; a broader commitment to energy security, including new challenges in gas markets and in the electricity sector; and a strong leadership role in clean energy, notably for energy efficiency.

Since November 2015, seven countries have joined the IEA as Association countries – Brazil, China, India, Indonesia, Morocco, Singapore and Thailand, allowing the IEA to reflect more accurately the global nature of the energy system. Stronger institutional ties mean working collaboratively on improving energy data and statistics, co-operating closely on energy security and engaging on energy technologies and policies. In addition to the Association countries, Mexico is also in the final stages of joining the IEA as its 30th member. With these new additions, the extended IEA family accounts for some 70% of the world's energy use – higher than when the IEA was created in 1974 and almost double the share in 2015. Based on our projections in the New Policies Scenario, the share of this extended family remains well above 60% through to the end of the projection period in 2040 (Figure 2.2).

Figure 2.2 ▷ Share of IEA member and Association countries in world primary energy demand in the New Policies Scenario



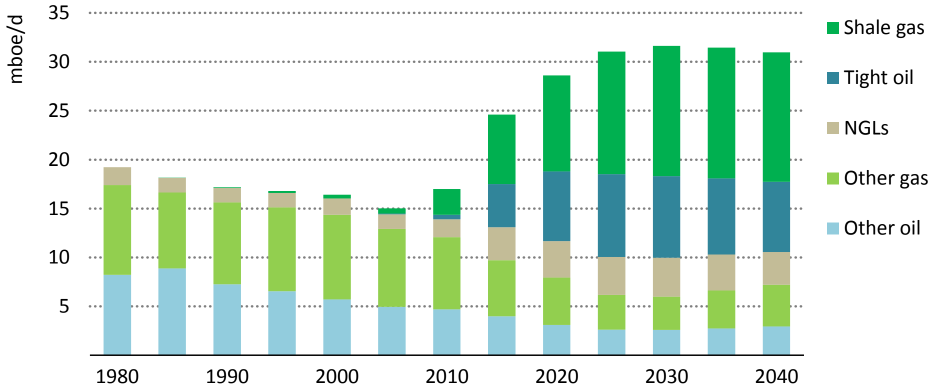
A new strategic orientation for the IEA has brought the share of the extended IEA family in global energy demand to 70%

2.2 Where now for energy in the United States?

Ten years ago, the United States was importing 14 million barrels of oil equivalent per day (mboe/d) of oil and gas and it was widely understood that the future would see only a steady worsening of the net energy trade balance. Domestic production of both oil and gas had been on the slide for more than two decades and investors were busily putting plans and infrastructure in place to receive an apparently inevitable wave of additional imports.

Yet only a couple of years later, the IEA was already signalling a significant change. A key conclusion of the *WEO-2009* was that a "silent revolution" was underway in the United States that would have "far-reaching impacts" on energy markets. The surge of shale gas and tight oil production has accelerated dramatically since then (Figure 2.3). There are many examples of a country switching from being a net energy exporter to a net importer: it is very rare to see the opposite, especially when the country in question is one of the world's largest importers of oil. Yet this is precisely what is happening as a result of the US shale revolution – both for oil and for natural gas.

Figure 2.3 ▷ US oil and gas production in the New Policies Scenario



Shale gas and tight oil, allied with greater efficiency on the demand side, are producing an extraordinary turnaround in the US position in global energy

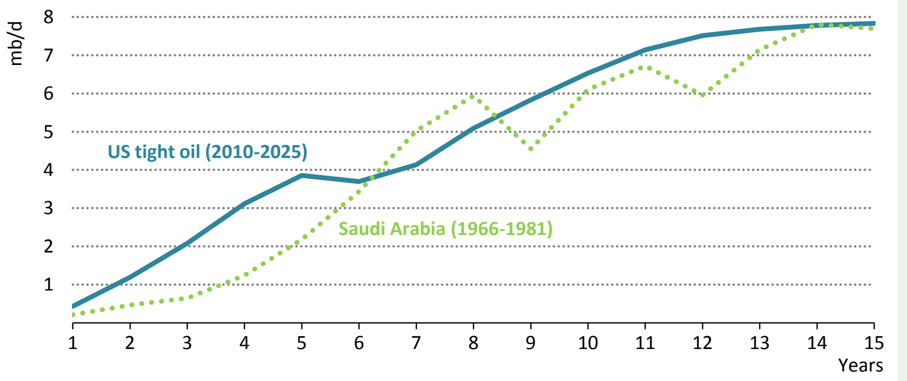
The rise in US production is not yet done. Growth picked up again in 2017, even at much lower prices, and our projections in this *Outlook* have been revised upwards compared with the *WEO-2016*, mainly on the back of higher resource estimates, but also factoring in other developments such as the consolidation of acreage, a strategic shift by some major companies in favour of investment in shorter cycle projects, and continued cost reductions and efficiency gains. The result is that combined US oil and gas production reaches a plateau well above 31 mboe/d in the 2030s, from around 24 mboe/d today. This is 50% more oil and gas than any other country has ever managed to produce in a single year. The speed at which US oil and gas production has increased – and is projected to grow in the next few years – matches or exceeds the biggest rises in energy history (Box 2.1).

This energy renaissance in the United States has had major implications for the domestic economy. Since 2010, almost $1 000 billion in capital investment has been committed to the US upstream and an additional $200 billion to pipelines and other midstream facilities. Given that the United States has a strong oil field service industry and a substantial proportion of rigs, pipes, pressure pumps and other equipment are manufactured at home, this investment wave has had strong spillover effects for economic growth. Similarly, the availability of cost efficient feedstock has attracted major investments in petrochemicals and other energy-intensive industries. Some 13 million tonnes of new ethane crackers are set to come online in the next few years. With limited demand growth on the domestic market and a cost advantage over naphtha crackers elsewhere, the United States emerges in our *Outlook* as a major exporter of ethylene products.

Box 2.1 ▷ The US shale revolution in context

The rise in US production of tight oil and shale gas is set to match or exceed the most dramatic sustained rises in output ever seen by individual countries. On the oil side, the rise in output projected to 2025 in the New Policies Scenario would be about as fast as the rise in output from Saudi Arabia between 1966 and 1981 (Figure 2.4); this was the period in which the supergiant Ghawar field – the largest oil field ever discovered – ramped up to its maximum reported production of 5.7 mb/d. For natural gas, as examined in Chapter 9, the rise in US shale gas projected from 2008 to 2023 would exceed the growth in gas output in the Soviet Union between 1974 and 1989: this was the period when the gigantic gas finds of Western Siberia, Urengoy and Yamburg, were developed for the domestic market and for export to Europe.

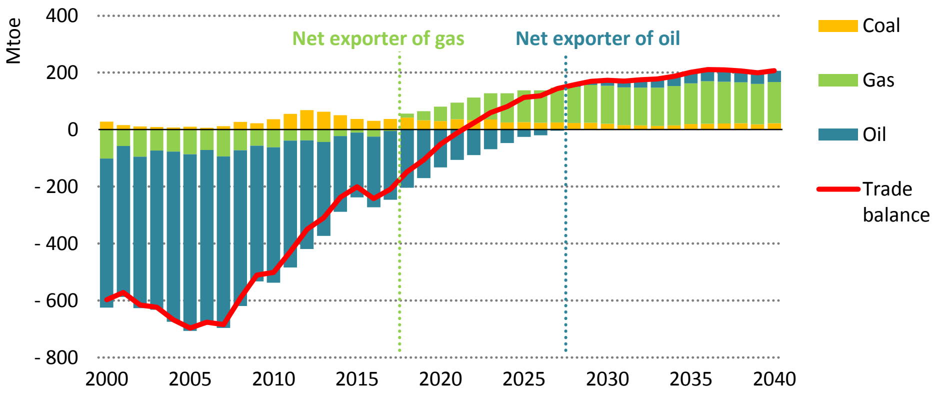
Figure 2.4 ▷ Rise in US tight oil to 2025 in the New Policies Scenario



Projected US tight oil growth is set to rival growth in Saudi Arabia in the 1960s-1970s, the greatest increase seen over a sustained period in the industry's history

The United States is also now within touching distance of becoming a net exporter of fossil fuels (Figure 2.5). This achievement (which does not mean a halt to all imports, since the United States will still be importing substantial volumes of crude oil and gas, while exporting slightly more) is typically ascribed primarily to the supply side. However, the demand-side story is also hugely significant, particularly for oil. US oil consumption has grown slightly since 2015, largely in response to the fall in prices, but our projections are for continued structural decline over the period to 2040. The fall – by some 4.3 million barrels per day (mb/d) to 2040 compared with today – is largely due to the impact of continued improvements in fuel-economy standards for passenger vehicles and trucks, although switching to natural gas, biofuels and electric vehicles all play a role as well. If, however, US fuel-economy standards were to remain at today's levels, all else being equal, the United States would remain a large net oil importer in 2040.

Figure 2.5 ▷ US net fossil-fuel trade by fuel in the New Policies Scenario



The United States is switching already to become a net gas exporter, and is projected to become a net oil exporter in the late 2020s

The implications of the shale revolution for international markets and energy security have been profound. Tight oil has weathered the turbulent period of lower oil prices since 2014 with remarkable fortitude, its resilience confounding expectations in some quarters that a spell of low prices might nip the revolution in the bud. Its shorter investment cycle, compared with conventional projects, has also transformed oil market dynamics as tight oil producers react quickly to any sign of higher prices caused by Organization of Petroleum Exporting Countries' (OPEC) return to active market management (see section 2.8). This effect does not last indefinitely in our projections: even with continued technology and efficiency gains, the move to second- and third-tier acreage once the most productive areas are depleted pushes up costs. This means a plateau for US output in the 2020s (at around 17 mb/d) before production starts to fall back towards the end of the projection period.

In the natural gas market, production remains higher for longer (the shale gas resource estimates are higher in oil equivalent terms than those of tight oil) and the surge in US production and exports has a similarly disruptive effect on the established order, with the United States exporting not only gas but also a mind-set about how gas markets should operate. As regasification facilities are re-tooled as liquefaction sites, up to 140 bcm of annual US liquefied natural gas (LNG) exports by the late 2020s represent a major challenge to incumbent suppliers and traditional business models, helping to change the way that gas is priced and marketed worldwide, and chipping away at the rigidities that have characterised gas trade arrangements in the past. In our projections, a second wave of investment in US liquefaction facilities in the 2020s makes the United States the largest LNG exporter in the world.

The notion of independence in energy is important, but in practice, no country is an island in a deeply interconnected energy world. Even with the extraordinary move to a net export position, the health of the US energy economy remains intricately linked with those of its neighbours in North America and with choices made by countries further afield. The configuration of the US refining system, for example, means that the United States is projected to remain a larger importer of heavier crudes as well as a major exporter of light crude and refined products. The risk of a physical interruption to US supply may recede somewhat with the reduced need for imports, but the threat of disruption from hurricanes and other natural disasters remains, and no country is immune from the effects of worldwide fluctuations in markets and other impacts of a changing global energy system.

2.3 What does China's "energy revolution" mean for its energy outlook, and for the world?

The largest energy consumer in the world since 2009, China's meteoric pace of growth and an unprecedented build-out of national infrastructure has determined the direction of many global energy trends over the last twenty years. Our special focus on China in this *Outlook* highlights that the country will continue to shape global trends over the next two decades to 2040, but the way in which it does so will change as the country shifts into a much less energy-intensive phase in its economic development, guided by a new set of policy priorities. China's energy future will not be a continuation of its energy past.

China's economic transition provides a vitally important backdrop to our analysis. The current economic model is highly oriented towards heavy industrial production, infrastructure development and the export of manufactured goods. In our *Outlook*, GDP growth slows to below 5% from the late 2020s onward – not least because the growth in the population levels off at around 1.4 billion people. As income per capita approaches the level of developed economies by the end of the projection period, an ageing population and the emergence of a large middle class brings a shift in preferences and consumption patterns that has huge implications for the structure of demand in the economy as well as demand for energy. The epitome of the Chinese energy consumer of the past has been a large industrial facility, producing the steel or cement that has built the country's cities, roads and factories. The archetype of the future is more likely to be an urban household, whose rising income is spent on a range of services as well as consumer goods, and whose concerns certainly include the quality of the local air and water.

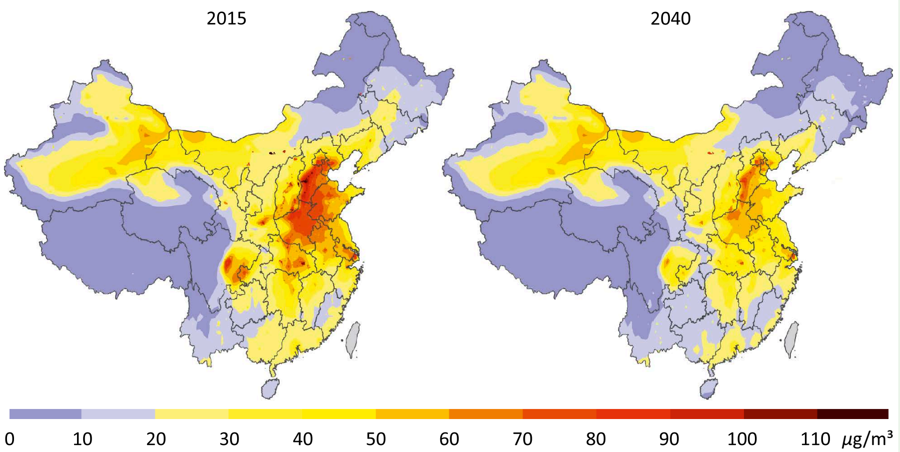
China's rise has been fuelled by coal, which today accounts for almost two-thirds of China's primary energy demand – one of the highest such shares in the world. Coal meets most of the country's huge industrial demand for energy and also provides the backbone of China's immense power system, which has needed to accommodate a quadrupling in electricity demand since 2000. The coal plants – and environmental legacy – of China's period of breakneck growth will be with the country for some time, not least because more than half of China's massive coal-fired fleet is less than ten years old.

Box 2.2 ▷ Air quality in China

Poor air quality is a major public health issue in China, in particular in the main industrialised areas of the country, and the causes and solutions are to be found in the energy sector. The drive to reduce pollutant emissions and improve the quality of life in China's growing cities is a major driving force behind energy policy. Increasingly stringent standards are being introduced for the main sources of emissions, and significant progress has been made: pollutant emissions from coal combustion peaked around 2010 and total emissions of fine particulate matter ($PM_{2.5}$), the most damaging pollutant for human health, declined by about 20% over the past decade, largely because of new industry sector regulation and a shift away from biomass as a residential fuel.

Nonetheless, the road ahead is set to be a long one. Around 1 million premature deaths are currently attributable each year to outdoor air pollution, largely due to industrial, power and transport emissions, and almost as many to household air pollution, largely due to the continued use of coal and biomass for heating and cooking. In the New Policies Scenario, emissions of all the major pollutants fall substantially to 2040 (Figure 2.6 and Chapter 13). Despite these reductions, an ageing and increasingly urban population is more vulnerable to the effects of air pollution. More than 1.4 million premature deaths are still associated with poor outdoor air quality in China in 2040, although the health impacts of household air pollution are reduced substantially with the move to cleaner fuels in households.

Figure 2.6 ▷ Concentration of $PM_{2.5}$ in China in the New Policies Scenario



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

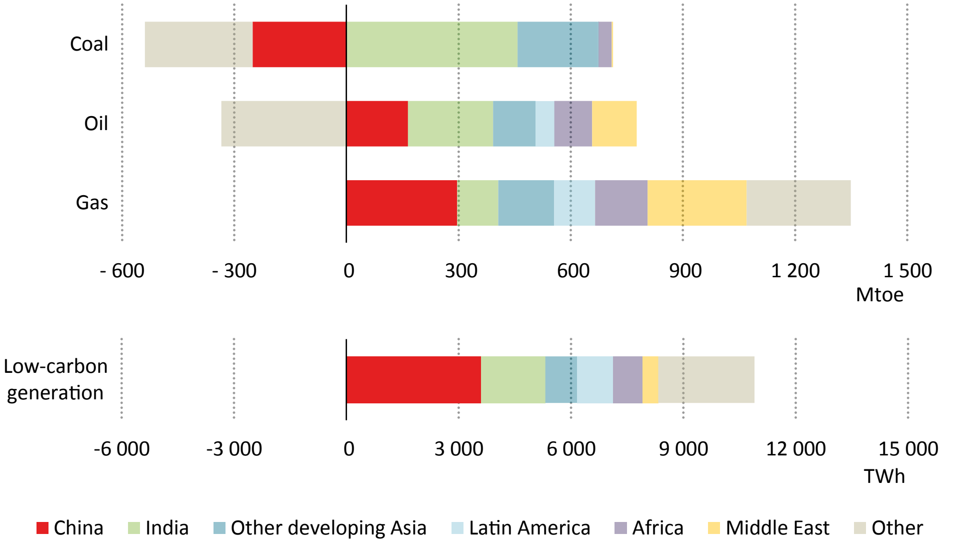
Air quality significantly improves in China in the New Policies Scenario, but the number of premature deaths attributable to poor air quality remains high

Source: International Institute for Applied Systems Analysis.

The parallel rebalancing of China's energy system away from coal and away from the current concentration on heavy industrial consumption are two of the major themes of this *Outlook*. This process is well underway: in all probability, China's coal consumption peaked in 2013 as demand from the iron and steel sector started to fall; a peak in energy-related carbon-dioxide (CO_2) emissions from the industrial sector could well have already been reached in 2014. Attention and investment are now switching decisively to cleaner energy: China, by a distance, is the largest global investor in renewables, accounting for 40% of global installations of renewable power capacity in 2016, and holds a commanding position in global solar equipment manufacture and deployment.

Energy demand growth has already slowed markedly from an average of 8% per year from 2000 to 2012, to less than 2% per year since 2012, and slows further to an average of 1% per year to 2040 in the New Policies Scenario. The impact of a suite of energy efficiency initiatives on future growth is reinforced by the reduced energy needs of China's new economic model: the share of services in GDP rises at the expense of industry, and lighter industrial sectors take over from more energy-intensive ones. Its future economy also requires different types of energy from that of the past: more electricity, increasingly from low-carbon sources, and more natural gas (Figure 2.7).

Figure 2.7 ▷ Contribution of China to change in fossil-fuel demand and low-carbon generation in the New Policies Scenario, 2016-2040



Growth in China's energy consumption to 2040 comes mainly from natural gas and low-carbon technologies, a sharp break with past trends

Note: Mtoe = million tonnes of oil equivalent; TWh = terawatt-hours.

These structural changes are being reinforced and pushed by China's energy policy. The long-term energy development agenda is defined by the call for an "energy revolution", made by China's president in 2014, to counter the huge demand pressures and serious environmental problems that the country faces. Policies and targets – set out in the 13th Five-Year Plan and other strategy documents – are playing an important role in steering the energy transition, but they co-exist with the pledge to "let markets play a decisive role" (which underpins the anticipated liberalisation of gas and electricity markets), and the drive to loosen the dominance of China's state-owned enterprises in the energy economy.

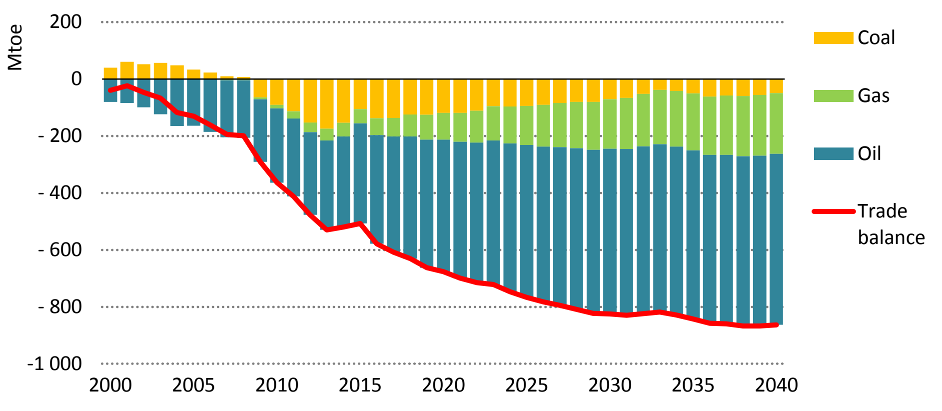
The results of this new direction are very visible in our projections in the New Policies Scenario. Coal consumption never exceeds its 2013 peak and demand ends up almost 15% lower by 2040. Oil demand continues to increase – making China the world's largest oil consumer when it overtakes the United States around 2030 – but then flattens out as the rise in electric vehicles cuts into road transport oil demand. Electricity becomes the leading source of final energy consumption in China, overtaking coal by the late 2020s, and oil shortly thereafter. Natural gas demand grows by 400 billion cubic metres (bcm), a full one-quarter of the global increase in gas use, as industry switches to a cleaner and more convenient fuel, gas use grows in the power sector and in buildings, and distribution networks extend to residential consumers in southeast China.

The most dramatic growth comes from low-carbon sources, led by renewables: by 2040 they constitute nearly one-quarter of the energy mix. In the power sector, continuing market reforms and network development are critical to accelerate deployment of renewables, not least to relieve the constraints that have curtailed some 15-17% of output from China's solar and wind capacity. In our projections, renewables and nuclear account for almost all of the increase in capacity as investment in new coal-fired plants collapses; by 2040, low-carbon sources of power account for 60% of installed capacity and around half of generation. This underpins a large fall in emissions of the main air pollutants and in the concentration of fine particulate matter in the air: by 2040, almost half of the population lives in areas that meet the national air quality standard, up from 36% today. Energy-related CO_2 emissions in China as a whole peak at 9.2 gigatonnes (Gt) shortly before 2030; by the end of the projection period, all sectors of the energy economy have seen peaks in CO_2 emissions with the exception of transport.

The pathway outlined in the New Policies Scenario is by no means an easy one for China: the shift towards lighter industry and services entails a dislocation for heavy industrial sectors. Employment in the coal sector falls sharply, from 4 million people today to less than 1 million in 2040, as current overcapacity is reduced and less efficient mines are shut. However, a detailed analysis of the interactions between the macro-economy and the energy sector in Chapter 15 suggests that gains from any attempt to prolong the lifetime of the old coal and industry-based economic model would be short-term and come at a high cost. Delaying the economic transition and slowing the transition from heavy manufacturing to services would not bring any long-term dividend in terms of GDP, but it would mean lower average wages across the economy as a whole. It would also keep China on a more energy- and CO_2-intensive pathway.

The outcomes in the New Policies Scenario offer some good reasons for China to push ahead even more quickly with its energy transition. As highlighted in Box 2.2, air quality continues to be a major public health hazard. And import dependence is set to grow, with implications for China's energy security. In 2016, China's net oil and gas import requirement was accelerating towards the level seen in the United States before the start of the shale revolution (see section 2.2). But the chances that a similar surge in supply might now transform China's energy trade balance seem, for the moment, quite remote. Existing conventional production areas are already mature and the remaining resources relatively costly; and while China has large estimated tight oil and shale gas resources, they are proving difficult to develop at scale. Gas output does increase in our projections (albeit not nearly as fast as demand), but oil production declines steadily, pushing China's oil imports up to 13 mb/d – a level seen only by the United States in its peak import years around 2005 (Figure 2.8). By 2040, three out of every ten barrels of oil traded internationally are heading for a Chinese import terminal.

Figure 2.8 ▷ China net fossil-fuel trade by fuel in the New Policies Scenario



China's fossil-fuel import requirements continue to rise to 2040, raising concerns over potential energy security vulnerabilities, especially for oil

The idea of a faster transition is already incorporated into some of China's long-term policy documents, including the Energy Production and Consumption Revolution Strategy that was released in 2017. This would have profound implications for China and for global energy developments. For instance, an ambitious but plausible suite of additional policies to limit growth in car ownership and promote faster electrification of mobility in China's cities could cut the country's oil demand (and imports) by 2.5 mb/d in 2040, an amount sufficient, all else being equal, for global oil consumption in the New Policies Scenario to plateau around 2030.

In the New Policies Scenario, China is responsible for a large share of global investment in a range of low-carbon technologies, including electric vehicles, batteries, carbon capture and storage, nuclear power, and solar and wind power. An accelerated transition, of the sort outlined in the Sustainable Development Scenario, would serve to cement China's position in these domains, with additional environmental benefits reinforced by industrial and economic advantages. For other countries, the cost reductions engendered by China would give momentum to the transition elsewhere; they would also provide a powerful incentive to develop competing clean technologies that can vie for market share.

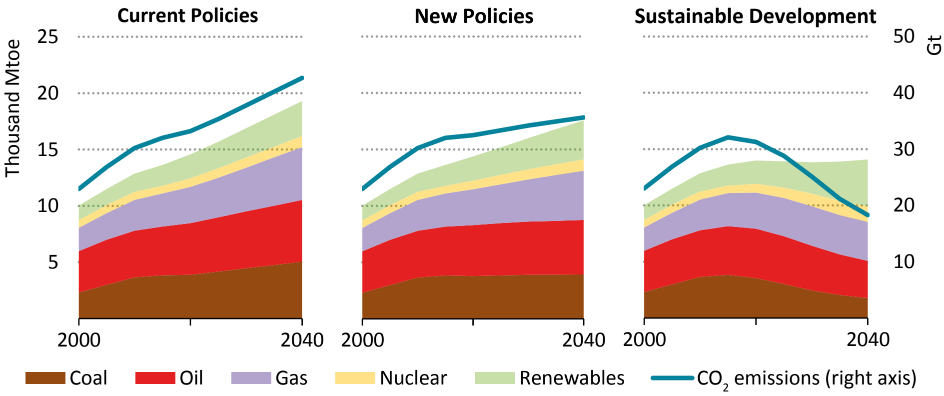
2.4 What is the next move for energy-related CO_2 emissions?

A third straight year of flattening in global energy-related CO_2 emissions, as seen in 2016, starts to look like a trend break, rather than a hiatus. There are plenty of reasons for cautious optimism that the apparently inexorable upward march in emissions is slowing, at least. But there are also reasons for caution. A flattening in the emissions trend is not sufficient to address the challenge of climate change: as the Paris Agreement makes clear, the aim is to achieve "global peaking of greenhouse-gas emissions as soon as possible" followed by "rapid reductions thereafter". Even more importantly, while some low-carbon technologies are making real gains, not least in terms of their cost-competitiveness, some of the other elements that produced the recent slowdown in emissions might not be easy to repeat, notably the coal-to-gas switching seen in the United States. Given that the world, in the New Policies Scenario, needs to add the equivalent of more than today's China to its current energy demand by 2040 (see section 2.1), it should not be taken for granted that energy-related CO_2 emissions will move downwards from now on.

In practice, only one of our three main scenarios sees a decline in global energy-related CO_2 emissions over the period to 2040: this is the Sustainable Development Scenario (which works backwards from what is necessary to achieve global climate goals) (Figure 2.9). Neither the realisation of current policies, nor the additional consideration of "new policies", is sufficient to achieve such a peak, although the New Policies Scenario does see a considerable slowdown in growth compared with the period 2000-2014. An examination of trends in the different parts of the global energy economy helps to explain why emissions keep rising in this scenario.

Power generation has been at the vanguard of the energy transition and this remains the case in the New Policies Scenario. Deployment of many low-carbon technologies continues apace, led by wind and solar photovoltaic (PV). Renewables meet two-thirds of the growth in electricity demand between now and 2040 and capture two-thirds of global investment in power plants to 2040, in large part because they become cost-competitive in many cases with new thermal power plants, aided by rising carbon prices in some regions. The share of wind and solar in the global generation mix grows from today's 5% to almost 20% over the same period, pushing the share of renewables as a whole up to 40%.

Figure 2.9 ▷ World primary energy demand by fuel and energy-related CO_2 emissions by scenario



The flattening of emissions in 2014-2016 is a pause in a slower upward journey in the New Policies Scenario, but a turning point in the Sustainable Development Scenario

A major finding in this *Outlook* is that the age of rapid growth in coal-fired power is almost at an end. Since the beginning of the 21st century, global coal-fired capacity grew by nearly 900 gigawatts (GW). Yet, in the New Policies Scenario, net coal-fired additions for the entire period to 2040 total only 400 GW, and almost 40% of these take place in the coming few years with plants that are already under construction entering into service. As a result, the share of coal in global generation declines steadily, from 37% today to 26% in 2040, and it is overtaken as the largest source of generation by renewables in the late 2020s. Coal use in the New Policies Scenario is essentially flat (Table 2.2). Considerable improvements in power plant efficiency also constrain consumption and emissions, notably for gas as more high-efficiency combined-cycle designs enter the market.

This shift in the power mix is impressive, but not enough to put the sector's CO_2 emissions into reverse in the New Policies Scenario against a backdrop of continued strong growth in global electricity demand. Electricity consumption grows faster than all other major final energy sources as more end-uses are electrified, rising industrial activity pushes up the use of electric motor systems and rising incomes increase demand for appliances and energy services (cooling in particular). Power-related CO_2 emissions are nonetheless limited to a 5% increase between now and 2040, while electricity demand grows by 60% and global GDP by 125%.

Among the end-use sectors, energy use in buildings consumes more electricity than any other end-use, meaning that decarbonising electricity supply offers a valuable indirect way to reduce emissions. The main direct avenues are higher standards for appliances, lighting, air conditioners and so on, and improvements in building insulation to reduce heating and cooling needs. The example of India's light-emitting diode (LED) bulb replacement programme shows what can be done: more than 250 million LED bulbs have been distributed so far (with a target of replacing 770 million bulbs by 2019) with bulk procurement driving down costs and average household electricity bills being reduced by 15% where the bulbs have been installed. We estimate that the savings that will be achieved by sales of LEDs in India in 2016 are comparable to the total electricity generated from solar PV in India in the same year. If this type of effort is mirrored elsewhere and extended to other appliances, and then to even more challenging areas such as building designs and retrofits, then CO_2 emissions from the buildings sector can be mitigated effectively. As things stand in the New Policies Scenario, these opportunities are pursued with sufficient vigour to keep buildings sector emissions flat to 2040.

Table 2.2 ▷ World primary energy demand by fuel and scenario (Mtoe)

			New Policies		Current Policies		Sustainable Development	
	2000	2016	2025	2040	2025	2040	2025	2040
Coal	2 311	3 755	3 842	3 929	4 165	5 045	3 023	1 777
Oil	3 670	4 388	4 633	4 830	4 815	5 477	4 247	3 306
Gas	2 071	3 007	3 436	4 356	3 514	4 682	3 397	3 458
Nuclear	676	681	839	1 002	839	997	920	1 393
Hydro	225	350	413	533	409	513	429	596
Bioenergy*	1 023	1 354	1 530	1 801	1 507	1 728	1 272	1 558
Other renewables	60	225	490	1 133	441	856	633	1 996
Total	**10 035**	**13 760**	**15 182**	**17 584**	**15 690**	**19 299**	**13 921**	**14 084**
Fossil-fuel share	*80%*	*81%*	*78%*	*75%*	*80%*	*79%*	*77%*	*61%*
CO_2 emissions (Gt)	**23.0**	**32.1**	**33.4**	**35.7**	**35.4**	**42.7**	**28.8**	**18.3**

* Includes the traditional use of solid biomass and modern use of bioenergy.

However, it is a tall order for the other main end-use sectors – transport and industry – to deliver similar performance, as they are much more difficult to decarbonise. In the transport sector, oil consumption continues to grow in the New Policies Scenario (see section 2.8) and, as a result, CO_2 emissions from oil use in transport almost catch up with emissions from coal-fired power plants, which are flat. In industry, despite existing policies in many countries, which typically take the form of carbon prices or efficiency standards, the rise in industrial production and the lack of easy alternatives to fossil fuels in parts of this sector means that industry-related CO_2 emissions continue to grow by more than 20% over the period to 2040.

The net impact of all of these sectoral trends is that energy-related CO_2 emissions in 2040, at 35.7 Gt, are around 600 million tonnes (Mt) lower than the 36.3 Gt projected in last year's *Outlook*. At country level, this reduction is largely due to further policy pushes in India and China, which continue to increase their ambition for renewables and electric vehicles deployment. In the case of India, the reduction in projected 2040 emissions (410 Mt) stems mainly from increased low-carbon deployment in the power sector. In China, emissions of all major air pollutants fall and energy-related CO_2 emissions plateau at 9.2 Gt before 2030 and then start to decline, supported by peaks in industry (2014), buildings (2019) and power generation (2030): only transport emissions do not peak. In the European Union, CO_2 emissions fall by 2% per year to 2040, with progress reinforced by the Clean Energy for All package released in late 2016.

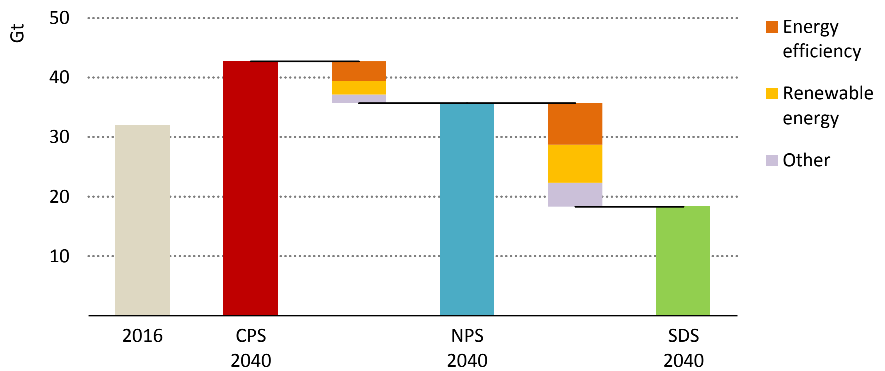
While encouraging in some aspects, the emissions trajectory in the New Policies Scenario is clearly out of step with the requirement of the Paris Agreement, underlining the scale of the challenge – in an expanding energy system with growing energy needs – to turn these trends around. The share of fossil fuels in primary energy demand falls by 2040 to 75% in the New Policies Scenario, from 81% today (oil falling from 32% to 27% over this period, coal retreating from 27% to 22%, while gas climbs from 22% to 25%). A much sharper trend break is required in the Sustainable Development Scenario, in which total fossil-fuel use drops to 61% of primary demand by 2040 (gas remaining with a 25% share of a smaller pie, while oil drops to 23% and coal plummets to 13%). The hallmark of the accelerated transition in the Sustainable Development Scenario is a much greater focus on energy efficiency and low-carbon technologies: well-designed policies can capture synergies between them (Box 2.3).

Box 2.3 ▷ Joining forces: how renewables and energy efficiency can be more than the sum of their parts

Renewables and energy efficiency account for the overwhelming share of the reductions in CO_2 emissions between our three scenarios, including more than three-quarters of the incremental abatement between the New Policies Scenario and the Sustainable Development Scenario (Figure 2.10). These two pillars of a low-carbon energy future are typically viewed and pursued separately, but in places the technology and business boundaries between the two are starting to blur (see Chapter 7). Renewable technologies such as solar PV and solar water heating are becoming part of the toolboxes of energy efficiency service providers. Renewable businesses are increasingly incorporating efficiency into their own business models, for example, when low energy appliances increase the utility of off-grid solar in the developing world (see section 2.6). The more these two areas overlap, the greater the need for integrated policy approaches.

An example of how well-designed policies can smooth the interactions between efficiency and renewables comes from the residential sector. The capacity to modulate demand from households becomes increasingly important in our projections as a cost-effective way to balance power systems that have a high share of variable renewables (a source of flexibility known as demand-side response). Consumers might be remunerated if, for example, the times at which their air conditioning or electric water heaters are operating can be co-ordinated with the wider demands of the system, reducing or avoiding consumption at a time when wind and solar output is low, and vice versa. However, these types of appliances and equipment ("flexible load") are also disproportionately the focus for end-use efficiency policies, while the coverage of equipment that needs to draw power exactly at the time when consumers demand the service ("inflexible load", such as ovens, light bulbs, televisions and computers) is lower. In 2016, only around one-quarter of inflexible residential load was covered by mandatory efficiency policies, compared with well over half of flexible load. Ensuring that efficiency measures reduce demand from all sources of load to a similar extent would help to mitigate any tension between efficiency goals and the potential for demand-side response. Similarly, co-ordinating policy to target high-carbon power systems with efficiency measures and to focus on demand-side response in regions with a high share of variable renewables would bring system-wide benefits.

Figure 2.10 ▷ Contribution of energy efficiency and renewables to global reductions in energy-related CO_2 emissions by scenario



The wide difference in emissions levels across our scenarios in 2040 is explained almost entirely by variations in policies for efficiency and renewables

Note: CPS = Current Policies Scenario; NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

2.5 How much do energy policies matter?

There are different schools of thought on what is driving the transition towards a more sustainable energy system. For some, it is the energy policies adopted by governments. For others, technology innovation and private sector initiative are taking the lead. A third motive force is the bottom-up pressure exerted by society and reflected in community or municipal-level commitments to clean energy. All of these have plausible claims and, in many instances, they are strongly interdependent. However, some recent commentary has suggested that the transition has now reached a tipping point, with low-carbon technologies sufficiently mature and competitive for their path to higher market share to run independently of national policy. It is this claim that we wish to examine.

Some areas of the low-carbon transition have indeed gained powerful momentum. There are technologies that are loosening or have already shed their dependence on public subsidies; in parts of the world with high-quality resources, solar PV and wind can be among the cheapest options for new generation, and this becomes increasingly common in our projections. Where low-cost financing is available and the carbon price and/or fossil-fuel prices are high enough, the cost of new renewables could even start to undercut the operating costs of existing thermal power plants (see Chapter 6). Strong impetus is also coming from private companies, city authorities and other sub-national initiatives (see Spotlight in Chapter 3).

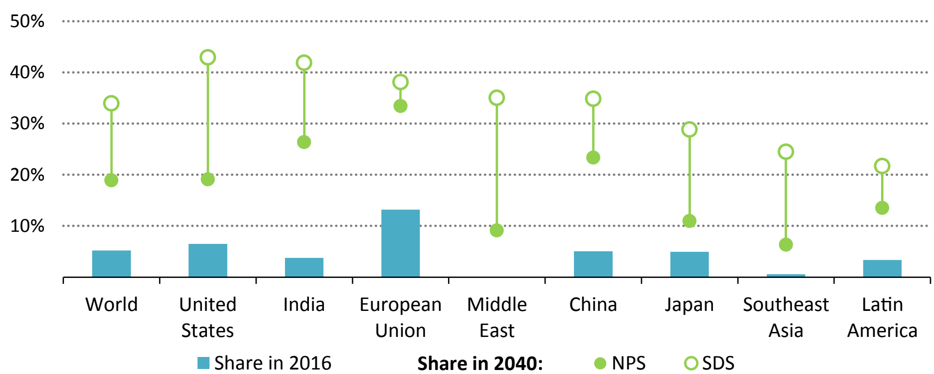
So there is momentum, but that is far from meaning that the world's environmental objectives will be met without any further policy support or that the road ahead is clear of all obstacles. The projected trajectory for future emissions in the New Policies Scenario has edged downwards over time, but the gap with the emissions reductions required in the Sustainable Development Scenario remains huge in this year's *Outlook*. Technology advances (often themselves a product of government research and development programmes) and bottom-up initiatives can bridge a part of this gap; straight economics will help as renewable options become increasingly cost-competitive; but concerted and well-designed policy support will be essential to close this gap completely.

The power sector is on the frontline of the low-carbon transition, but also provides a good illustration of the reasons why well-designed energy policies remain vital. Very few investments in this sector are purely market-driven, i.e. responding to and relying on prices set in competitive wholesale markets. Well over 90% of global power generation investment in 2016 was made by companies operating either under a regime with fully regulated revenues or with some sort of regulatory or contractual mechanism to manage the revenue risk associated with fluctuating wholesale market pricing (IEA, 2017a). Financial incentives still matter too: in the case of solar power, for example, which made up nearly half of all global capacity additions in 2016, nearly all its growth relied on some form of government support. We estimate that subsidies for renewables in power generation amounted to $140 billion in 2016.

The relative importance of subsidies is set to decline as more and more renewable deployment becomes fully competitive, especially as governments move towards auctions or competitive tenders as a cost-effective way to promote renewables deployment, rather than fixed feed-in tariffs (over 70 countries have now held auctions). But cost reductions alone are not sufficient to secure an efficient decarbonisation of electricity supply. There are major issues of market design that need to be addressed by policy-makers to ensure that generators have ways to recover their costs, and that the power system is able to operate with the necessary degree of flexibility to integrate high shares of variable wind and solar power.

The integration issues for wind and solar are manageable, but, if left unaddressed, they could slow and ultimately halt deployment. Based on the experience of countries that have led the way with wind and solar investment, our judgement is that some significant integration challenges can start to appear when the share of variable renewables in total generation reaches 15%. At or above these levels, it is vital the power system can respond quickly and efficiently to uncertainty and variability in the supply-demand balance. A strong grid and dispatchable power plants are the main current sources of flexibility, but demand-side options and new storage technologies are also set to grow in importance in our projections. In the New Policies Scenario, most parts of the world approach or exceed a 15% threshold by 2040: all of them do in the Sustainable Development Scenario (Figure 2.11). Even at much lower levels of deployment, curtailment of wind generation, for example, is already a major policy issue in China (the subject of detailed analysis in Chapter 13); some 17% of available generation there in 2016 could not be used because of network and dispatching constraints.

Figure 2.11 ▷ Share of variable renewables in power generation in selected regions by scenario



A rising share of wind and solar in total generation requires a range of policy responses to enhance the flexibility of the power system

Note: NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

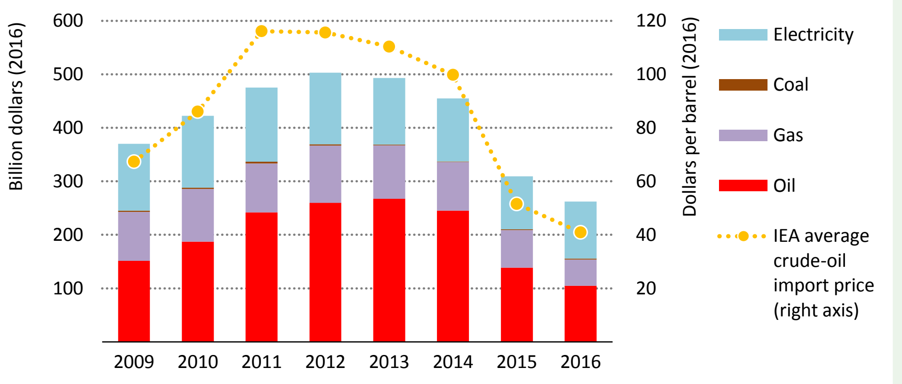
Beyond renewables, there are many other power generation technologies where future prospects are closely linked to government policy. Nuclear energy is a clear case in point, and our projections in the *WEO-2017* reflect both the confirmed intent to scale up the use of nuclear power in China and India, as well as the plans to reduce reliance on nuclear energy in France and Korea. The outlook for other major parts of the global energy economy is similarly dependent on what policy-makers choose to do (or not to do). For example, the heavy freight sector is a major area for growth in oil demand and emissions, where currently only a handful of countries have fuel efficiency standards in place – Canada, China, Japan and the United States (and, soon, India). It is difficult to imagine how improvements in energy efficiency can accelerate at the required pace, especially in the buildings sector, without intervention and encouragement from policy.

Part of the solution, in many countries, is the removal of fossil-fuel subsidies to curb wasteful consumption of energy, as well as the finding of appropriate ways to put a price on carbon (Box 2.4). However, the social and political sensitivity of these choices on energy pricing reform provides a reminder of another constant source of pressure on policy-makers, which is the need to keep energy affordable. Balancing these occasionally competing policy imperatives to find the least-cost pathway to a more sustainable energy system, harnessing the power of the market where possible and regulating where essential, is a necessary task, and one where energy policies continue to matter greatly.

Box 2.4 ▷ Fossil-fuel consumption subsidies: power takes the lead

The estimated value of global fossil-fuel consumption subsidies decreased by 18% to $260 billion dollars in 2016, due in part to lower prices for the main fuels but also to continued efforts at reform. For the first time since the *WEO* started tracking these subsidies, the largest share of global subsidies went to electricity (with 41% of the total[2]), edging ahead of oil (40%), with natural gas accounting for almost all of the remainder (Figure 2.12).

Figure 2.12 ▷ Estimated value of global fossil-fuel consumption subsidies



Lower prices and bolder policies mean that the value of global fossil-fuel consumption subsidies declined again in 2016, to $260 billion

2. The calculation of electricity subsidies is based on the electricity generation mix in different countries and excludes non fossil-fuel subsidies.

The dip in subsidies for oil, and the higher share of electricity, reflect some short-term price developments but also reveal a new set of challenges for subsidy removal. Reforms in many countries often focus in the first instance on oil products used for transport: some notable developments in 2016 were in the Middle East, where many countries increased prices for gasoline and diesel, including Bahrain, Kuwait, Oman, Qatar, Saudi Arabia and United Arab Emirates. Although the Middle East remains the region with the largest share of total subsidies (some 30% of the total), the estimated value of these subsidies has declined sharply, from around $120 billion in 2015 to $80 billion one year later.

The battle in this area is far from over; governments could come under pressure to reinstate subsidies for gasoline and diesel when oil prices start to rise. But, for the moment, the spotlight shifts away from the transport sector to other areas that may be even more difficult to reform. A detailed analysis conducted by the *WEO* team on subsidies in the Asia-Pacific Economic Cooperation (APEC) economies showed that the value of subsidies to oil products for transport has fallen by more than half since 2010, mostly due to pricing reforms (IEA, 2017b). As a result, most of the subsidies in this region are now in the residential sector, primarily for electricity but also for natural gas and liquefied petroleum gas (LPG).

There is a legitimate rationale for subsidy policies to meet the basic needs of vulnerable households, but in practice the subsidies to the residential sector are often not targeted, meaning that they disproportionately benefit better-off households. Electricity price reforms are on the agenda in many countries, with Argentina and Indonesia two prominent examples of reform in 2017. Subsidy policies are also a major underlying reason for the poor financial state of some state-owned power utilities, undermining their ability to invest in new energy infrastructure. A failure to tackle electricity pricing threatens an unsustainable burden in the future, given the likelihood of rising fuel costs and the rising share of electricity in final consumption.

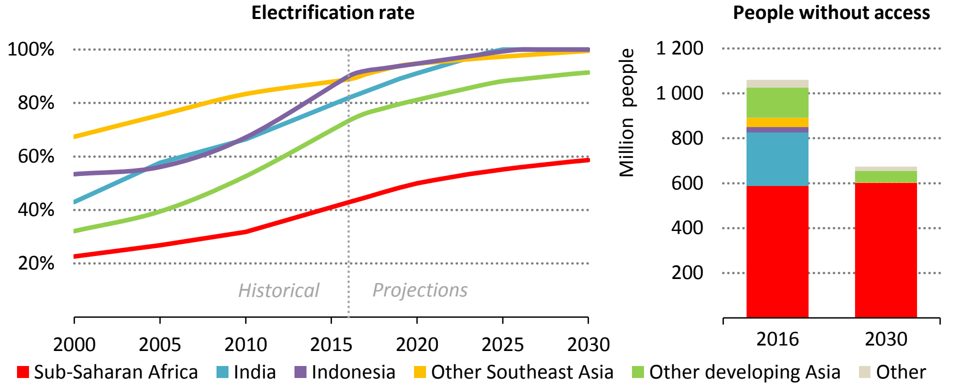
2.6 Are new technologies bringing us closer to universal access to electricity?

The road to universal electricity access has often seemed to be a long and winding one, with a likely time of arrival well after the targeted date of 2030. But two trends are coming together that could shorten the pathway considerably.[3] Technologies are getting cheaper and more accessible, which is helping to bring down the costs and barriers to deployment of decentralised renewable solutions that can play a vital role in bringing electricity to more remote communities. And new entrepreneurial business models are rapidly emerging that

3. A *WEO-2017* Special Report, *Energy Access Outlook*, provides a detailed examination of the prospects of providing modern energy for all, including both electricity and clean cooking facilities; it is available at *www.iea.org/energyaccess.*

pair off-grid systems (typically a small solar PV panel) and energy efficient appliances with innovative financing schemes (typically via mobile phones), enabling millions of people living in rural areas far from an electricity grid to gain affordable access. Allied with political determination to resolve the problem, these new trends could make a huge difference to the 1.1 billion people that remain without access to electricity. The pathway to clean cooking facilities for the 2.8 billion who currently rely on polluting biomass, coal and kerosene is less clear: challenges and solutions to scaling up access to clean cooking are less about technology, and more about logistics (especially for LPG supply to rural areas), affordability, and overcoming social and cultural challenges.

Figure 2.13 ▷ Population without access to electricity in the New Policies Scenario



By 2030, nine-out-of-ten people without access to electricity in the New Policies Scenario are in sub-Saharan Africa

The number of people without access to electricity has fallen from 1.7 billion in 2000 to just below 1.1 billion in 2016. The last four years in particular have seen an acceleration in the number of people gaining access in developing countries: over 100 million people per year since 2012 compared with 62 million per year over the period from 2000 to 2012. Progress in India has been particularly impressive: it has provided access to half a billion people since 2000 (primarily via extension of the grid) and the latest policy push could put the country on track to provide universal electricity access by the early 2020s. There are some positive signs too in sub-Saharan Africa: electrification efforts outpaced population growth for the first time in 2014, leading to a decrease in the number of people without access in the region. Nonetheless, sub-Saharan Africa remains the region with the largest number of people without access in 2030.

For the moment, on-grid remains the primary pathway for providing electricity access, but other options are entering the picture, especially given that almost 85% of those who remain without access in 2016 are concentrated in rural areas, sometimes very remote areas that are difficult or expensive to reach with the main network. The typical solution in these cases has been diesel-fuelled generators, but as the cost of solar PV, wind generation and battery storage comes down, renewable decentralised alternatives have become increasingly viable. Sub-Saharan Africa has become a testing ground for many of the new business models that tap into digital and renewable decentralised solutions. Roughly 10% of those who gained access each year between 2012 and 2015 in this region did so from renewables-based off-grid sources, a major step up from the 0.4% that gained access via this route in 2000-2012. Many of the companies using mobile payments and a pay-as-you-go business model with off-grid systems are in Africa: building on the fact that, while electricity coverage can be patchy, mobile phones are already ubiquitous in many parts of Africa (Box 2.5).

Box 2.5 ▻ Powering up off the grid

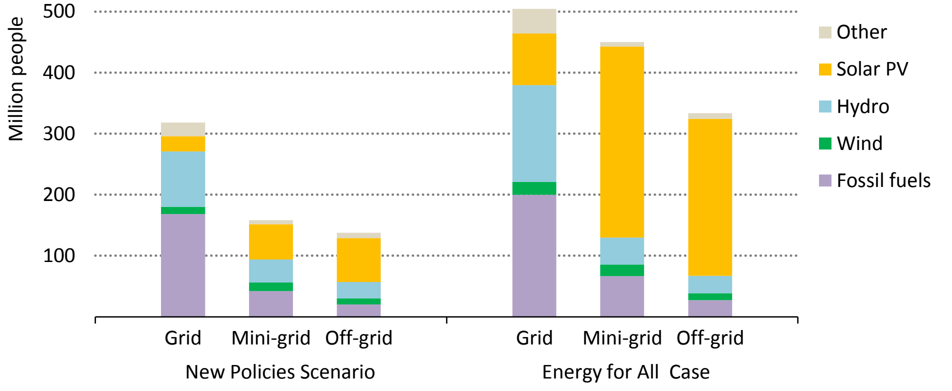
Technology improvements are helping to hasten the provision of decentralised renewable electricity in Africa and South Asia. One of the primary business models that has emerged focuses on areas covered by mobile networks but not electricity grids. In the pay-as-you-go (PAYG) payment model, consumers use their phones to pay a fixed up-front cost for the device – usually a solar panel bundled with battery storage and appliances (which can include lights, radio, mobile phone chargers, and in larger systems a fan, television and refrigerator) – and then pay for its use in instalments. The devices have a subscriber identification module (SIM) card so the business can remotely monitor and collect usage data, and cut off power supply in the event of non-payment, which helps de-risk the investment for suppliers and ensures the sustainability of the business model.

The market is small, but growing fast. Well established in East Africa, the PAYG model has expanded to more than 30 countries, serving an estimated 700 000 households (REN21, 2017). While the majority of those who benefit from off-grid electricity access do not use PAYG models, the growing investment in off-grid solar PV is dominated by companies using the PAYG model. The economics of this off-grid business model rely on what it provides being affordable to poor households, as well as offering an improvement on the energy services they currently have (often kerosene or candle lighting, plus payments to local businesses for charging mobile phones) at a lower cost. The affordability of these systems hinges on three main factors: the PAYG model (these companies are essentially micro-financing households), the bundling of ultra-efficient appliances (to keep the solar panel small), and the falling cost of solar panels and batteries.

In the New Policies Scenario, the number of people without electricity access falls to around 675 million in 2030. Several countries achieve universal access or come close, including Bangladesh, Ethiopia, Ghana, India, Indonesia, Kenya and Viet Nam. For areas with a high population density, notably in or around urban areas, the centralised power grid remains the least-cost option and the primary means for electrification. But significant progress occurs in rural areas too, where roughly 420 million people gain access by 2030: of these 420 million, 30% are projected to do so via the grid, 37% via mini-grids and 33% from off-grid solutions. Of those gaining access from decentralised solutions, around 80% do so from renewable sources, and renewables-based power also plays a significant role in supporting grid-based access in many countries.

In the Sustainable Development Scenario and in the Energy for All Case (based on the New Policies Scenario, but in which universal access to electricity and to clean cooking facilities is achieved by 2030), the additional push for access to electricity takes place almost entirely in rural areas. This means an accelerated deployment of decentralised options but also the expansion of traditional grid electrification (Figure 2.14). Stand-alone solar PV systems provide over three-quarters of the additional off-grid access. In terms of investment, the Energy for All Case would require $56 billion per year on average between now and 2030 (a cumulative total of almost $800 billion), more than twice the level mobilised in the New Policies Scenario and equal to 3.4% of total energy supply investment over this timeframe. Over 90% of the access-related investment is for electricity, and two-thirds of this goes towards decentralised power systems. More than 60% of the investment for electrification is required in sub-Saharan Africa, given that the electrification problem is most acute in this region.

Figure 2.14 ▷ Cumulative population gaining access to electricity in the New Policies Scenario and the Energy for All Case, 2017-2030



Decentralised options – off-grid and mini-grid – are crucial to achieve full electricity access by 2030, especially for remote rural communities, but all fuels and technologies play a part

Note: Other includes nuclear, bioenergy, geothermal and concentrating solar power.

New technology and business models can play a crucial role in meeting basic energy needs for households, by providing decentralised systems to areas that are too expensive to electrify by the grid in the short or medium term. However, the decentralised systems that are being rolled out can only support low-power appliances such as efficient televisions and fans, for example, and the cost of the system, while in many cases affordable to households, remains higher than the price of electricity from the grid. Against this backdrop, there is a need to look beyond the 2030 access target and consider longer term strategies that cater to the growing electricity needs of rural areas. This can be via the grid or through robust mini-grid systems, which can be cheaper per kilowatt-hour (kWh) for households given the larger load, and which are more able to provide for households as they move beyond a basic level of consumption.

2.7 Is natural gas a fuel in good shape for the future?

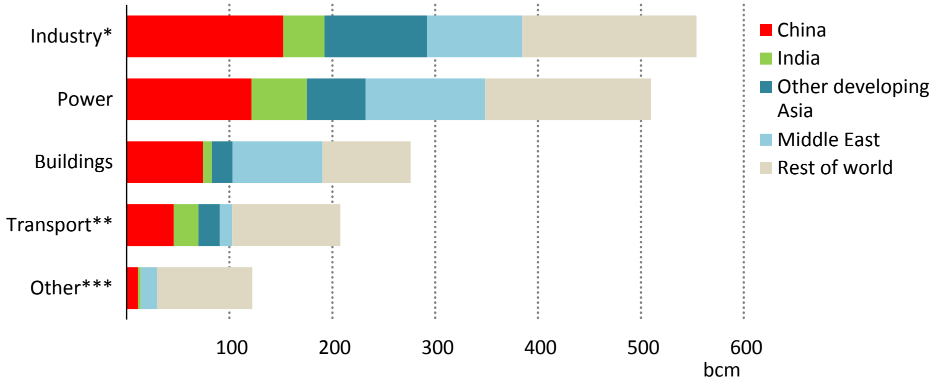
In 2011, the first in the series of the *World Energy Outlook Special Reports* asked the question: "Are we entering a Golden Age of Gas?", examining the combination of market dynamics and policies that might allow natural gas to thrive in the future. The idea of a "Golden Age" was built on a few pillars. On the supply side, the main thesis was that the abundance of unconventional gas resources would help to bring down supply costs, making natural gas more attractive and accessible worldwide. On the demand side, the main elements were an ambitious policy promoting gas use in China, lower growth in nuclear power and more use of gas in road transport.

Six years later, most of these pillars are at least partly in place. Today's price levels are very much in line with those in the "Golden Age" analyses; China has reserved a strategic role in its energy policy for gas; the outlook for nuclear has indeed faded somewhat; the only area where natural gas has not made much ground is road transport (where low oil prices have stymied fuel switching). Yet the mood in some parts of the natural gas industry, at least outside the United States (see section 2.2), is far from golden. Growth in demand has slowed noticeably, from an average of 2.8% per year between 2000 and 2010 to 1.4% per year since then, while continued additions to supply have pushed prices down. Even with low prices, the competitive landscape for gas appears formidable, not just in the shape of its traditional sparring partners, coal and, to a lesser extent, oil, but also the rising forces of renewables and energy efficiency that are garnering strong policy support.

A positive attribute of gas is its versatility: it can play multiple roles across the energy system in a way that no other fuel or technology can match, generating power, heat, and mobility with fewer CO_2 and pollutant emissions than other fossil fuels. However, the flip side of this versatility is that it has competitors in every part of the market. It also requires dedicated and relatively costly infrastructure; its low energy density means that the costs of transportation are a much larger component of the cost of the delivered product than for coal or oil.

In the New Policies Scenario, global natural gas consumption expands at an average rate of 1.6% per year to 2040, much more rapidly than the growth projected for oil or coal. Much of this growth takes place in developing economies, led by China, India and other countries in Asia (Figure 2.15). In these countries, much of the gas needs to be imported (and so transportation costs are significant); infrastructure is often not yet in place; and policy-makers and consumers are sensitive to questions of affordability. While the case for gas in resource-rich countries (as in the Middle East) is evident, prospective sellers of gas in Asia need to produce a strong case to embed gas in national strategies and consumer preferences.

Figure 2.15 ▷ Growth in natural gas demand by sector and by region in the New Policies Scenario, 2016-2040



More than 80% of projected gas demand growth to 2040 is in developing economies across Asia, Middle East, Africa and Latin America

* Includes gas used as feedstocks and energy consumption in blast furnaces and gas-to-liquids process. ** Includes bunker demand. *** Includes agriculture and other non-energy use.

The growth areas for natural gas in our projections, perhaps counter-intuitively, do not start with power generation, although this is currently the largest gas-consuming sector worldwide. In the New Policies Scenario, the largest increase in gas demand comes instead from industry. Where gas is available, it is very well suited to meeting industrial demand. Competition from renewables is limited, especially for provision of high-temperature heat. Gas typically beats oil on price, and beats coal on convenience and on emissions (notably for air pollutants, a major policy consideration in many developing economies). A similar combination of convenience and environmental advantages helps gas to displace household coal consumption for heating and as a cooking fuel; it is also increasingly used for desalination in the Middle East. Gas also has potential as a lower emissions alternative to oil for transportation, especially for heavy-duty vehicles and for maritime transport.

Almost one-third of the incremental consumption of gas over the *Outlook* period comes from gas-fired power plants. An advantage of such plants is their relatively low capital cost, which, depending on relative prices, can offset the typically higher cost of fuel. Yet, only where gas prices are low (e.g. in the United States, Russia and parts of the Middle East) is it commercially viable for gas plants to run at high utilisation rates and provide baseload power. In most gas-importing regions, as the share of wind and solar grows the primary role of gas plants is to provide mid-load and peak load power, implying lower utilisation rates and hence lower gas burn.

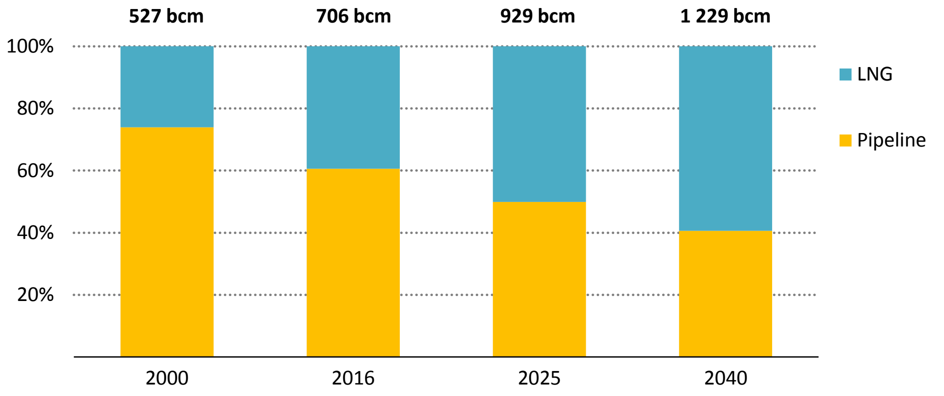
For natural gas to gain a firm foothold in these new markets, it is of crucial importance that suppliers keep the cost gap to alternative fuels, including solar and wind, as narrow as possible. Changes on the supply side are indeed putting downward pressure on prices and increasing the comfort that importers can feel in the future security and diversity of supply. A period of ample availability of LNG, driven largely by new liquefaction capacity in Australia and the United States, is deepening market liquidity and the ability to procure gas on a short-term basis. New projects and exporters are increasing the range of potential suppliers and competition for customers. Destination-flexible US exports, and a firm stance from Japan's Fair Trade Commission in favour of the right to resell LNG, are reducing the rigidity of LNG trade. More and more gas is being priced on the basis of benchmarks that reflect the supply-demand balance for gas, rather than the price of alternative fuels. The contours of a new, more globalised gas market are becoming visible.

This re-writing of the gas rulebook is creating uncertainty for some producers, who have claimed that long-term contracts indexed to oil prices and other trade rules (notably take-or-pay clauses) are vital for the financing of capital-intensive upstream and infrastructure projects. In Chapter 9, we argue that the emergence of a new, more flexible gas order, the rise of major company "aggregators" that maintain a diverse global portfolio of gas sources and market positions, and a marked shift towards LNG are interdependent developments. The risk of a shortfall of investment in new supply is real, but in our judgement there is scope for brownfield project expansions and smaller, less capital-intensive projects in the LNG business to underpin project development in the next ten years and prevent a hard landing for markets in the 2020s. As gas trade expands by more than 500 bcm over the period to 2040, LNG's inherent flexibility gives it the edge over most new cross-border pipeline projects and, as a result, LNG meets the lion's share of the growth in long-distance gas trade in the period to 2040 (Figure 2.16). Although the European Union remains the largest importer of gas, the Asia Pacific region accounts for some 80% of the growth in net-imports.

The case for natural gas encompasses a strong environmental dimension. Combustion of natural gas does produce some nitrogen oxides (NO_X), but emissions of the other major sources of poor air quality, particulate matter and sulfur dioxide, are negligible. The combustion of gas releases some 40% less CO_2 than the combustion of coal and around 20% less than the burning of oil. Taking into account the efficiency of transforming thermal energy into electricity, a combined-cycle gas turbine emits around 350 grammes of CO_2

per kilowatt-hour, well under half of what a supercritical coal plant emits for the same amount of electricity. Gas-fired power plants have technical and economic characteristics that make them a very suitable partner for a strategy favouring the expansion of variable renewables.

Figure 2.16 ▷ Global gas trade by mode in the New Policies Scenario



Almost 90% of additional gas trade in the period to 2040 is in the form of LNG

However, the industry cannot take it for granted that environmental arguments work in its favour. Methane – the primary component of natural gas – is also a potent greenhouse gas and emissions of methane along the oil and gas value chain (which are estimated for 2015 at around 76 Mt of methane) threaten to reduce many of the climate advantages claimed by gas. In Chapter 10, we present first-of-a-kind marginal abatement cost curves for methane emissions from oil and gas operations, which suggest that around 40-50% of today's emissions from the oil and gas sector could be avoided using approaches that have zero or negative costs (because the captured methane can be sold). Implementing just the cost-effective oil and gas methane measures in the New Policies Scenario would have the same impact on reducing the average global surface temperature rise in 2100 as immediately shutting all existing coal-fired power plants in China. If natural gas is to play a credible role in the transition to a decarbonised energy system, this is an opportunity for action that cannot be ignored (Box 2.6).

Ultimately, the prospects for natural gas will be determined by how it is assessed by policy-makers and prospective consumers against three criteria: is it affordable, is it secure, and is it clean? In each of these areas, there is homework for the industry to do, to keep costs under control, to ensure adequate and timely investment, and to tackle the issue of methane emissions. If the answers to these questions are positive, then gas can make a persuasive pitch for a place in countries' energy strategies, underpinning further infrastructure development and opening new opportunities for growth.

Box 2.6 ▷ Does gas still work as a "bridge" in a world of cheap renewables?

Are cheap renewables a friend or a foe for natural gas? The answer in our scenarios, including the Sustainable Development Scenario, is that they find a way to work together. As the cleanest burning fossil fuel and one that emits few local air pollutants, natural gas fares best among the fossil fuels in the Sustainable Development Scenario, with consumption increasing by nearly 20% between 2016 and 2030 and then remaining broadly flat to 2040. The contribution of natural gas to decarbonisation in this scenario varies across regions, between sectors and over time. In energy systems that are currently heavily reliant on coal, notably in China and India, natural gas can play a sustained role. It has less potential to help emissions reduction in more mature gas markets, although in the United States and Europe there is a window of opportunity for gas to aid decarbonisation by accelerating the switch away from coal. Nevertheless, with the rapid ascent of low-carbon technologies in this scenario, the principal function of gas is to provide flexibility to support the integration of variable renewables. For some industrial applications, and in some parts of the transport sector, the "bridge" for gas is a much longer one, as cost-effective renewable alternatives are less readily available.

2.8 *Can oil prices stay lower for much longer?*

The future trajectory for oil prices, both their average level and their volatility around this level, is a critical uncertainty for any forward-looking energy analysis. In the New Policies Scenario, the balance of forces on the demand and supply side suggests some upward pressure on the oil price, which reaches $83/ barrel by the mid-2020s (see Chapter 1). But changing some of the key variables would allow the price to stay lower for longer and, two years on from the Low Oil Price Scenario that was examined in detail in the *WEO-2015*, we return to the question: under which circumstances could lower oil prices persist, not just for a few years, but for a decade or more?

On the demand side, a vital component of an extended low oil price outlook would be a major disruptive shift, with electric mobility the obvious candidate for such a role. In the New Policies Scenario, the global electric car fleet expands rapidly, by over 50% each year to 2020. By 2025, there are nearly 50 million electric cars on the road, significantly reducing the cost of batteries and improving the competitiveness of electric cars, although policies to roll out recharging infrastructure remain a key bottleneck for a more rapid uptake of electric cars in the longer-term. In a Low Oil Price Case (described in more detail in Chapter 4), we assume that such deployment hurdles are overcome so that, by 2040, there are close to 900 million electric cars[4] on the road (from around 2 million today) compared with a fleet of around 280 million in 2040 in the New Policies Scenario.

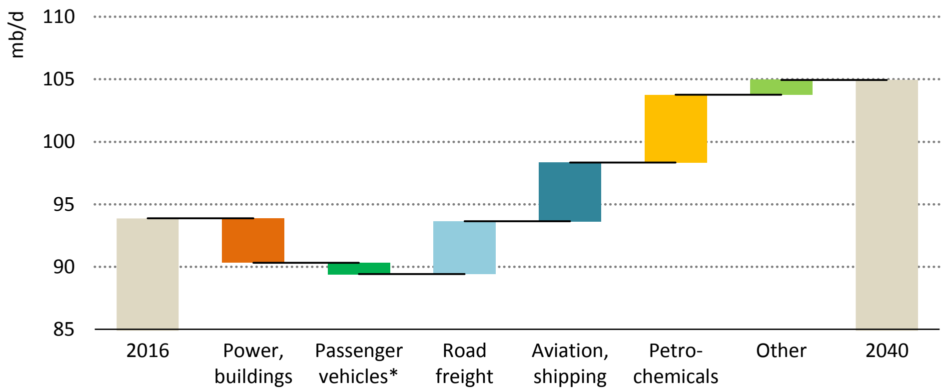
4. This is the size of the electric car fleet in 2040 in the Sustainable Development Scenario.

On the supply side, the main disruptive element is already in place: the US tight oil industry has emerged from its trial by fire since 2014 as a leaner and hungrier version of its former self, remarkably resilient and reacting quickly to any sign of higher prices caused by OPEC's return to active market management. The extent to which tight oil can balance the market at lower prices over the long term depends to a significant degree on the assumed size of the resource base. In the New Policies Scenario, we use the latest resource numbers from the US Energy Information Administration (which provide a resource base of 105 billion barrels). But estimates are uncertain, particularly for some of the most prolific plays such as the Permian Basin in the southern United States, and so in the Low Oil Price Case, we assume a tight oil resource of twice the size, of 210 billion barrels. The consequent ability for the United States to produce more, at lower cost, allows tight oil to maintain downward pressure on prices long enough for the structural changes on the demand side to work their way through. A second supply-side pillar of the Low Oil Price Case is an accelerated pace of technology learning across the upstream sector as a whole, reflecting the possibility that the widespread application of digital technologies (among other possible technological innovations) could keep a lid on upstream costs. This case also requires a favourable view about the ability of the main oil-producing regions to weather the storm of lower hydrocarbon revenues.

With these assumptions in place, we find that the oil market can find a longer term equilibrium in the range of $50-70/barrel (in real terms). Until the mid-2020s, the story in the Low Oil Price Case is mainly supply-driven, with more US tight oil surging into the market in the event of any upswing in prices. This keeps the average price in the low $50s/barrel, even though global consumption is higher than in the New Policies Scenario as consumers take advantage of the lower prices. From the late 2020s the picture changes as rapid growth in the electric car fleet starts to make a significant dent in the trajectory for oil demand, which flattens around 103 mb/d, although there is still no major reduction in oil use as consumers continue to find it advantageous to consume oil in other sectors.

The New Policies Scenario features many of the same dynamics, with strong growth in the electric car fleet and in US tight oil, but their impact is not sufficient to outweigh other forces that tighten the oil market balance. On the demand side, a peak in the amount of oil used for passenger vehicles is already visible in this scenario, even as the global passenger car fleet doubles to 2040, due mainly to efficiency gains but also because of fuel switching and continued rapid growth in the electric vehicle fleet. The 280 million electric cars on the road by 2040 ultimately displace some 2.5 mb/d of potential oil consumption, and oil use in buildings and for power generation likewise declines. However, total oil demand continues to rise – albeit at a slowing pace – all the way through to 2040 because of continued growth in other sectors: the use of oil products as petrochemical feedstock (up by 5.4 mb/d compared with today), as fuel for trucks (+3.9 mb/d), aviation (+3.3 mb/d) and ships (+1.4 mb/d) (Figure 2.17). In the New Policies Scenario, total oil demand rises to 105 mb/d in 2040; if biofuels are included, total liquids demand reaches 109 mb/d.

Figure 2.17 ▷ Change in world oil demand by sector in the New Policies Scenario



While the outlook for oil in power generation, buildings and passenger vehicles hints at a peak in oil demand, this is more than offset by rising demand in other sectors

* Includes passenger cars, two/three wheelers and buses.

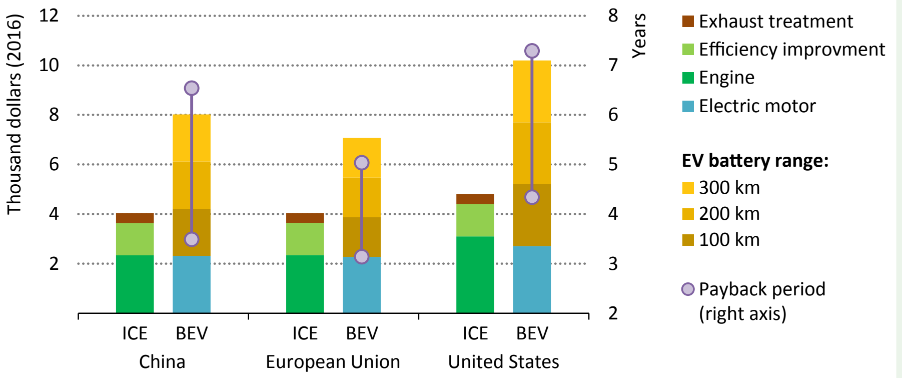
Three elements differentiate the growth in electric cars in the New Policies Scenario from the Low Oil Price Case. The first is the economics: this is in part a question of battery costs, which play an important role in determining the additional costs of electric cars compared with their conventional counterparts, but which are already close to their floor of $80-$100 per kilowatt-hour by 2025 in both cases (Box 2.7). A low oil price, however, reduces the advantage that electric cars have on running costs and makes the economic hurdle harder to overcome. Second is the helping hand that policy-makers can provide to close any value gap that exists between electric cars and conventional vehicles – this gap closes fast for segments with high usage, such as taxis, government or company fleets or vehicles used for ride-sharing, but can be significant for cars that are driven less often. In the Low Oil Price Case, it is assumed that governments step up significantly their efforts to support the uptake of electric mobility and/or further limit the expansion of gasoline-fuelled vehicles. Third, significant support is required to build up recharging infrastructure of sufficient density; this is likewise assumed to be in place in the Low Oil Price Case. These three elements determine the tipping points at which electric vehicles become as cheap and as attractive for a mass-market as gasoline-fuelled vehicles.

On the supply side, the fiscal and social strains of an extended period of lower prices are starting to show in many resource-rich countries. However, another key element of risk in today's market is the contrast between the extraordinary dynamism of US tight oil, on the one hand, and the slump in investment activity in more traditional sources of production, on the other. This two-speed oil market is not sustainable if the current period of lower prices is to last. If conventional project approvals do not pick up, then the surge in US tight oil would face the daunting task of compensating, largely on its own, not only for demand growth but also for the continual drain on supply caused by declining production from existing fields. Post-peak decline rates averaging around 6% per year means that the world needs to find an additional 2.5 mb/d of new production each year, just for conventional output to remain flat. Decline rates for tight oil are considerably higher.

Box 2.7 ▷ When could electric cars beat conventional cars?

The production costs of electric cars are on a rapid downward trend, as increased market share brings economies of scale and battery costs fall. Meanwhile, conventional internal combustion engine (ICE) cars are expected to become more expensive due to more stringent fuel-economy and air pollutant emissions standards. These costs are on a converging trajectory: the uncertainty is over when they might cross. In our projections, battery costs fall towards a floor of $80-100 per kilowatt-hour (kWh); however, the capital cost of a battery electric vehicle (BEV) with a drive range of 200-300 kilometres (km) in real-driving conditions, remains higher than a corresponding conventional vehicle in 2025 (Figure 2.18). The size of this gap varies by region: the typical consumer preference for large and more powerful cars in the United States requires larger battery sizes, penalising the competitiveness of electric drivetrains, whereas the smaller cars in the European Union, Japan and India narrow the difference in production costs.

Figure 2.18 ▷ Powertrain cost comparison of conventional and electric cars in selected regions in the New Policies Scenario, 2025



Capital costs for electric cars remain higher than for conventional cars in 2025, but lower running costs can still make payback periods attractive for consumers

Notes: ICE = internal combustion engine (gasoline); BEV = battery electric vehicle. For electric cars, electric motor bar also includes electronics cost. The drive range displayed corresponds to 2017 US Environmental Protection Agency estimates, close to real-driving conditions. For each region, payback period range is based on the average-size BEV with a drive range varying between 200 km and 300 km.

Fuel expenditure savings offer an important competitive edge for electric vehicles. The extent of these savings depends on the oil price, the level at which gasoline is taxed and the annual mileages for the vehicles concerned. Based on the economics, electrification of mobility is likely to proceed most quickly for cars with high usage rates, in countries that tax fuel heavily. But, by 2025, the economic calculation can start to look attractive for other segments as well: in the European Union, the additional up-front investment for a typical household electric car in 2025 (with a drive range of 200-300 km) would be paid back in around four years, due to lower running costs. By the mid-2030s, this type of payback period would also be within reach for consumers in India and Japan (and a little later in China).

The extent to which consumers then take up what might look like a reasonable economic proposition would then be based on other factors. A crucial consideration would be the ready availability of the necessary recharging infrastructure. In addition, BEVs could be fully cost-competitive with ICEs if consumers were ready to further compromise on drive range (cutting battery costs) and attributes like size or power (cutting energy storage requirements, and therefore resulting in lower battery costs). This could come about either because of a shift in preference or because of policy incentives that promote the use of electric vehicles, particularly in cities. An increasing number of such policies are being put in place to combat air pollution (see Chapter 4).

With the fall in upstream spending since 2014, we are now into a third year where investment decisions on new conventional projects are thin on the ground. This is not affecting global supply for the moment because conventional projects tend to have long lead times of three to six years: the projects ramping up today were typically approved before the oil price fell in late 2014 (the continued growth in current Brazilian output provides a good example). The outlook for global supply in the early 2020s therefore depends on the readiness of the industry to approve new projects at today's price levels.

In the Low Oil Price Case, risks on the supply side are eased by the higher resource estimates for tight oil, which let the United States step in with additional volumes, and by the faster technology learning in the upstream, which allows the industry as a whole to lock in a greater share of the cost reductions seen in recent years (the capital costs of upstream oil and gas projects around the world fell by around 40% between 2014 and 2016, as a result of technological improvements and a drop in unit costs). As a result, new non-OPEC projects can come through at lower prices. Even so, this scenario also requires higher production from the Middle East, the largest global source of low-cost oil.[5]

5. The Sustainable Development Scenario avoids too great a strain on the supply-demand balance primarily because oil demand peaks by 2020, which means that there is less need to develop new projects and US tight oil (even with a smaller estimated resource base) can take up much more of the slack in the market.

However, in the New Policies Scenario, the industry needs to increase upstream spending more sharply to meet rising levels of oil consumption. In this environment, supply and services markets tighten and companies have to move on to new projects that are naturally more costly, because they are more complex and less productive. Even with continued technological innovation, our expectation in the New Policies Scenario is for a rebound in capital costs, a major underlying reason for the anticipated rise in prices.

The dilemma for oil markets is that today's demand indicators – absent a major technology shift of the sort discussed above – are mostly pointing to a world of continued growth (resembling the New Policies Scenario or the early years, at least, of the Low Oil Price Case). However, the forward-looking indicators for supply – with the exception of tight oil – are struggling to keep pace. The volume of conventional resources being approved for development is running at well under 10 billion barrels per year. This is less than half of the 20 billion barrels that would be required annually to balance the market to 2025 in the New Policies Scenario, a requirement that is not too different in the Low Oil Price Case.[6]

An oft-heard warning for the future of oil is that the oil industry is unprepared for a world in which demand will surprise them on the downside. This cannot be excluded. However, our analysis also suggests the opposite possibility; that the investments actually being made by companies are, for the moment, well short of what is needed to ensure a soft landing for markets in the 2020s, and it is the world's consumers that could be in for a nasty surprise. The irony is that such a spike in oil prices, if it comes, could also be the shock that propels electric mobility firmly into the mainstream.

2.9 Is the future switching towards electricity?

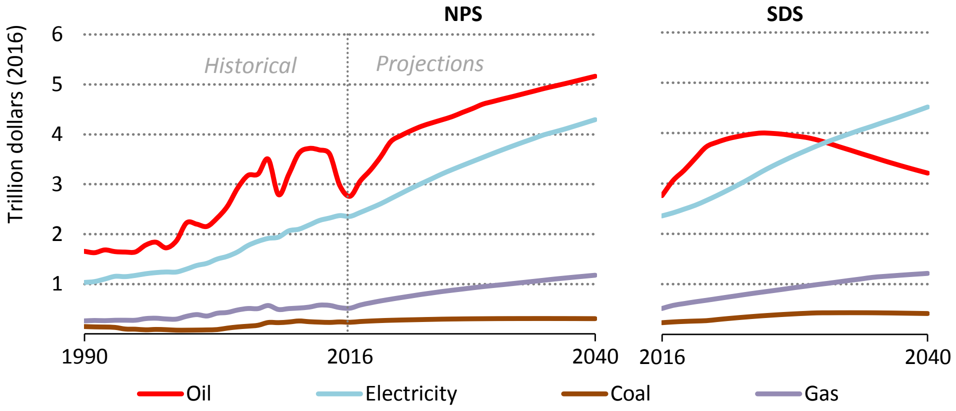
In 2016, capital expenditure in the power sector, including generation and transmission investment, amounted to around $720 billion, overtaking for the first time the $650 billion invested in the global oil and gas sector (IEA, 2017a). The data for 2016 reflect some extraordinary pressures on the upstream oil and gas sector, as lower prices and revenues took their toll on drilling activity (which typically makes up around two-thirds of total spending in the oil and gas sector); the lower headline figure for oil and gas investment also incorporates a sharp reduction in costs in many areas. However, cost reductions for renewable technologies likewise pushed down the investment required in the power sector, alongside a drop in spending on new coal-fired projects. Were the 2016 data a blip or a sign of things to come? Is this switch towards electricity borne out in the *WEO* projections?

What is certainly visible in all scenarios is an increasing role for electricity in final consumption. Rising incomes tend to increase appliance ownership rates, and an increasing number of end-uses are electrified, especially in scenarios that have stronger policies for decarbonisation. Electricity accounts today for just under 20% of global final

6. The current rate of approvals is even below the 11 billion barrels that would be required annually to balance the market to 2025 in the Sustainable Development Scenario.

consumption. This share grows to 23% in both the New Policies Scenario and the Current Policies Scenario by 2040, while in the Sustainable Development Scenario it accelerates to 27%. A rising share of electricity in final consumption is not a new trend – it has been going on for several decades. However, the Sustainable Development Scenario sees a significant step up in the share of electricity, compared with historical trends; this is not because the amount of electricity supplied is much larger than in other scenarios, but because the need to decarbonise and use energy more efficiently causes consumption of other fuels to stop growing and even start contracting.

Figure 2.19 ▷ Global end-user energy expenditure by fuel and by scenario



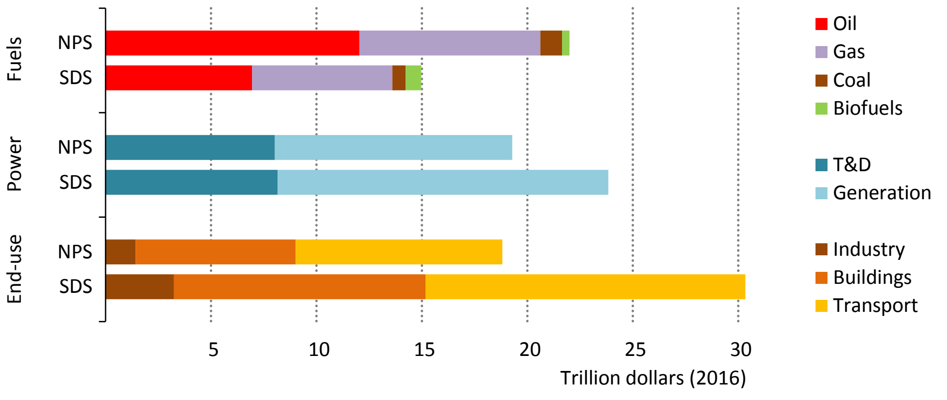
In the Sustainable Development Scenario, electricity becomes the main item in global end-user spending on energy, taking over from oil products

Notes: NPS = New Policies Scenario; SDS = Sustainable Development Scenario. Global end user expenditure is the aggregate of regional expenditures; international bunkers are excluded.

A similar picture emerges from an analysis of end-user spending on energy. This has traditionally been dominated by oil products, but with the fall in oil prices since 2014, our estimates show an unprecedented closing of the gap at global level between the amounts that consumers spend on oil products versus electricity (Figure 2.19). How this evolves depends on the scenario. In both the New Policies Scenario and the Sustainable Development Scenario, consumer spending on oil products worldwide is projected to increase as demand continues to rise and oil prices recover somewhat. However, from the early 2020s the trends start to diverge. Oil products retain their primacy in end-use expenditure in the New Policies Scenario, while electricity takes over in the Sustainable Development Scenario as its share in end-use consumption rises and the use of oil products for passenger transport starts to decline. The tipping point comes earlier in some regions than others (in the European Union, for example, the crossover to electricity is observed already in the New Policies Scenario), but it becomes a global phenomenon.

In terms of the balance of investment between the power sector and oil and gas, the New Policies Scenario eventually reverts to a greater share for the latter (Figure 2.20). Investments required in oil and gas supply edge higher as demand continues to grow and the supply chain starts to tighten, with total capital spending approaching the levels seen prior to 2015. An annual average of $860 billion is required worldwide in the oil and gas sector to 2040, of which $640 billion is in the upstream. The level required in the Current Policies Scenario is even larger, as higher demand means that the industry needs to access higher cost resources. However, the share of the power sector in total supply investment in the New Policies Scenario is around 47%, well above the historical average of 41% (Table 2.3).

Figure 2.20 ▷ Cumulative global energy investment by scenario, 2017-2040



Investment in the power sector is substantially larger than spending on oil and gas supply in the Sustainable Development Scenario

Note: NPS = New Policies Scenario; SDS = Sustainable Development Scenario; T&D = transmission and distribution.

The Sustainable Development Scenario witnesses a more profound long-term shift in investment flows, in which the primacy of spending on electricity in 2016 becomes the norm. In this scenario, investments in electricity surge, led by a strong increase in renewables-based power (by 80% compared with today's levels, despite continued falls in technology costs) and higher investment in nuclear as well as thermal power plants equipped with carbon capture and storage (CCS). Overall, in the Sustainable Development Scenario, the power sector accounts for over 60% of energy supply investments, as capital expenditure on upstream projects (for oil in particular) declines on the back of lower demand as well as lower production costs. Even though their share in total energy supply investment falls, the Sustainable Development Scenario still requires almost $14 trillion in capital expenditure on oil and gas supply; declining output from existing fields creates a sizeable gap that needs to be filled by new upstream projects.

The other side of the reduced requirement for supply-side investment in the Sustainable Development Scenario is a significant increase in spending in end-use sectors, mainly on improvements in energy efficiency. As policies and standards become increasingly widespread and stringent in this scenario, so the investment required to comply also rises sharply (measured as the cost of incremental improvements in efficiency for different end-use equipment versus a baseline of their respective efficiency levels in 2015). The two largest sectors for such investment are transportation, where it mostly represents the incremental cost of more efficient cars and trucks, and in the buildings sector, where it is required both for more efficient appliances and for better building insulation and energy performance. Compliance only with policies and measures in place today, as in the Current Policies Scenario, reduces the required spending on efficiency considerably, especially in the buildings sector.

Table 2.3 ▷ Global energy investment by type and scenario, 2017-2040 ($2016 billion)

	2010-16	New Policies		Current Policies		Sustainable Development	
	Per year	Cumulative	Per year	Cumulative	Per year	Cumulative	Per year
Fossil fuels	1 103	24 713	1 007	29 932	1 247	15 496	646
Renewables	297	7 950	331	6 350	265	12 828	534
T&D	236	8 025	334	8 524	355	8 145	339
Other low-carbon	14	1 127	47	1 095	46	2 325	97
Supply	**1 650**	**41 276**	**1 720**	**45 901**	**1 913**	**38 795**	**1 616**
Power sector share	*41%*		*47%*		*41%*		*63%*
Oil and gas share	*54%*		*50%*		*55%*		*35%*
End-use	**295**	**18 809**	**784**	**11 912**	**496**	**30 340**	**1 264**

Notes: The methodology for efficiency investment derives from a baseline of efficiency levels in different end-use sectors in 2015; the historical value for end-use spending includes only 2016. T&D = transmission and distribution. Other low-carbon includes nuclear and CCS. Oil and gas share includes upstream, transportation and refining. The elements not covered by the percentages for oil and gas and power shares include biofuels supply and coal mining and transportation.

Each scenario requires a sustained, substantial allocation of capital to electricity networks, although the nature of this spending varies by scenario. In the Sustainable Development Scenario, almost 20% of transmission and distribution investment is required by 2040 to meet the specific requirements of a renewables-rich electricity system, compared with around 10% in the New Policies Scenario and less than 5% in the Current Policies Scenario. Transmission and distribution spending in the Sustainable Development Scenario is on a rising trend and ends up 15% higher in 2040 than in the New Policies Scenario, even though electricity demand is almost 10% lower. The network in the Sustainable Development Scenario needs to cater for a larger number of supply projects, with a greater contribution of distributed renewable generation and more complex, decentralised systems for co-ordination and balancing (Box 2.8).

Box 2.8 ▷ Are energy projects getting smaller?

For the energy sector, bigger has usually been better. Economies of scale meant that the large-capacity power plant was a natural partner for the centralised grid. The large hydrocarbon reservoir, if it could be discovered, was the obvious way to meet the world's demand for oil and gas. However, the energy system of the future may not have the same reverence for scale as in the past. In the case of oil and gas, the reasons are partly geological: new discoveries tend to be smaller in size and the remaining large fields tend to be in increasingly remote and inhospitable places. Smaller projects may also be a way to manage uncertainty over the future: if there is a chance that oil demand might peak at some point in the 2020s, companies might well be wary of very large, capital-intensive projects that pay back over decades. The emergence of smaller projects has also been enabled by technology; the falling costs of solar PV and wind power have allowed individual households, communities and businesses to enter the market and help meet their own energy needs.

Is the emerging preference for smaller energy projects likely to be maintained in the coming decades? The geological constraint appears to be binding, at least for conventional projects, and the short investment cycle of shale is set to reinforce a shift towards shorter cycle projects that can be brought to market more quickly. In the Sustainable Development Scenario, the appetite and ability to finance high-cost large-scale upstream projects could well be dampened by lower prices and future demand uncertainty. Nonetheless, the demand outlook in the New Policies Scenario implies a degree of stability to move ahead with larger projects (even more so in the Current Policies Scenario). Large new greenfield projects, especially for gas, do go ahead in this scenario – the large resources in Mozambique's Rovuma basin being a case in point.

In power generation, smaller projects are set to increase in number and importance, especially in the Sustainable Development Scenario, not only because solar PV costs fall but also because related technologies become more available and accessible, such as energy storage, smart meters, connected appliances and electric vehicles (see Spotlight in Chapter 6). This will have major implications for utilities and network operation, but does not mean that the age of the centralised grid is over. In practice, utility-scale projects are likely to continue to make up the lion's share of global power supply and there is no sign yet that these types of projects are getting smaller – indeed the average size of utility-scale renewables projects has been increasing in recent years and this may be reinforced by the recent cost declines for offshore wind. With large-scale nuclear investments also taking up a prominent role in many decarbonisation pathways, including the Sustainable Development Scenario, small projects may well become more important as a feature of the energy landscape, but they are unlikely to have the future to themselves.

2.10 Is offshore energy yesterday's news or tomorrow's headlines?

Is the offshore a major source of energy for the future, or are its best days already behind us? There are arguments to support both points of view. A downbeat assessment would underline the maturity of the main offshore oil and gas provinces – the North Sea, Gulf of Mexico, West Africa; note that investment is down and new developments are struggling to compete in a shale-inspired lower price environment; and observe that offshore wind is still a marginal and relatively expensive element in the global power mix. But there is weight too behind the opposite opinion: an offshore optimist might highlight the recent record of exploration success in some frontier areas, including East and West Africa and the East Mediterranean; point out that costs have been coming down for new oil and gas projects, that Mexico's offshore continues to attract major interest from investors and that Brazil's deepwater output continues to grow despite political turmoil; and emphasise that offshore wind – a vast resource – is gaining support and momentum, with record low bids in recent auctions.

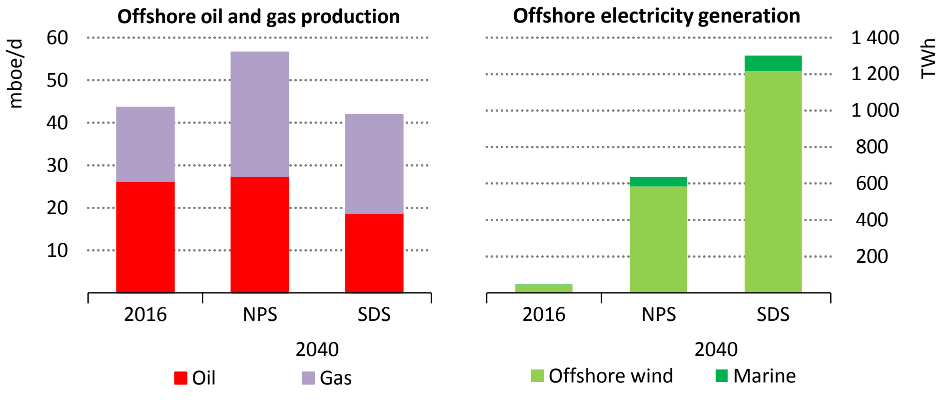
Offshore energy continues to play a major role in meeting the world's needs in all of our scenarios, but our *Outlook* does not offer a definitively positive or negative view for the future, not least because a scenario in which offshore hydrocarbons do well might not be a world in which offshore wind flourishes, and vice versa. But it does offer insights into the potential contribution from a range of offshore resources, as well as an opportunity to consider some potentially noteworthy synergies between them.

Offshore oil production has remained steady at around 26-27 mb/d over the last ten years, which in a world of rising demand means that its share of total oil output has declined somewhat, dipping below 30%. In the New Policies Scenario, production stays at around this level, but there is a shift from shallower to deepwater plays.[7] Mexico provides a good example of this dynamic: a longstanding shallow water producer, the main fields are mature and facing rapid declines and the main source of future growth is anticipated to come from new deepwater opportunities offered in the country's licensing rounds. Elsewhere, Brazil is the main source of global growth in deepwater output, although there are smaller contributions from other countries. In today's oil market, the attraction of new deepwater oil investments has been diminished by their capital intensity and long payback periods. In response, producers are working to simplify, standardise and downsize projects, but ultimately the rise in oil prices in the New Policies Scenario plays a big part in helping deepwater investment make a comeback. In the Sustainable Development Scenario, the market and price environment continues to mitigate against complex projects with long lead times: the outlook for offshore oil is more muted and production falls back to 20 mb/d by 2040 (Figure 2.21).

7. Shallow water fields are at water depths less than 400 metres, deepwater fields at greater than 400 metres depth (can be further categorised into ultra-deepwater at depths greater than 2 000 metres).

The starting point for natural gas is similar to that of oil: offshore projects account for around 30% of gas production worldwide, totalling more than 1 trillion cubic metres per year. However, the outlook is slightly more upbeat, with offshore gas production increasing to 1 730 bcm in the New Policies Scenario by 2040 and to almost 1 400 bcm in the Sustainable Development Scenario. The share of offshore in total gas production rises slightly in both cases. These outcomes have a lot to do with the impressive record of recent gas discoveries. Deepwater has accounted for around half of the hydrocarbons discovered worldwide over the last ten years and, aside from Brazil, the large majority have been gas, including the Zohr field off Egypt, the East Africa discoveries off Tanzania and Mozambique, and recent gas finds off Mauritania and Senegal. In our projections, these developments, together with substantial growth from Iran and Qatar in the Middle East and increases from Russia and the Caspian Sea, all push offshore gas production higher.

Figure 2.21 ▷ Global offshore production and generation by scenario



Major recent offshore discoveries keep gas production afloat in both scenarios, while Europe and China power the growth in offshore wind

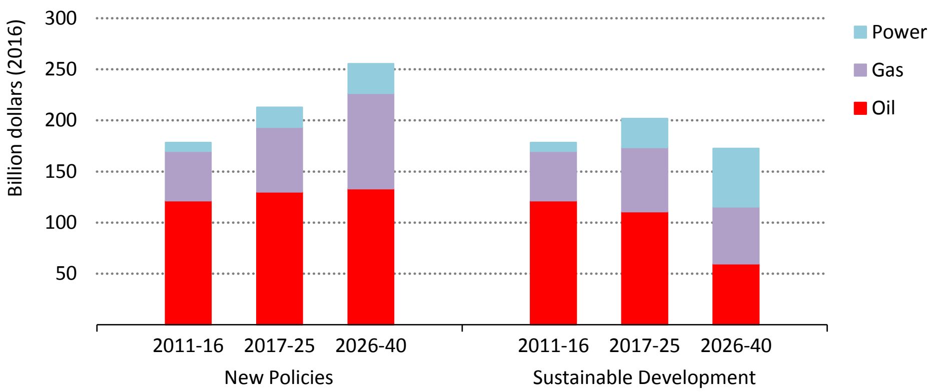
Note: NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

Offshore power generation technologies included in the *Outlook* include offshore wind and marine power generation (tidal and wave), but the projected growth is concentrated in offshore wind. At the end of 2016, there was around 14 GW of offshore wind capacity installed worldwide, generating over 45 terawatt-hours (TWh) of electricity. In the New Policies Scenario, this contribution grows to around 160 GW and 580 TWh, respectively, by 2040. Growth in the Sustainable Development Scenario is even more rapid, to 350 GW of capacity and more than 1 200 TWh of generation. Deployment of marine technologies picks up after 2030 but from a very low level, and with costs remaining relatively high compared with other low-carbon options in our *Outlook*, marine remains a marginal source of power generation.

Europe dominates the growth in offshore wind in the New Policies Scenario, accounting for over half of global capacity additions, followed by China. Europe is well suited for the development of offshore wind, with relatively shallow waters available for development, readily available expertise from existing North Sea offshore developments and easier access to existing transmission grids than in most other regions. Recent auction price developments confirm the momentum in the European offshore wind sector (see also Chapter 6), with record low bids for power purchase agreements in Denmark (EUR 50 per megawatt-hour [MWh]), Netherlands (EUR 55/MWh), United Kingdom (EUR 65/MWh) and Germany (the project developers were not asking for any price guarantees or subsidies for the electricity produced, relying solely on revenues from the market). In the Sustainable Development Scenario, growth in offshore wind in Europe is higher but offshore activity in the Asia Pacific region takes off, led by China but including also other countries such as India, Indonesia, Japan and Korea. The United States and other parts of the North America also see significant growth in this scenario.

Investment in offshore oil and gas projects is roughly similar across the two scenarios until the mid-2020s, when the difference in overall demand and activity starts to be of note. Offshore power generation investment grows across the board, but ends up twice as high in 2040 in the Sustainable Development Scenario (Figure 2.22). In general, offshore investment in power generation remains significantly smaller than total offshore oil and gas upstream investments, although the gap narrows towards the end of the projection period. In some regions this gap narrows much more quickly: in the North Sea, for instance, oil investments fell to less than $25 billion in 2016, about half the level of 2014, while the estimated level of spending in North Sea offshore wind projects doubled to about $14 billion between 2014 and 2015.

Figure 2.22 ▷ Average annual offshore energy investment by scenario



The fall in offshore oil investment in the Sustainable Development Scenario is offset in part by growth in spending on offshore wind power projects

These patterns of investment, especially the way that investment in renewables rises to fill part of the gap left by falling oil and gas investment in the Sustainable Development Scenario, offers a reassuring perspective for companies engaged in the offshore sector. There are several overlapping competencies that are required for successful development of offshore wind and oil and gas projects: project execution and engineering skills, ability to manage harsh offshore conditions, and knowledge of seabed and underwater conditions. Both types of projects have a long-term time horizon of twenty years or more, and require similar support services (e.g. ports, maintenance services). But there are also some key differences across the different types of offshore project. Expected project returns and risk profiles are quite distinct, and project locations may not coincide in practice. Offshore wind projects tend to be located close to shore and potential consumers, while oil and gas projects are generally projected to move further offshore into deeper waters, with the resulting product often transported over long distances. However, where these resources and projects overlap, there is considerable potential for an integrated approach (Box 2.9).

Box 2.9 ▷ Is there a chance to join up the offshore dots?

Today the offshore hydrocarbon and wind power sectors are not closely interlinked. Could they benefit from better integration? In theory, the possibilities are broad, spanning infrastructure, offshore services, human capital, technology, products and knowledge, but the practical challenges are significant. A first step towards integrating the two sectors would be to supply existing oil and gas platforms with electricity from nearby offshore wind installations, with the short distances meaning lower costs for transporting the electricity as compared with an onshore grid connection. For example, electrifying 10 of the 40 platforms with the highest energy needs in the Netherlands' platforms in the North Sea would require around 1.4 TWh per year; this demand could be met by a 400 MW wind farm (assuming a 40% capacity factor) and reduce average CO_2 emissions by around 1 million tonnes per year.

Integrated approaches could also reduce costs by combining maintenance staff and co-ordinating supply chains: looking further ahead, there is also scope to use existing oil and gas infrastructure (platforms, cables, pipelines) and (near) empty oil and gas reservoirs for new applications. These could include power-to-gas or hydrogen from gas (with the carbon being stored in the reservoirs), system integration and improvements to the maritime ecosystem. As usual with early-stage technologies and ideas, there is a need for policy support and pilot initiatives to see if these concepts can be proven, both technically and commercially.

Energy, emissions and universal access

En route to a sustainable energy sector

Highlights

- The internationally agreed Sustainable Development Goals (SDGs), adopted in 2015, aim to end global poverty, protect the planet and ensure economic prosperity for all. For the first time, energy has a dedicated goal (SDG 7), as well as being instrumental for achievement of many of the other goals, including addressing climate change (SDG 13) and reducing air pollution (SDG 3.9). These objectives need to be reached while ensuring secure supplies of energy at an affordable price.

- In the New Policies Scenario, the energy sector makes progress towards meeting these goals, but falls short. Energy-related CO_2 emissions rise by 0.4% per year through to 2040. CO_2 emissions from advanced economies plateau or decline, but emissions are pushed upwards in other countries by economic growth. Emissions of air pollutants fall, but health impacts remain severe. Premature deaths from outdoor air pollution rise from 2.9 million today to 4.2 million in 2040.

- Today, 1.1 billion people lack access to electricity and 2.8 billion do not have access to clean cooking facilities, both critical impediments to human development and health. In the New Policies Scenario, India fulfils its objective of electricity access for all by the early 2020s, but in sub-Saharan Africa universal access remains elusive, as population growth outpaces new connections; around 700 million people are without electricity in 2040. The number of people without clean cooking facilities falls to less than 2 billion in 2040, but premature deaths linked to breathing noxious fumes while cooking are still high (2.3 million, down 17% from today).

- This year's *WEO* presents a new Sustainable Development Scenario, the aim of which is to address the three interlinked goals of achieving universal energy access, limiting climate change and reducing air pollution, alongside enhancing energy security. As an IEA input to the Sustainable Development Agenda, we propose concrete and pragmatic integrated policies to put the world on track towards these goals.

- In the Sustainable Development Scenario, achieving universal energy access at least-cost has no net impact on GHG emissions. Coal use peaks before 2020 and oil use soon after; natural gas becomes the main fossil fuel. Power generation is mostly decarbonised by 2040, relying on renewables (over 60%), nuclear power (15%) and CCS (6%). Renewables and natural gas provide more than 80% of installed capacity by 2040. The electric car stock rises to around 875 million cars by 2040, three-times more than in the New Policies Scenario. Investment needs in supply and end-uses are 15% higher through to 2040, at nearly $70 trillion, but fossil-fuel import bills and consumer energy expenditure are lower. Premature deaths related to outdoor air pollution are cut by 1.6 million.

3.1 Introduction

Energy is pervasive to all aspects of human life – it fuels economic activity and boosts productivity to support global growth, while providing essential services to individuals and households that improve their living standards. The rate of global economic growth over the past century has been closely linked to the rate of growth in energy demand, lifting billions of people worldwide out of poverty. But the quest to provide modern energy services to all is far from over: recent *World Energy Outlook (WEO)* analysis shows that there are 1.1 billion people who still lack access to electricity and 2.8 billion people do not have access to clean cooking facilities (IEA, 2017a).

Achieving universal access to affordable, reliable and sustainable energy is widely recognised as an essential step towards ending global poverty. The United Nations (UN) 2030 Agenda for Sustainable Development, a successor to the UN's Millennium Development Goals, was adopted in 2015. It includes a set of 17 Sustainable Development Goals (SDGs) to end poverty, protect the planet and ensure prosperity for all, along with specific targets to be achieved in the period to 2030. For the first time, affordable and clean energy for all is a specific goal (SDG 7). Energy is also fundamental to the achievement of other SDGs, such as healthcare, education, water and sanitation (SDGs 3, 4, 6), improved household incomes (SDG 8), more resilient settlements and infrastructure (SDGs 9, 11) and, of course, ending poverty (SDG 1). Yet, with all its actual and potential benefits for human activity, energy is also the world's primary source of greenhouse-gas (GHG) and air pollutant emissions. This makes it essential to reconcile energy objectives with the SDGs: taking action to combat climate change (SDG 13) and to reduce air pollution (SDG 3.9) are important energy-related environmental SDGs (Box 3.1).

The International Energy Agency (IEA) has, for many years, set energy-related objectives and tracked progress towards their achievement. Dominant among them has been improving energy security, an essential component of robust economic activity. Alongside measurement of progress towards this central goal, the *World Energy Outlook (WEO)* has also carefully monitored progress towards achieving energy-related social and environmental goals, such as universal access to modern energy services, reducing energy-related GHG emissions and minimising air pollution. The *WEO* has proposed energy sector pathways for the achievement of each of these goals individually, identifying key challenges and opportunities and providing insights to guide policy-makers:

- The *WEO* has analysed and tracked the number of people without access to modern energy services in developing countries for 15 years. It has analysed pathways to achieve universal modern energy access, through the Energy for All Case (first developed in 2003), in order to assist in the adoption of policies designed to end energy poverty.
- Each year, the *WEO* analyses the potential impact of all existing and newly announced policies on the evolution of energy-related CO_2 emissions. The New Policies Scenario serves as a benchmark that tracks progress towards the achievement of climate goals, among others. For nearly a decade, the *WEO* has additionally indicated, notably

through the 450 Scenario, energy sector pathways that are compatible with climate targets, identifying necessary areas for improvement in the evolution of the energy sector.

- The *WEO* has also assessed for many years the implications of energy sector activity for air pollution. In 2016, for the first time, the *WEO* also comprehensively assessed the implications for human health of the evolution of energy-related air pollution under the New Policies Scenario, presenting a feasible alternative in a Clean Air Scenario (IEA, 2016a).

Following past practice, the first part of this Chapter reviews energy and emissions trends, using the New Policies Scenario to track the probable impact of planned energy policy on the most relevant SDGs. In the second part, for the first time, we present a new scenario that, while maintaining the core objective of energy security, fully integrates the three most relevant SDGs (SDGs 3.9, 7 and 13). The objective of the new scenario is to specify an energy sector pathway that leads to a cleaner and more inclusive energy future, providing key insights into ways towards its achievement: the Sustainable Development Scenario.

Box 3.1 ▻ Sustainable Development Goals

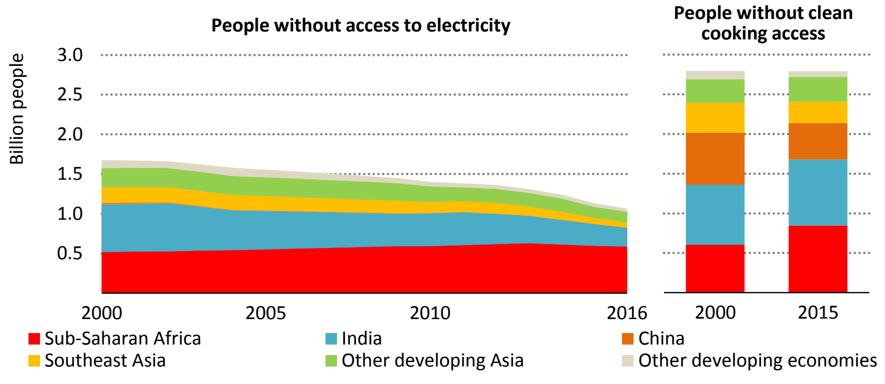
In September 2015, 193 countries, developing and developed countries alike, adopted the Sustainable Development Goals, known officially as the 2030 Agenda for Sustainable Development. The 17 new SDGs aim to end poverty, protect the planet and ensure peace and prosperity for all. For the first time, the development goals include a target focused specifically on ensuring access to affordable, reliable, sustainable and modern energy for all by 2030 (SDG 7), thus signalling an increase in awareness of the central significance of energy in achieving many of the other development goals and recognition of the interlinked nature of many of the other development goals. Beyond ensuring access to energy for all by 2030, SDG 7 has targets relating to an increased share of renewables in the energy mix (7.2), doubling the rate of improvement in energy efficiency (7.3), ensuring international co-operation on clean energy research and technology (7.A) and expanding and upgrading the infrastructure and technology required to provide modern and sustainable energy services (7.B).

Energy is also either explicitly or implicitly part of the other development goals. SDG 3 includes a target to reduce premature deaths from household air pollution (for which lack of access to clean cooking is a primary cause); SDG 11 includes targets on climate change adaptation and mitigation for cities and human settlements; SDG 12 has a target that aims at reducing harmful and inefficient fossil-fuel subsidies; and SDG 13 aims at taking urgent action to combat climate change. Action in the energy sector is also essential to the attainment of many of the other widely-drawn development goals, including high quality education (SDG 4), food production and security (SDG 2), economic growth and employment (SDG 8) and gender equality (SDG 5).

3.2 Recent trends and developments

Important progress towards the achievement of the energy-related SDGs has been made over recent years. In terms of electricity access, IEA analysis shows that the number of people estimated to be without access to electricity fell below 1.1 billion in 2016 and that the pace of providing access has accelerated (Figure 3.1). Yet, this means that around 14% of the world's population still lacks access to electricity. Of those so deprived, 97% are in sub-Saharan Africa and developing Asia, almost 85% in rural areas. Moreover, access to electricity alone does not necessarily mean access to an uninterrupted power supply; the number of people without access to reliable electricity is likely much higher.

Figure 3.1 ▷ People without access to electricity and clean cooking facilities



Access to electricity has improved in most regions, but gains have not kept up with population growth in sub-Saharan Africa

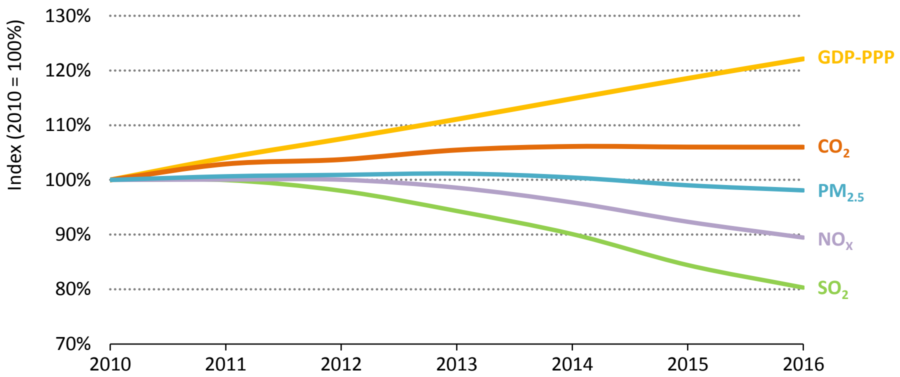
Clean cooking facilities represent another key part of modern energy services.[1] Despite growing awareness of the health risks and decades of effort targeting access to modern cooking, an estimated 2.8 billion people still have no access to clean cooking facilities, almost the same number as in 2000. For cooking, 2.5 billion people rely on the use of solid biomass, around 120 million people use kerosene and 170 million use coal. There has been progress in some areas, for example in China where the share of people relying on solid fuels for cooking has dropped from 52% in 2000 to 33% today. However, progress has been very slow in sub-Saharan Africa, where population growth has outstripped progress and 84% of the population still relies on solid biomass, coal or kerosene for cooking.

In terms of tackling climate change, SDG 13 and the Paris Agreement are closely related. SDG 13 recognises the United Nations Framework Convention on Climate Change (UNFCCC) as the primary forum for negotiating the international response to climate change, while

1. Clean cooking facilities are those considered safer, more efficient and more environmentally sustainable than traditional facilities using biomass (such as a three-stone fire). Clean cooking primarily refers to improved biomass cookstoves, biogas systems, liquefied petroleum gas stoves, ethanol and solar stoves (IEA, 2017a).

the Paris Agreement notes the importance of comprehensive sustainable development. The energy sector remains the largest contributor to greenhouse-gas (GHG) emissions: at least two-thirds of global GHG emissions are from the energy sector, the majority in the form of carbon dioxide (CO_2). But the last few years have shown important improvements in relation to CO_2 emissions. Despite an increase in global gross domestic product (GDP) of around 3% in 2016, our preliminary estimate of CO_2 emissions in 2016 shows that emissions stayed flat for a third straight year, at just above 32 gigatonnes (Gt). This indicates an important weakening of the link between economic growth and CO_2 emissions, driven by a combination of market dynamics, technological improvements and policy initiatives, reflected in the increased proportion of electricity being generated from renewables and energy efficiency improvements (themselves targeted in SDG 7.2 and 7.3). In 2016, lower CO_2 emissions in the United States and China offset the increase in other countries: US CO_2 emissions declined in part due to the increased use of shale gas and renewables, and in China, CO_2 emissions fell 1%, while the economy grew 6.7%.

Figure 3.2 ▷ Change in global economic output, energy-related CO_2 and air pollutant emissions



Recent years indicate a decoupling of economic growth and energy-related emissions

Notes: SO_2 = sulfur dioxide; NO_X = nitrogen oxides; $PM_{2.5}$ = fine particulate matter; PPP = purchasing power parity.

Sources: IEA analysis; International Institute for Applied Systems Analysis (IIASA).

Air pollution is another pressing environmental concern (SDG 3.9). More than 80% of the people living in urban areas where air quality is monitored are breathing air that does not comply with air quality standards set by the World Health Organization (WHO). The impacts on health are grave: air pollution ranks as the fourth-largest overall risk factor for human health worldwide, after high blood pressure, dietary risks and smoking. Each year, around 6 million people die prematurely from the impacts of air pollution: around 2.9 million premature deaths are linked to outdoor air pollution and around 2.8 million to household air pollution. Household air pollution is primarily linked to energy poverty and the traditional use of biomass for cooking (which underlines the SDG for universal access to modern energy), while outdoor pollution is closely linked to energy sector activity. Improvements have been registered: as in the case of CO_2 emissions, air pollutant emissions are decoupling from economic growth at a global level (Figure 3.2). The downward trend in SO_2 emissions, relative to the level in 2010, derives mainly from reduced emissions from coal use in the power and industry sectors, and lower sulfur content of transport fuels. The decline in coal use also triggered a reduction in nitrogen oxides (NO_X) emissions (from power) and a small drop in fine particulate matter ($PM_{2.5}$) emissions (from industry). Although these global improvements are significant, the effects of air pollution are very dependent on local conditions and concentrations.

Box 3.2 ▻ The Montreal Protocol and the Kigali Amendment

Dating from 1987, the Montreal Protocol aims to reduce ozone-depleting substances (ODS). It complements efforts to reduce GHG emissions, as many ODS have substantial global warming potential, and the UNFCCC does not cover gases that are controlled by the Montreal Protocol. In October 2016, after a seven-year consultation process, parties adopted the Kigali Amendment, which extends the Montreal Protocol to regulate hydrofluorocarbons (HFCs) in addition to conventional ODS. This is an important development because HFCs are potent greenhouse gases and their use was expected to grow rapidly as replacements for ODS regulated under the Montreal Protocol.

The initial primary focus of the Montreal Protocol was the phase-out of chlorofluorocarbons (CFCs). This led to rapid growth of hydrochlorofluorocarbons (HCFCs) as replacements, particularly in refrigeration. HCFCs were initially subject to a slower phase out under the Montreal Protocol as they have a reduced impact on the ozone layer. However, they are strong greenhouse gases and so, driven by climate change concerns, the parties to the Montreal Protocol decided in 2007 to advance the HCFC phase out schedule by ten years. The gradual and ongoing phase out has raised demand for yet another class of substitute gases, notably HFCs. HFCs are a preferred substitute due to their limited ozone depletion potential, but their effect on global warming is a major concern. While currently a small share of total GHG emissions, expected high growth rates could make HFCs a significant global warming factor, with a warming effect increased by as much as thirty-fold by 2050 (Velders et al., 2015).

The Kigali Amendment sets specific targets and timetables for reducing the production and consumption of HFCs by over 80% through the mid-2040s. The HFC phase-out begins in some countries in 2019, complementing efforts made by the parties to the UNFCCC to reduce their overall GHG emissions.

Climate stabilisation, clean air and energy access are now established components in modern energy policy, constraining and supplementing the basic objective of providing ample and secure energy supplies at reasonable end-user prices. Numerous new and updated policies have been adopted over the course of the past year in support of the achievement of these goals. For climate change, many of the new policies stem directly from the Nationally Determined Contributions (NDCs) that countries pledged under the Paris Agreement.

Important progress has also been made in another international arena, with a bearing on climate change: regulation of hydrofluorocarbons under the Montreal Protocol (Box 3.2). Clean air, too, is firmly on the policy agenda; further efforts to improve air quality have been undertaken in developed and developing countries alike. Table 3.1 summarises selected policy developments since the *WEO-2016* that are considered in this *Outlook*.

Table 3.1 ▷ Selected recent climate change and air pollution policy developments

Country/region	Selected recent policies
Australia	• Safeguard Mechanism requiring largest emitters (140 businesses) to keep emissions within individual baseline levels.
Canada	• Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, phase-out of traditional coal-fired electricity by 2030 (Nov 2016). • Economy-wide carbon pricing from CAD10 per tonne of CO_2 (tCO_2) in 2018, rising to CAD 50/tCO_2 in 2022.
Chile	• Carbon tax of $5 per tonne of CO_2 on emissions from large power plants and industrial emitters introduced in January 2017; includes a local air quality component.
China	• 13th Five-Year Plan (2016-20): includes energy, climate and air quality measures. • Energy Supply and Consumption Revolution Strategy, setting out overall targets and strategies of Chinese energy sector for 2016-30. • Carbon pricing: China national Emissions Trading Scheme rolling out from late 2017.
European Union	• Clean Energy Package (Nov 2016): energy efficiency (30% reduction below business-as-usual by 2030); power market design; capacity markets. • Carbon pricing: Proposal for EU Emissions Trading System (ETS) revision for Phase 4 is ongoing. • National Emission Ceilings Directive on local air pollutants for 2020 and 2030.
France	• Carbon tax on the use of fossil fuels not covered by the EU ETS, from EUR 22/tCO_2 in early 2016 to EUR 56/tCO_2 in 2020, rising to EUR 100/tCO_2 in 2030. • Announced ban on sales of gasoline and diesel cars from 2040.
Germany	• Climate Action Plan 2050, a mid-century strategy as called for by the Paris Agreement.
India	• Tax on coal, lignite and peat rising to INR 400/tonne. • Compliance with new standards to reduce power plant emissions of air pollutants PM_{10}, SO_2, NO_X under the Environment Protection Amendment Rules. • Consideration of target of 100% electric vehicle sales by 2030.
Japan	• Revised Act on Special Measures for Renewable Energy from 2017, including competitive tenders for large-scale solar PV. • Energy Efficiency Technology Strategy 2016.
Sweden	• Target to become carbon neutral by 2045.
United Kingdom	• Announced ban on sales of gasoline and diesel cars from 2040.
United States	• Intention at federal level to withdraw from the Paris Agreement. • US Executive Order on "Promoting Energy Independence and Economic Growth". • Review of the Clean Power Plan. • Potential delay to regulation of methane emissions from the oil and gas industry. • Re-opening of the Corporate Average Fuel Economy (CAFE) standards. • Carbon pricing: Revisions to the existing Cap-and-Trade Program in California and the Regional Greenhouse Gas Initiative (RGGI).

3.3 Trends in the New Policies Scenario

Economic and population growth, energy market and technology trends, and existing and new energy policies will all be critical determinants of the outcome in relation to energy-related SDGs. In the following section, we use the New Policies Scenario (which incorporates these factors to the extent they are known today) to examine the trend implicit in current and announced policies towards the realisation of reaching universal access to modern energy services by 2030, mitigating climate change and reducing energy-related air pollution.

3.3.1 Outlook for energy access

In the New Policies Scenario, an additional 610 million people gain access to electricity between 2016 and 2030, and another 90 million by 2040. This progress reflects increasingly ambitious and well-targeted national policies, as well as falling technology costs. For many countries, universal electricity access is achieved by 2030 or is close at hand. The overall access rate in developing countries increases from 82% today to 90% in 2030. Urbanisation is a strong factor driving electrification, as 98% of the population growth occurs in urban areas, which reach almost full electrification in 2030. But, overall, the world is not on track to achieve the universal electricity access target, as the projected number of additional connections per year in the New Policies Scenario, at 44 million, falls well short of the 92 million connections per year required to achieve full access by 2030. In particular, progress is only one-quarter of what is needed in sub-Saharan Africa (Figure 3.3). By 2030, 8% of the world population (or 675 million people) still lack access to electricity, mostly in rural areas, overwhelmingly in sub-Saharan Africa. By 2040, the number of people without electricity access actually grows to 711 million, as population growth in sub-Saharan Africa exceeds electrification efforts. Renewables play an important role in what is achieved: an estimated 200 million of the 700 million who gain access do so through on-grid renewables, and 255 million through decentralised renewables.

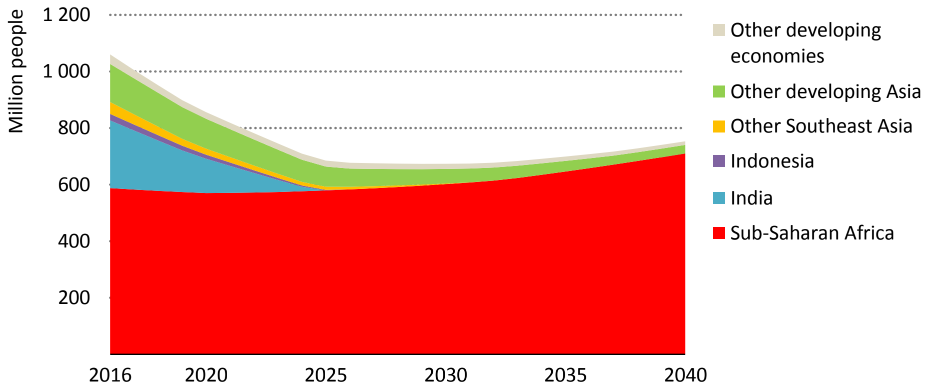
In Asia, the electrification rate reaches 99% in 2030, with almost universal electricity access by 2040. The population without electricity access falls dramatically by 2030, from 439 million in 2016 to 54 million and then to 30 million in 2040.[2] Much of this progress is attributable to efforts in India, where national policies have helped about half a billion people gain access to electricity since 2000.[3] India's political commitment is to achieve universal electrification by the early 2020s and, in the New Policies Scenario, successful continuation of current programmes helps to achieve this target, bringing electricity to an additional 250 million people. This achievement puts India among the countries that have achieved the largest number of connections in a relatively short period of time (IEA, 2017a). Indonesia achieves an electrification rate of 99% by 2025, and full electrification

2. DPR Korea and Papua New Guinea account for more than 80% of those who remain without electricity access in 2040.

3. These policies include notably the Deen Dayal Upadhyaya Gram Jyoti Yojana (DDUGJY) programme and its predecessor the Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) scheme.

before 2030, on the back of strong financial support from the government to expand its on-grid network. All other countries in Southeast Asia, with the exception of Cambodia, Laos PDR and Myanmar, reach universal access by 2030.[4] Afghanistan and Bangladesh, which rely on state-supported off-grid solar home systems, both reach universal access by the late 2020s.

Figure 3.3 ▹ Number of people without electricity access by region in the New Policies Scenario



Universal access to electricity remains elusive in most of sub-Saharan Africa as population growth outpaces electrification efforts; in Asia, most countries achieve full access

In sub-Saharan Africa as a whole, over 600 million people remain without access to electricity in 2030, as population growth outstrips electrification efforts. But there are some bright spots, especially in East Africa, where both Ethiopia and Kenya are on track to reach near-universal access by 2030. In these countries, over 5 million new connections are being added each year as efforts to roll-out grid infrastructure pick up and stand-alone systems are increasingly deployed in rural areas. South Africa is also on track to achieve near-universal access by 2030, on the back of its Integrated National Electrification Programme that combines grid extension and solar home system strategies. Ghana and Swaziland are also on track to achieve full electrification.[5] Latin America as a whole reaches near-universal access by 2030. Belize and Haiti (along with a few island nations) remain the outliers, though here, too, progress is made. In Haiti, almost 5 million people gain access by 2030, bringing the connection rate to 67%, twice the level of 2016. By 2040, the access rate is 85%.

4. *Southeast Asia Energy Outlook 2017*: *World Energy Outlook Special Report* looks in-depth at energy access for small islands and remote communities in Southeast Asia and is available for free download at: *www.iea.org/southeastasia*.

5. See the *Energy Access Outlook: from Poverty to Prosperity, World Energy Outlook Special Report* for an in-depth look at Africa. Available for free download at: *www.iea.org/energyaccess/*.

The picture for access to clean cooking facilities is more sombre. The global population relying on biomass, coal and kerosene for cooking falls slowly, from around 2.8 billion people in 2015 to just over 2.3 billion people in 2030 and 1.9 billion in 2040. Today, China and India together account for nearly half of the global population lacking access to clean cooking. However, in the New Policies Scenario, strong and persistent policy efforts in these countries to expand the use of liquefied petroleum gas (LPG) and reduce local air pollution, combined with rapid urbanisation, cut the total number of people without clean cooking facilities in these two countries to about 590 million by 2040, a reduction of around 760 million. In other parts of Asia, notably Indonesia, around 130 million people gain access to clean cooking by 2030 (210 million by 2040), bringing the number of people without access to just above 490 million in 2030 (430 million in 2040), compared with 560 million today. In sub-Saharan Africa, in contrast, efforts fail to keep pace with population growth. The number of people without access increases to over 900 million people by 2030. Over the *Outlook* period, a majority of those who gain access to clean cooking in urban areas do so primarily via LPG, while in rural areas almost half of those who do so via improved biomass cookstoves, with only 35% from LPG and the remainder from biogas.

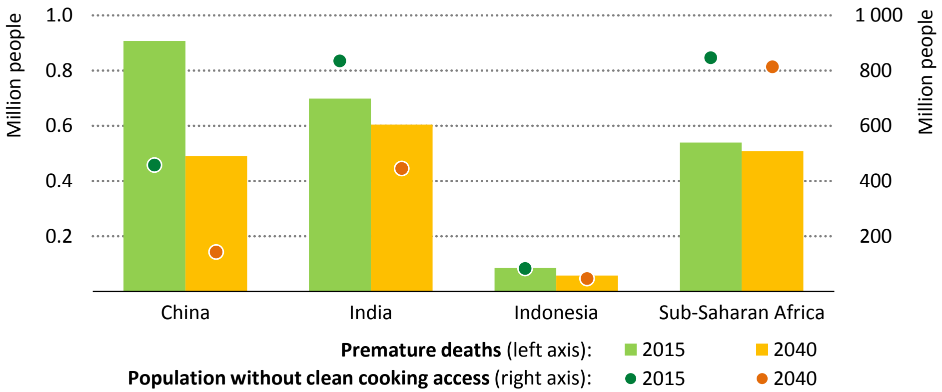
Reducing the health impacts from the use of solid biomass for cooking is a primary motivation for promoting modern fuels for cooking, as it is linked to 2.8 million premature deaths today, related to emissions of fine particulate matter ($PM_{2.5}$). Many alternatives exist, including improved or advanced biomass cookstoves that can have a chimney or a fan to aid combustion[6], or stoves fuelled by LPG, natural gas, biogas or solar energy. In the New Policies Scenario, the decreasing use of solid biomass for cooking reduces $PM_{2.5}$ emissions by around 15%, contributing to a decline of half a million in the number of people dying prematurely from household air pollution in developing countries by 2040.[7] The biggest part of this reduction is achieved in China (Figure 3.4). The reduction is less prominent in India. Although the reduction in the use of traditional stoves by 2040 is substantial in

6. "Improved" cookstoves have a higher efficiency or lower level of pollution than traditional stoves, through improvements such as a chimney or closed combustion chamber. "Advanced" stoves contain technical advances to increase combustion efficiency and lower pollutant emissions, such as micro-gasifiers. There is ambiguity as to whether improved stoves are "clean" as many models are associated with household air pollution at a level harmful to human health. For this reason, they are generally not considered to be clean cooking facilities in our analysis. However, improved cookstoves do form an important part of the provision of access in rural areas: these cookstoves are assumed to be the best available, and by 2030, they are assumed to reach the emissions performance of advanced cookstoves (IEA, 2017a).

7. The calculation of premature deaths from ambient (AAP) and household (HAP) air pollution follows the methodology used by the Global Burden of Disease 2013 study (Forouzanfar et al., 2015), calculating the fractions of deaths attributable to AAP and HAP by disease and age within total disease and age-specific deaths. Integrated exposure-response relationships are used to derive the relative risk at a given concentration of $PM_{2.5}$. These parameters have been updated since IEA (2016) and are now identical to those used in Forouzanfar et al. (2015) and WHO (2016). Projected age-specific baseline death rates are taken from the UN World Population Projections (UNDESA, 2011). It is assumed that age-specific contributions from individual diseases to total deaths within each age group remain constant. For HAP, it is assumed that users of traditional solid fuel-based cookstoves are exposed to indoor concentration levels of 300 microgrammes per cubic metre ($\mu g/m^3$) (within the range reported by Smith et al. (2014) and Balakrishnan et al. (2013), and users of clean solid fuel stoves to 70 $\mu g/m^3$.

India, premature deaths do not fall by a similar amount as the benefits are partially offset by strong population growth and the continued reliance of many people on biomass with improved cookstoves, which emit air pollution (albeit at a lower rate).

Figure 3.4 ▷ Premature deaths from household air pollution and population lacking access to clean cooking in the New Policies Scenario



Premature deaths from household air pollution are nearly half a million lower in 2040, relative to today, as access to clean cooking fuels increases

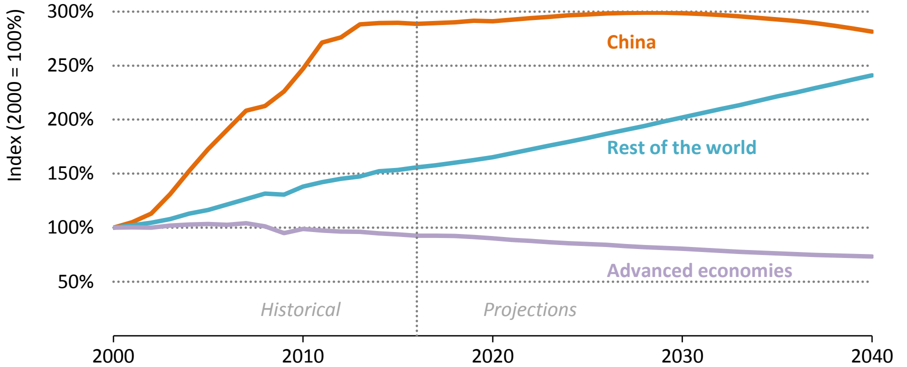
Note: Population without clean cooking access includes those relying on traditional use of biomass, coal and kerosene.

Sources: IEA; IIASA.

3.3.2 Outlook for energy-related GHG emissions

In the New Policies Scenario, energy and climate policies, and technology progress are not sufficient to deliver a global energy transition that achieves a peak in CO_2 emissions before 2040. Total energy- and process-related GHG emissions grow slowly in the New Policies Scenario as, despite the recent stall, the decline or flattening out of emissions in some countries is offset by growth in others (Figure 3.5). Even so, at 0.4% per year to 2040, CO_2 emissions growth in the New Policies Scenario is less than a quarter of the pace of growth since 2000. In 2040, energy-related CO_2 emissions are around 600 million tonnes (Mt) lower than projected in the *WEO-2016*, largely because of additional action in China and India, both of which have intensified plans for renewables and electric vehicles deployment. A global plateau is achieved in emissions from coal use, but this is offset by continued growth through 2040 in emissions from the use of oil (mostly in transport) and, particularly, natural gas which accounts for 80% of the net growth in CO_2 emissions (see Chapter 11). In 2040, total energy-related CO_2 emissions are nearly 36 Gt which, together with the emissions of other GHGs, set the world on course for a global mean temperature rise of roughly 2.7 degrees Celsius (°C) by 2100.

Figure 3.5 ▷ **Three speeds of CO_2 emissions growth in the New Policies Scenario**



Growth in energy-related CO_2 emissions varies by country and region; the slowdown or decline in some countries is offset by growth in others

Methane is a more potent greenhouse gas than CO_2 and, at 10% of the total in CO_2-equivalent terms, the second-largest source of energy-related GHG emissions.[8] The majority of energy-related methane emissions arise from the production and distribution of oil and natural gas, and from coal mining, with a smaller contribution coming from bioenergy and the incomplete combustion of natural gas in some end-use sectors. In the New Policies Scenario, methane emissions from these sources fall, despite an increase of 45% overall in natural gas supplies between 2016 and 2040. A number of opportunities exist to avoid methane releases in a cost-effective manner using technologies that will pay for themselves through the sale of the captured methane (see Chapter 10).

Nitrous oxide (N_2O) is the third-largest greenhouse gas and grows fastest among energy-related emissions in the New Policies Scenario. N_2O stays in the atmosphere longer and has a global warming potential around three hundred-times greater than CO_2 on a 100-year timeframe. While N_2O accounts for less than 1% of energy-related GHG emissions, emissions due to the production of biofuels – led by Brazil, European Union and United States – increases the total by more than one-quarter, although this increase is partly offset by CO_2 savings due to biofuels displacing fossil fuels.

Regional trends

In the New Policies Scenario, many countries make progress towards the achievement of their NDCs. In *China*, the targets of the 13th Five-Year Plan (2016-2020) on energy development, including the start of the roll-out of national emissions trading, have been supplemented by the longer term Energy Supply and Consumption Revolution Strategy

8. A factor of 30 is used here to convert methane to CO_2 equivalent based upon the 100-year global warming potential (GWP) of methane. See Chapter 10 for some caveats regarding the use of the GWP.

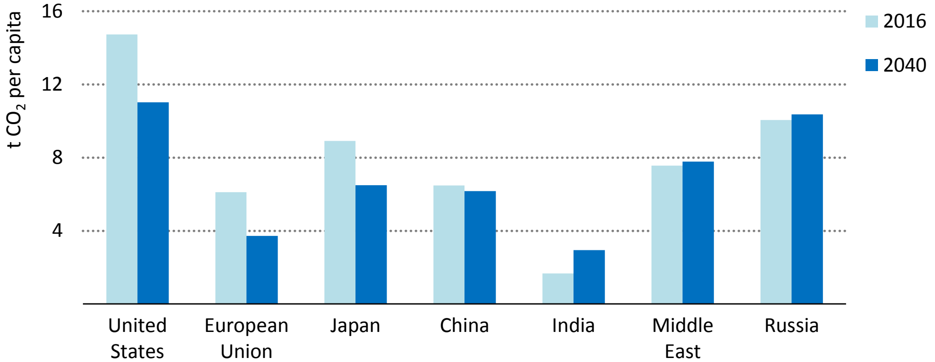
(2016-30). The reinforced policy objectives, combined with a rapid global decline in the cost of low-carbon technologies, lead to China's energy-related CO_2 emissions peaking in 2028 in the New Policies Scenario, two years before the target year of its NDC (see Chapter 13). While China was responsible for almost two-thirds of global CO_2 emissions growth from 2000-16, it accounts for only 11% of global growth from 2016-30. By 2040, Chinese emissions are 4% lower than in 2016 (Figure 3.5). The power and transport sectors are important drivers of emissions. Despite a strong projected uptake of renewables, continued use of coal for power generation prevents that sector's emissions from peaking until the early 2030s, and transport sector emissions continue to grow through to 2040. Emissions from the industry sector continue to decline in the New Policies Scenario, due in part to a shift towards high-tech manufacturing. However, delay in restructuring China's heavy industrial sectors, notably iron and steel and cement, could add around 5 Gt of CO_2 emissions through 2040 to the trend projected, equivalent to about 14 months of CO_2 emissions from China's current power generation fleet (see Chapter 13).

In *India*, energy-related CO_2 emissions more than double by 2040 in the New Policies Scenario, relative to today. But emissions growth in India is slower – 410 Mt less CO_2 emitted from fossil fuels in 2040 – than projected in the *WEO-2016*. The reason is that India is increasingly committed to a lower carbon electricity supply, as further indicated in its draft National Energy Policy (released in July 2017) and the National Electricity Plan. The latter includes a strong renewables commitment, with a target of 100 GW of solar photovoltaic (PV) by 2022 set against the backdrop of a near-doubling of PV installations in each of the last two years, and a reduction in the number of planned new coal-fired plants. Fuel taxes have also increased, with taxes on coal, lignite and peat doubling in the 2016-17 budget to Indian rupee (INR) 400/tonne (about $6/tonne). Practically all emissions savings in India relative to the *WEO-2016* stem from the power sector (see Chapter 6). Emissions keep rising in other sectors, in particular in industry and transport. Development of the industrial sector is an integral part of the "Make in India" initiative, boosting economic growth and emissions growth. In the transport sector, the government has announced a push towards 100% electric vehicle sales in 2030, meaning electric cars progressively make inroads into the total vehicle fleet in the New Policies Scenario. New fuel-efficiency standards for heavy-duty vehicles will come into force in 2018, with more stringent standards to follow in 2021. In 2040, India's annual emissions per capita, at around 3 tonnes of CO_2, are still much lower than those of other major economies (less than one-third of those of the United States and Russia).

The *European Union* (EU) appears on course to achieve its NDC commitment, supported by the 2016 "Clean Energy for All" package, which includes new proposals for renewables objectives and a proposed energy efficiency target of a 30% reduction below business-as-usual by 2030. In the New Policies Scenario, EU emissions from fossil-fuel combustion fall by 2% per year to 2040, a continuation of the average rate of decline since 2003. Around 45% of emissions savings come from the power sector, reflecting, among other measures, end-use efficiency measures, renewables targets and the EU Emissions Trading System (ETS). The proposed plan for Phase 4 of the ETS (post-2020) is to increase the annual rate of reduction of the overall cap from 1.7% to 2.2-2.4%, with a view to achieving a

43% emissions reduction in the covered sectors by 2030, relative to 2005 levels. In the New Policies Scenario, road transport makes the second-largest contribution to emissions savings, accounting for around one-quarter of the total, mostly due to cars, for which fuel-economy standards are already in place. The share of diesel cars falls significantly in the New Policies Scenario, from 46% to 31%. The European Union also aims to propose new fuel-efficiency standards for heavy-duty vehicles in early 2018. Depending on their stringency, projected emissions savings from transport could turn out to be higher.

Figure 3.6 ▷ CO_2 emissions per capita for selected regions in the New Policies Scenario



CO_2 emissions per capita vary significantly between regions, falling in advanced economies and China and nearly doubling in India

In the *United States*, the New Policies Scenario takes into account the declared intention to replace the Clean Power Plan, but other US market and policy dynamics for the power sector remain largely unchanged. For example, federal tax credits for renewables-based electricity investments are assumed to remain in place through 2022, and natural gas is expected to hold a competitive advantage over coal for some time to come. In the New Policies Scenario, as a result, CO_2 emissions in the US power sector decline by a further 10% between 2016 and 2040, or 34% compared to their 2005 peak. Greater uncertainty resides in the US transport sector, as the new standards arising from a mid-term evaluation of the Corporate Average Fuel Economy (CAFE) standards for light-duty vehicles will be determined over the coming year, and uncertainty prevails over the implementation of Phase II standards for heavy-duty vehicles. There is also some uncertainty around regulation of methane emissions from the oil and gas industry, as a proposed two-year delay in implementing new performance standards limiting methane emissions was struck down by a federal appeals court in July 2017. Overall, US CO_2 emissions from oil decline by one-third by 2040, a higher rate of decline than the 13% drop in emissions from coal. However, at 4.2 Gt CO_2 in 2040, total emissions are 7% higher than projected in last year's New Policies Scenario and the United States remains the highest per-capita emitter through to 2040 (Figure 3.6).

SPOTLIGHT

Which sub-national initiatives can help deliver the low-carbon transition?

Action to combat climate change is being taken by a wide range of actors, in addition to national governments. For example, 177 sub-national jurisdictions have joined the "Under 2 Coalition", with a collective aim of limiting GHG emissions to less than 2 tonnes per capita. Additionally, at the city level, over 90 of the world's largest cities, representing over 650 million people, are collaborating in the C40 initiative, which aims to reduce average per capita emissions across those cities from over 5 t CO_2-eq (tonne of carbon dioxide equivalent) today to 2.9 t CO_2-eq by 2030 (C40 and Arup, 2016). The European Covenant of Mayors, launched in 2008, was made global in early 2017 and counts over 6 000 submitted action plans. Companies increasingly view climate policy as a contribution to longer term investment certainty, while renewable energy and energy efficiency help insulate them from fossil-fuel price volatility. Of a sample of 1 089 global companies, accounting for roughly 12% of global GHG emissions, 85% have already set mitigation targets, adding up to a reduction of 1 Gt CO_2-eq by 2030 below current emission levels (CDP, 2016). Another survey revealed 1 200 companies that are currently using an internal price on carbon or plan to do so within the next two years (World Bank, 2016).[9] A small selection of such corporate targets is presented in Table 3.2. The Non-State Actor Zone for Climate Actions Platform, which tracks action to address climate change by cities, regions, businesses and investors, currently registers over 12 500 pledges. Accounting for the effects of non-state climate action is not easy, the difficulties including possible double-counting with national targets (UNEP, 2016) and dealing with boundary issues (such as power plants outside city limits). Nevertheless our analysis of pledged sub-national targets suggest that these alone could help reduce emissions by nearly 2 Gt CO_2-eq in 2030.

The United States is one of the global powerhouses of such sub-national action. One declaration of continued support for climate efforts is "We Are All In", signed by nine states, and more than 200 cities and counties, 1 700 companies and 300 universities. Another example is the United States Climate Alliance signed by 14 state governors and Puerto Rico, representing about 116 million people. There is a vast amount of state-level action, including California's Cap-and-Trade Program, the Regional Greenhouse Gas Initiative (RGGI) for northeast states, Renewable Portfolio Standards adopted by 30 states as of early 2017, renewable energy goals set by eight states, and Energy Efficiency Resource Standards adopted by 26 states as of early 2017 (ACEEE, 2017). We estimate that if all targets set by sub-national actors in the United States were achieved, their GHG emissions would fall by nearly 900 Mt by 2025, relative to 2005.

9. Note that the sample is selected based on self-reporting and therefore likely skewed towards companies with higher commitment to climate issues.

Table 3.2 ▷ Selected climate and clean energy targets from sub-national actors including cities, states and companies

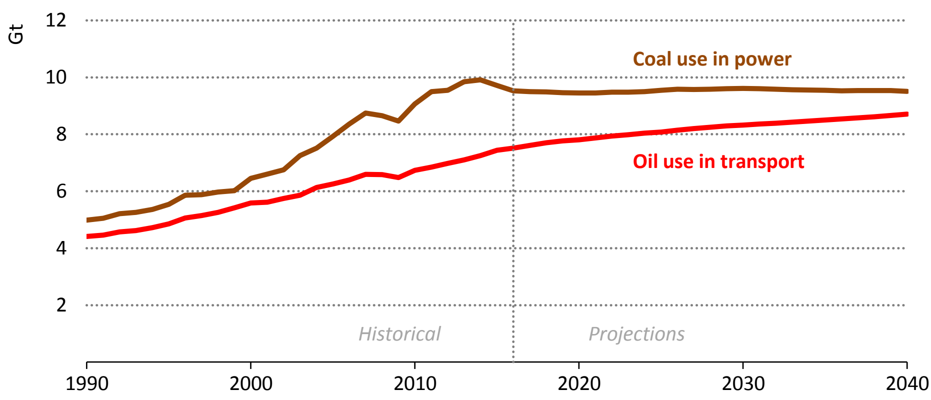
Cities or regions	Emissions target/clean energy target	Recent GHG emissions estimate (Mt CO_2-eq)
Paris (France)	-25% by 2020 relative to 2004.	20
Tokyo (Japan)	-30% by 2030 relative to 2000.	70
Copenhagen (Denmark)	Carbon neutral by 2025 (base year used here is 2014).	1.7
Oslo (Norway)	-50% by 2020 relative to 1990; carbon neutral by 2050.	2.6
Vancouver (Canada)	-80% by 2050 relative to 2007; 100% renewables before 2050.	2.6
Boston (US)	-25% by 2020 relative to 2005 and 80% by 2050.	6
New York City (US)	-30% by 2030 relative to 2006.	52
Johannesburg (South Africa)	-20% for municipal transport; -30% for commercial and industrial; -10% for residential by 2020 relative to 2007.	25
Cape Town (South Africa)	-13% by 2020 relative to 2012 business-as-usual.	21
North Rhine-Westphalia (Germany)	-80% by 2050 relative to 1990 levels.	300
Australian Capital Territory	-40% by 2020 relative to 1990.	4
Jalisco State (Mexico)	-30% by 2030 relative to 2010; -50% by 2050.	42
California (US)	-80% by 2050 relative to 1990.	460
Washington (US)	-25% by 2035 relative to 1900; -50% by 2050.	92
Hawaii (US)	Reduce emissions to 1990 levels by 2020.	20
Amazonas (Brazil)	Halve loss of natural forests by 2020; end forest loss by 2030.	-
Saõ Paulo State (Brazil)	-20% by 2020 relative to 2005.	89
Rio State (Brazil)	-30% by 2030 relative to 2005.	67
Corporate	**Emissions target/other target**	
Google (US)	100% of electricity sourcing from renewables by 2017.	
Walmart (US)	-1 Gt CO_2-eq from total supply chain by 2030 (aggregate).	
General Motors (US)	-20% in emissions intensity of operations per vehicle produced by 2020.	
NRG Energy (US)	-50% CO_2 emissions by 2030 relative to 2014; -90% by 2050.	
Nestle (US)	Internal carbon price of $15.47/t CO_2.	
Mahindra Sanyo Special Steel (India)	-20% in electricity consumption; -70% in oil consumption; -50% in water consumption by 2021 relative to 2013.	
Ambuja Cements (India)	-28% in emissions intensity per tonne of product by 2020 relative to 1990.	
Essar Oil (India)	Internal carbon price of $15/t CO_2.	
Tesco (UK)	-60% by 2025 relative to 2015 levels for Scope 1 and 2 emissions.	
Enel (Italy)	-25% CO_2 emissions by 2020 relative to 2007, carbon neutral by 2050.	
Energias de Portugal	-55% for Scope 1 and 2 emissions; -25% for scope 3 by 2030 relative to 2015.	

Notes: Data sources include C40, The Climate Group, the DTU Cities & Regions Pipeline and individual sources. Scope 1 emissions refer to direct GHG emissions; Scope 2 are indirect emissions from consumption of electricity, heat or steam; Scope 3 emissions are all other indirect emissions, including supply-chain emissions (following definitions in the GHG Protocol).

Sectoral trends

Although significant steps are being widely taken to reduce global energy-related CO_2 emissions growth, the extent of progress varies by sector. The main driver of CO_2 emissions growth over 2000-2016 has been the use of coal for power generation. The power sector is a principal focus of climate-related policies today around the world. In the New Policies Scenario, power sector policies serve to keep emissions growth globally basically flat, despite an increase of electricity generation by nearly 40% (see Chapter 6). New additions of coal-fired power plants are dwarfed by wind and solar capacity additions of more than 70 GW per year through to 2040. The slight increase in power sector emissions through 2040 is attributable to rising natural gas-fired power generation, which helps to reduce the emissions intensity of power generation. The average CO_2 intensity of the power fleet today is around 500 grammes of CO_2 per kilowatt-hour (g CO_2/kWh), while that of all new capacity entering operation in 2016 is around 450 g CO_2/kWh. In the New Policies Scenario, the suite of current and planned policies and continued rapid technological progress bring down the average CO_2 intensity of power generation in 2040 to 325 g CO_2/kWh, lower than the level of a highly efficient new gas plant. This change occurs despite the downward revision of nuclear power projections in this *Outlook,* due to announcements in Korea and France to accelerate nuclear retirements and the bankruptcy of Westinghouse, a major global supplier (Chapter 6). Even so, the power sector remains the largest contributor to energy-related CO_2 emissions in the New Policies Scenario.

Figure 3.7 ▷ CO_2 emissions from oil use in transport and coal use in power generation in the New Policies Scenario



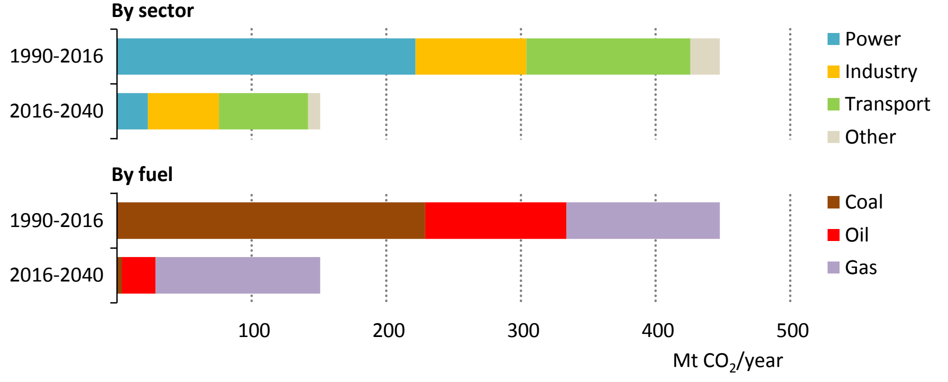
CO_2 emissions from oil use in transport approach emissions from combusting coal as the power sector decarbonises

Progress towards decarbonisation is slower in other sectors. In transport, the second-largest source of energy-related CO_2 emissions today, dependence on oil is beginning to weaken, but only slowly. By 2040, 14% of all cars on the road are projected in the New Policies Scenario to be electric (with over 70 million sales in 2040), up from 0.2% today (see

Chapter 2). Together with the application of fuel-economy standards and the expansion of biofuels, this leads to oil demand from passenger cars peaking before 2030, even though the number of cars doubles. But oil use in road freight, air and shipping keeps rising. Road freight, in particular, emerges as a major source of oil demand and therefore emissions growth, as only five countries currently have fuel-economy standards for new trucks, compared with around 40 countries for new cars (IEA, 2017b). The continued rise in oil demand for transport to 2040 means that CO_2 emissions from transport approach the level at which emissions from coal use in the power sector plateau, challenging a hierarchy that has persisted since coal-fired power plants became dominant several decades ago (Figure 3.7) (see Chapter 4).

In the industry sector, in the New Policies Scenario, demand for industrial products continues to rise and existing and planned policies (which typically take the form of carbon prices or efficiency standards) are insufficiently strong to offset the effects of that production growth. The energy intensity of industrial production falls by over a quarter to 2040, but industrial emissions increase by almost one quarter, meaning industry remains a key contributor to emissions growth to 2040 (Figure 3.8). Direct emissions from energy use in buildings account for less than 10% of energy-related CO_2 emissions, meaning that the emissions intensity per unit of energy used in the buildings sector is two-to-three-times lower than that of other sectors. But buildings are also responsible for around half of global electricity demand and for district heating and cooling. Indirect emissions from these sources, at 5.5 Gt CO_2, are almost twice as high as the direct emissions from buildings. In the New Policies Scenario, direct emissions from the buildings sector remain broadly stable, despite a 60% growth in residential floor area to 2040. But indirect emissions rise by 12% and keep the emissions intensity of the buildings sector well above 2 tonnes of CO_2 per tonne of oil equivalent (t CO_2/toe) by 2040.

Figure 3.8 ▷ Annual CO_2 emissions growth by sector and by fuel in the New Policies Scenario



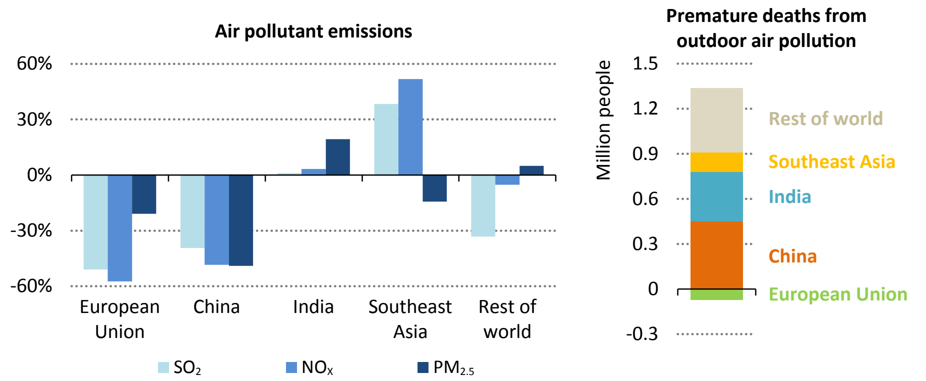
As the power sector decarbonises, transport becomes the main driver of CO_2 emissions growth; among fuels, natural gas takes the lead as it expands its share in the energy mix

3

3.3.3 Outlook for energy-related air pollution

Numerous policies are in place to reduce energy-related air pollution, including policies both to reduce emissions (such as through setting standards that can be met by post-combustion treatment through scrubbers, filters or others) and to avoid them altogether (such as by supporting the energy transition to low-emitting fuels). The combined effect of these policies in the New Policies Scenario is that emissions of all air pollutants (including process-related emissions) decrease despite an increase in global primary energy demand of about 30% to 2040.[10] SO_2 emissions decline by 25%, NO_X emissions by about 14% and $PM_{2.5}$ emissions by about 7% in 2040, relative to 2015. Although these projections reflect positively on current policy efforts overall, the trends differ substantially by region and level of economic development. No country or region considered individually in our analysis completely eliminates energy-related air pollution emissions. Indeed, in the New Policies Scenario, in 2040 significant populations still live with levels of $PM_{2.5}$ concentrations exceeding WHO guidelines (see section 3.4). Moreover, the health impacts of air pollution are complex, depending on local concentrations, the age of the population and other factors, such as whether exposure is acute or chronic. Globally, in 2040, around 4.2 million people die prematurely from outdoor air pollution, more than 40% more than today (Figure 3.9).

Figure 3.9 ▷ Change in air pollutants emissions by region and premature deaths from outdoor air pollution in the New Policies Scenario, 2015-2040



Emissions of the main air pollutants fall in many regions, but premature deaths keep rising

Sources: IEA analysis; IIASA.

10. The analysis is carried out in collaboration with the International Institute of Applied Systems Analysis (IIASA). The IEA's World Energy Model (WEM) and IIASA's Greenhouse Gas - Air pollution Interactions and Synergies (GAINS) model are coupled to derive insights into air pollution trends on the basis of *WEO* projections for energy sector developments. For details, see (IEA, 2016a). For the first time, Annex A of *WEO-2017* includes data on global emissions of pollutants by energy sector and fuel (Table A.3).

Regional trends

Emissions of most major air pollutants are already in decline in many advanced economies and this trend continues in the New Policies Scenario, as total energy demand falls (reflecting increasing energy efficiency), the use of low-carbon alternatives increases and more stringent post-combustion control regulations take effect. In the *United States*, the use of coal falls by more than 10% by 2040 and that of oil by one-quarter, while low-carbon energy sources (including biomass) grow and expand their share in the energy mix to 24% in 2040 (despite the assumed replacement of the Clean Power Plan). Combined with air pollution policies, the net effect is a reduction of the emissions of all major pollutants: SO_2 and NO_X emissions drop by around 50% in 2040, while $PM_{2.5}$ emissions decline by more than one-third.

In the *European Union*, the new National Emission Ceilings Directive sets air pollutant targets for 2020 and 2030. These targets support a decline in SO_2 emissions by more than 50% through 2040, mainly driven by the power sector, while NO_X emissions fall by around 55%, mainly in transport. $PM_{2.5}$ emissions fall by more than 20%, although the steady decline of transport emissions is offset by more modest declines in emissions from biomass in the residential and power sectors, and by stable emissions in the industry sector.

In *Japan*, energy regulations to reduce air pollution and to increase energy efficiency lead to the decline of SO_2 and $PM_{2.5}$ emissions by more than one-third to 2040, and of NO_X by 45%.

In developing countries, the situation is varied. *China*'s 13th Five-Year Plan (2016-2020) mandates an increase in days of good or excellent air quality to over 80%, and provides a $PM_{2.5}$ intensity reduction target, as well as emissions targets for SO_2 (15%) and NO_X (15%). Increasingly stringent emissions standards are being introduced (the latest being discussed is China 6a and 6b for passenger cars in 2020 and 2023), and a significant effort is being made to diversify the energy mix in favour of low-emitting fuels (see Chapter 13). As a result, SO_2 emissions fall by around 40% in 2040, relative to 2015, and NO_X and $PM_{2.5}$ fall by about 50%. Despite this progress, air pollution remains a major issue in China as urbanisation increases and the population ages and becomes more vulnerable to the impacts of air pollution. As a result, the number of people dying prematurely from outdoor air pollution increases from just below 1 million today to 1.4 million in 2040, despite significant improvements in air quality.

In *India*, a strong push towards the use of renewables contributes to avoiding air pollutant emissions growth in the power sector, but the implementation of new standards introduced under the Environmental Protection Amendment Rules is essential to reduce such emissions from existing and planned coal-fired power plants. Implementation has so far been slow, due to cost-driven delays in upgrading the filters and scrubbers at existing plants. In transport, although electric vehicles make inroads in the New Policies Scenario, stringent fuel-efficiency standards for vehicles are essential to limit emissions. Bharat Stage IV air pollutant emission norms have been in force across India since April 2017 despite legal challenges from automobile manufacturers. A jump to Stage VI norms is expected in 2020. Overall, air pollutant emissions continue to rise slowly, while energy demand more than doubles to 2040. $PM_{2.5}$ emissions rise most strongly, almost 20% higher in 2040 than today, due to increased emissions from industry, even though emissions from the buildings sector are lower due to reduced dependence on traditional use of biomass for cooking. NO_X and SO_2 emissions remain broadly at today's level. The result is a death toll that keeps rising: by 2040, 0.9 million die prematurely each year from outdoor air pollution in India, compared with 0.5 million today.

In *Southeast Asia*, energy demand grows rapidly, by 2.1% per year through 2040, and is accompanied by a doubling of coal consumption and a rise in oil use by around 40%. The stringency of air pollution regulation varies across the region and enforcement remains fairly weak. Overall, SO_2 (almost 40% higher in 2040, relative to today) and NO_X emissions (more than 50%) grow significantly; $PM_{2.5}$ emissions decrease modestly (-15%) as clean cooking facilities are increasingly deployed. Air pollution remains a serious health concern: in Indonesia, for example, 0.14 million die prematurely from air pollution in 2040, compared with 0.1 million today.

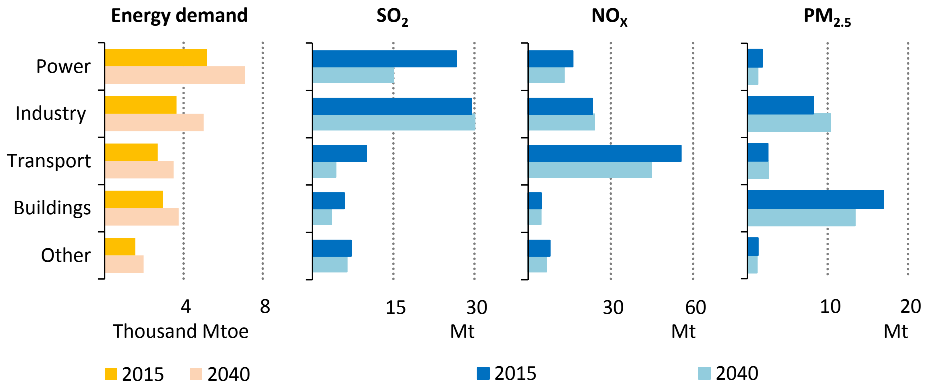
In *sub-Saharan Africa*, the population grows by three-quarters to 2040, increasing energy demand by about two-thirds beyond today's level. Policies to address air pollution are practically absent on the continent, with a few exceptions such as in South Africa. Consequently, NO_X emissions rise by 40% to 2040 as incomes rise and demand for mobility develops. $PM_{2.5}$ emissions grow by 18%, mostly from the continued use of inefficient cookstoves. SO_2 emissions decline by one-quarter in 2040, driven mostly by power sector regulation in South Africa.

Sectoral trends

Efforts to reduce air pollution span all energy sectors. As in the case of CO_2, policy efforts successfully curb emissions growth in the power sector in the New Policies Scenario. With the strong energy policy focus on renewables in particular, and with additional policies to increase air pollution control and monitoring in many countries, power sector emissions of all air pollutants fall, despite a rise in electricity demand. Today, at a global level, air pollutant emissions from power generation mostly relate to the use of coal; the exception is SO_2, to which oil also makes an important contribution, for example in the Middle East. In 2040, in the New Policies Scenario, SO_2 emissions from the power sector are globally more than 40% lower than today, as the use of oil for power generation declines. NO_X emissions decline by 20% and $PM_{2.5}$ emissions fall by around one-third (Figure 3.10).

Unlike for CO_2 emissions, policy efforts in transport also successfully reduce emissions of NO_X and SO_2. Transport-related SO_2 emissions stem mostly from the use of heavy fuel oil in shipping and they fall by nearly 60% following new regulations by the International Maritime Organisation. NO_X emissions, which come mostly from road vehicles, fall by nearly 20% to 2040, despite a doubling of the vehicle fleet. One reason is the increasing uptake of electric cars, which rises to 280 million by 2040 (from 2 million today); the other reason is that vehicle emissions standards in the major global car and truck markets are becoming increasingly stringent. $PM_{2.5}$ emissions from transport essentially stay flat, as improvements in emissions standards for trucks are offset by the overall increase in the global car and truck fleet (pushing up $PM_{2.5}$ emissions associated with abrasion, brakes and tyres).

Figure 3.10 ▷ Global energy demand and air pollutant emissions by sector in the New Policies Scenario



Air pollutant emissions continue to decouple from energy demand growth, although the extent differs by pollutant and sector

Note: Mtoe = million tonnes of oil equivalent; Mt = million tonnes.

Sources: IEA analysis; IIASA.

The industry sector is the only one in which, at a global level, there is no reduction in any of the main air pollutants. Although regulations, often stringent, are in place in many countries, the rise in industrial production and the lack of success in decarbonising fuel use in the New Policies Scenario (which assumes existing and announced policies) means that industry-related SO_2 emissions grow slightly by 2% through 2040, NO_X emissions by 3% and $PM_{2.5}$ emissions by around 25%. The primary contributors to industrial $PM_{2.5}$ emissions are process-related emissions from iron and steel production.

The buildings sector is the main contributor to $PM_{2.5}$ emissions at a global level, largely as a result of the traditional use of biomass for cooking in developing countries. These emissions fall significantly as an increasing number of people get access to other means of cooking, although they still constitute the largest source of $PM_{2.5}$ emissions in 2040 in the New Policies Scenario. SO_2 emissions fall by 40% to 2040, also driven by increasing access to clean cooking facilities. NO_X emissions fall only modestly, as increasing emissions in the services sector partially offset the global decline in the residential sector.

3.4 The Sustainable Development Scenario

3.4.1 Background

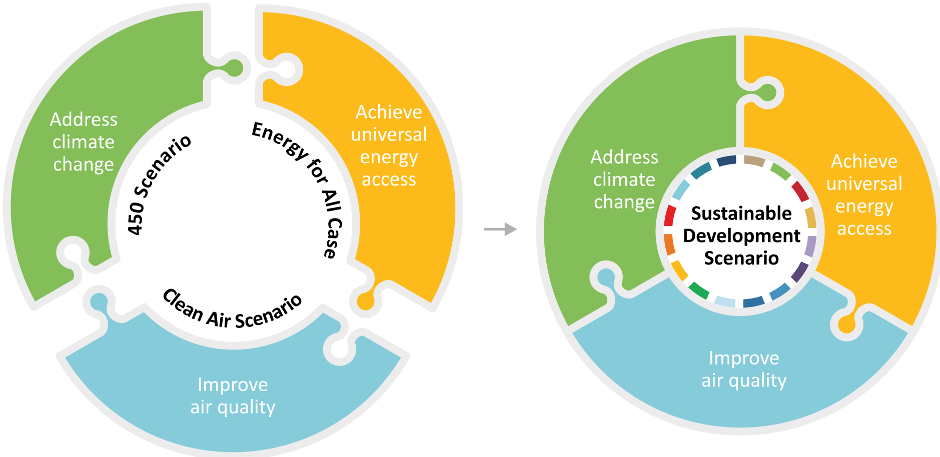
The *World Energy Outlook* has for a long time incorporated alternative scenarios, designed to examine in detail the energy sector pathways that are associated with different intensities of policy activity. Increasingly, scenarios have been presented that are normative in nature, that is they work back from stated goals to establish what needs to be done in the energy sector to achieve the objectives. Including this type of approach enables an assessment to be made – by country, sector, and fuel – of the gap between where existing policies are leading us and where we might desire to be, and to analyse the means in the energy sector by which the gap might be bridged.

Introduced in the *WEO-2008*, the 450 Scenario has offered for nearly a decade such quantitative insights for policy-makers, industry and investors, highlighting the policy, technology development and investments required to meet a global 2 °C climate change target, and quantifying the additional effort needed. Other scenarios have also been developed to offer insights into alternative goals such as the minimisation of air pollution (*WEO* Clean Air Scenario [IEA, 2016a]) or Energy for All (originally developed for the *WEO-2003*). With a focus on particular policy outcomes, these scenarios sought to provide insights directed to the interests of the key ministries in charge of particular aspects of policy (energy, environment and development), while also assessing the impacts for the portfolios of others.

This approach of treating individual policy goals in isolation has limitations. The 17 SDGs of the 2030 Agenda for Sustainable Development formally came into force in 2016. The SDGs, for the first time, integrated multiple policy objectives, recognising, for example, that ending poverty must go hand-in-hand with strategies that build economic growth and address a range of social needs, while also tackling climate change and strengthening environmental protection. Just a few months later, in November 2016, the Paris Agreement entered into force, and around 170 countries have now ratified it. It builds on the NDCs offered by those countries, primarily to address climate change, though many countries put their contribution in the context of other policy goals, including ending poverty or reducing air pollution.

There is a clear need to shift towards integrated policy-making. The first objective of international energy policy-making has, since the days of oil disruption, been to ensure that energy is amply and securely available, at a reasonable price, to meet the needs of sustained economic development. But, for many years, it has also been clear that pursuit of energy security has to be accompanied by social and environmental considerations. Energy supply obtained at unacceptable social or environmental cost is not secure or sustainable. Increasingly, energy sector development pathways are required to move hand-in-hand with economic development and prosperity, social priorities and environmental needs, supporting policy objectives in all those areas. Focussing on a specific goal in isolation might risk a lock-in of energy sector pathways that impede the achievement of other goals, or at least makes their attainment more expensive or more difficult.

Figure 3.11 ▷ Connecting individual policy targets in the Sustainable Development Scenario



The Sustainable Development Scenario integrates the main energy-related SDG targets

This *World Energy Outlook-2017* embraces this integrated approach through the development of a new Sustainable Development Scenario that aims to provide an energy sector pathway that combines the fundamentals of sectoral energy policy with three closely associated but distinct policy objectives (Figure 3.11), These aims are: to ensure universal access to affordable, reliable, sustainable and modern energy services by 2030 (SDG 7); to substantially reduce the air pollution which causes deaths and illness (SDG 3.9); and to take effective action to combat climate change (SDG 13). The objective is to lay out an integrated least-cost strategy for the achievement of these important policy objectives, alongside energy security, in order to show how the respective objectives can be reconciled, dealing with potentially conflicting priorities, so as to realise mutually-supportive benefits. Examples can readily be drawn. First and foremost, lack of access to modern energy is the most extreme form of energy insecurity, which makes the achievement of universal access by 2030 a core social and energy objective. Similarly, the Sustainable Development Scenario provides a significant increase in the use of domestic resources, such as renewables and energy efficiency, contributing to energy security through declining fossil-fuel use (notably for importing countries), while making an essential contribution to climate stability. In contrast to dedicated climate scenarios, the Sustainable Development Scenario puts stronger emphasis on decentralised low-carbon technologies as a means to achieve multiple policy objectives (Box 3.3).

3.4.2 Methodology and key assumptions

Many policies that are implicit in or explicit to the achievement of the energy-related SDGs are already in place or planned today. Relevant existing or planned policies are already embodied in the New Policies Scenario, a scenario consistent with the course on which governments appear at present to be embarked. The current level of ambition, however, is not sufficient for the achievement of the specified SDGs, which is illustrated by three main results from the New Policies Scenario:

- By 2030, there are still 675 million people who have no access to electricity, and 2.3 billion who do not have access to clean cooking facilities. The latter is linked to 2.5 million premature deaths from the impact of household air pollution.
- If no further action is taken beyond the energy policies and measures that have already been implemented or announced, then the world is not on track to achieve the temperature goals of the Paris Agreement.
- Despite progress in reducing air pollution in many countries, there are still 4.2 million premature deaths linked to outdoor air pollution in 2040.

Achievement of all three goals **as an integrated part of energy policy** is the intention of the Sustainable Development Scenario. The overall objective of SDG 7 is *universal access to affordable, reliable, sustainable and modern energy services* by 2030, which is a key prerequisite to putting an end to global poverty worldwide and makes its achievement an overarching policy goal for those countries directly concerned. Realisation of this target primarily relies on strong policy commitment to create the frameworks to attract investment, including for the last 10-15% of the un-electrified population that typically is the slowest and most costly to connect. To achieve clean cooking for all, awareness through education is a vital success factor, along with new programmes and policies to empower women, who are central decision-makers in household cooking matters and can help deliver appropriate solutions tailored to local conditions and needs.

In a first step, we use the IEA's World Energy Model (WEM)[11] to assess the energy sector implications and requirements to reach universal access to modern energy by 2030. For the analysis of electricity access, we combine cost-optimisation with new geospatial analysis that takes into account current and planned transmission lines, population density, resource availability and fuel costs.[12] We consider all technologies and fuels in the analysis, including fossil fuels, as achieving universal access to modern energy by 2030 will not cause a net increase in global GHG emissions: a small CO_2 increase is more than offset by declines in other GHG emissions, notably methane from reduced biomass combustion (IEA, 2017a).

In a second step, we consider goals related both to addressing climate change and outdoor air pollution. Our analysis takes these environmental goals as equally important and does not weigh short-term benefits against longer term gains. In terms of climate change, the point of departure is *WEO*'s established 450 Scenario (IEA, 2016b). The analytical time horizon of *WEO* is 2040, so the scenario is designed to take ambitious action, using all available technologies (even if not commercially available today at significant scale), to keep the world on track through the projection period towards the long-term objectives of the Paris

11. For details, see: *www.iea.org/weo/weomodel/.*

12. The analysis is undertaken in collaboration with the Swedish Royal Institute of Technology (KtH) Stockholm. For details, see (IEA, 2017a).

Agreement (see Box 3.4). The resulting energy sector pathway to 2040, although comparable, is not identical with the 450 Scenario, as the required additional achievements of universal access and reduced air pollution lead to different outcomes, for example, higher demand for energy services (from universal access), higher fuel input in thermal combustion processes resulting from the use of air pollution control devices, and differences in technology choices to encompass the different policy goals in an optimal fashion (Box 3.3).

Box 3.3 ▷ What's different in a Sustainable Development Scenario?

There are many conceptual similarities between climate scenarios, such as the 450 Scenario, and the Sustainable Development Scenario. This is because they both aim at mitigating climate change, and because many of the available technology solutions for the multiple goals are similar. For example, technologies that do not rely on combustion processes can avoid air pollution and mitigate climate change at the same time. Yet, there are also important differences. These differences are partly related to the time scales involved. The target to achieve universal energy access by 2030 and the significance of the impact of air pollution on human health already today mean that technology choices in the Sustainable Development Scenario can differ from a scenario that is solely driven by climate considerations, whose time scale is longer. For example, in the power sector, decentralised modular technology solutions with short lead times (such as solar PV or wind power) will be able to respond more easily to the simultaneous challenges of the Sustainable Development Scenario than centralised power generation facilities can. Among renewables, biomass is the counter example, not only because a diminished role for traditional biomass in cooking is an explicit target of the Sustainable Development Scenario. Modern uses of biomass as a decarbonisation option is also somewhat less relevant in a Sustainable Development Scenario than in a dedicated climate scenario. The reason is that biomass is a combustible fuel, which means that its use as a decarbonisation option requires post-combustion control to limit air pollutant emissions in the Sustainable Development Scenario, which may, in some instances, render its use more costly than that of available alternatives.

In terms of air pollution, the Sustainable Development Scenario neither delivers a pollution-free atmosphere, nor aims for the achievement of a specific universal air quality goal within the projection period (as circumstances vary widely even within individual countries). But the scenario does offer a pragmatic agenda for a drastic reduction of air pollutants. For this purpose, the scenario assumes widespread use of existing technologies and policy practices to reduce air pollutant emissions through the use of post-combustion treatment technologies. It also assumes that policy signals are sufficiently strong and aligned to ensure that energy investment decisions take into account air pollution and climate goals at the same time, in order to avoid undesired lock-in effects and reduce the overall costs of compliance. For example, retrofitting existing inefficient coal-fired power plants with scrubbers or filters to reduce air pollution today is not economic if the plants are to be retired tomorrow to meet the shared climate goal.

Table 3.3 ▷ Selected policy priorities to address climate change and reduce air pollutant emissions in the Sustainable Development Scenario*

Address climate change	Reduce air pollution
Introduction of CO_2 prices by sector and region: • In selected regions, staggered introduction of CO_2 prices for the industry and power sectors and, where appropriate, in aviation; the level and pace of introduction depends on country circumstances (see Chapter 1).	**Stringent emissions limits for new and existing combustion plants:** • For plants above 50 MW_{th} using solid fuels, emissions limits are set at 30 mg/m^3 for PM and 200 mg/m^3 for NO_X and SO_2. Existing plants need to be retrofitted within ten years. • Emission limits for plants below 50 MW_{th} depending on size, fuel and combustion process.[13] • Industrial processes required to be fitted with the best available techniques in order to obtain operating permits.[14]
Phase out fossil-fuel consumption subsidies: • Pricing reforms to fully remove the incentives for wasteful consumption of fossil fuels.	**Improved fuel quality:** • Phase-out of fuel with sulfur content higher than 0.5% for heavy fuel oil, 0.1% for gasoil and 50 ppm for road gasoline and diesel.
Increased support to low-carbon technologies: • Increased support to the use of renewables, nuclear and CCS. • RD&D on innovative technologies and support to innovative market designs.	**Fuel switching to lower emissions fuels:** • Increased coal-to-gas switching and use of low-sulfur fuels in national and international maritime transport.
Strong push for efficiency in the industry and transport sectors: • For industry, the introduction or strengthening of existing minimum energy performance standards (MEPs) for electric motor-driven systems. • For transport, stringent fuel-economy standards for light-duty vehicles (passenger and commercial) as well as road freight trucks.	**Higher road vehicle emissions standards:** • For light-duty diesel vehicles: limits as low as 0.1 grammes per kilometre (g/km) for NO_X and 0.01 g/km for PM. For heavy-duty diesel vehicles and machinery: limits of 3.5 g/km for NO_X and 0.03 g/km for PM. • For all vehicles, full on-road compliance by 2025. • A ban on light-duty gasoline vehicles without three-way catalysts and tight evaporative controls, and a phase-out of two-stroke engines for two/three-wheelers.
Strong efficiency policies for appliances and buildings: • Introduction or strengthening of existing MEPs for appliances, lighting, heating and cooling. • Introduction of mandatory energy conservation building codes.	**Stringent controls for biomass boilers in residential buildings:** • Emissions limits for biomass boilers set at 40-60 mg/m^3 for PM and 200 mg/m^3 for NO_X.[15]

* See Annex B for a comprehensive list of policies assumed in the Sustainable Development Scenario.

Note: RD&D = research development and demonstration; CCS = carbon capture and storage; MW_{th} =megawatts thermal; mg/m^3 = milligrammes per cubic metre; g/km = grammes per kilometre; ppm = parts per million.

13. The Medium Combustion Plants Directive of the European Union and the revised US Clean Air Standards from 2015 provided the guidelines for achievable emission limit values in these cases.

14. The BAT Reference Documents of the Industrial Emissions Directive of the European Union and the New Source Performance Standards in the United States are important sources for best available techniques.

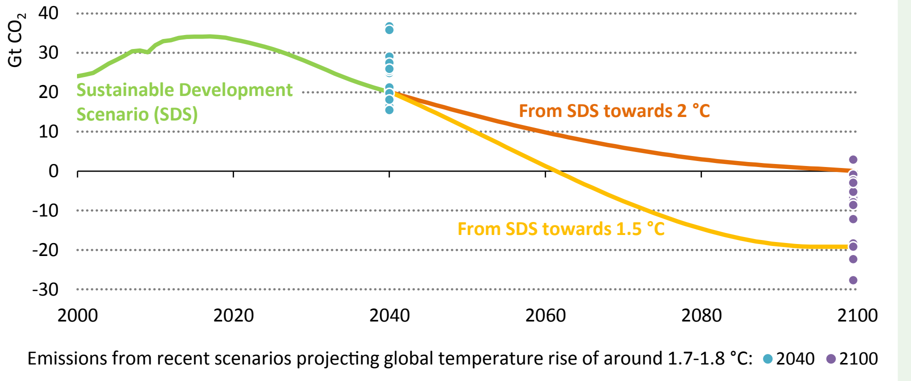
15. The European Union's EcoDesign Directive provides a guide for implementation.

Box 3.4 ▷ The Sustainable Development Scenario and the Paris Agreement

The Paris Agreement sets a collective goal of "holding the increase in the global average temperature to well below 2 °C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 °C". While no definition of "well below 2 °C" is provided, the Agreement is nonetheless clear that achievement of the goal should rest on three pillars: (i) global GHG emissions peaking as soon as possible, (ii) rapid emissions reductions thereafter, and (iii) achievement of a balance between anthropogenic emissions by sources and removals by sinks (i.e. net-zero emissions) in the second-half of this century.

In the Sustainable Development Scenario, CO_2 emissions from energy and industrial processes peak before 2020 and show a steep decline through the *Outlook* period, so for these emissions the scenario is clearly consistent with the first two of the Paris Agreement pillars (Figure 3.12). This is achieved while simultaneously making marked progress on energy access and air quality, thereby also fulfilling those aspects of the SDG agenda and respecting the Paris Agreement's additional aims to ensure sustainable development and eradicate poverty. By 2040, CO_2 emissions in the Sustainable Development Scenario are at the lower end of a range of estimates drawn from the most recent publicly available emissions scenarios, all of which project a mean global temperature rise in 2100 of between 1.7 °C and about 1.8 °C. The wide range of 2040 emissions levels is due to differing assumptions affecting not only the peak and decline of energy-related CO_2, but also emissions of other GHGs and CO_2 from land-use.

Figure 3.12 ▷ The Sustainable Development Scenario relative to other recent decarbonisation scenarios



Emissions in the Sustainable Development Scenario in 2040 are at the lower end of a range of recent decarbonisation scenarios, though the long-term trajectory is crucial to determining the final temperature outcome

Note: Chart shows energy and process-related CO_2 emissions. Dots represent emissions in 2040 and 2100 from all Representative Concentration Pathway (RCP) 2.6 scenarios in the most recent Shared Socioeconomic Pathways (SSP) database (IIASA, 2017).

The long-term temperature outcome beyond the Sustainable Development Scenario in 2040 is dependent on how quickly the third Paris Agreement pillar of net-zero global emissions in the second-half of the century is achieved, and whether global emissions will subsequently become negative. If CO_2 emissions decline steadily to net-zero by 2100, this would be in line with holding global warming to 2 °C. To increase the likelihood of a lower ultimate temperature rise, emissions will need to decline more quickly to zero and, potentially, turn negative. A future period of net-negative emissions would allow for a slower emissions reduction path for the same temperature outcome (although the temperature rise would likely overshoot before falling back), or a lower temperature rise for the same path to zero emissions. To be in line with staying below 1.5 °C, emissions could fall to zero by 2060 and then become very significantly net-negative, reaching about -19 Gt by 2100. Although this level of negative emissions falls within the range projected by other scenarios, the challenge of achieving it should not be underestimated. Global negative emissions would require large-scale deployment of technologies which achieve net removal of CO_2 from the atmosphere, and all such technologies face severe technical, economic and resource constraints.[16]

The complexity of the climate system means that the ultimate temperature outcome of any emissions trajectory cannot be known precisely. Despite this uncertainty, increasing the chances of a lower temperature rise while limiting reliance on future negative emissions means accelerating the point of zero emissions. The likelihood of a faster reduction to zero will be increased by more ambitious early action, such as additional investment to avoid locking in high-carbon infrastructure and to create conditions for increased innovation. The Faster Transition Scenario (section 3.5) describes one such accelerated climate-focused pathway.

Analytically, we approach the second step of the analysis by running the WEM so as to achieve climate goals, and iterating with IIASA's GAINS model over the implications for air pollutant emissions that arise from the achievement of climate goals and universal energy access. The objective is to identify a portfolio of least-cost technology options that achieve climate goals and air pollution objectives, while also delivering universal energy access to modern energy. A host of policy measures is available to support the achievement of climate change and air pollution objectives (Table 3.3). In the Sustainable Development Scenario, they are selected for each country individually, according to specific national circumstances, with two intentions: first, to increase the pace of the energy transition towards the use of low-carbon technologies, essential to meet climate as well as air

16. For example, the global maximum potential of one such technology, combining biomass energy with carbon capture and storage (BECCS), is estimated at only around 10-12 Gt CO_2 per year, and this would require enormous land area for cultivation (Smith et al., 2016). Moreover, for the emissions to be truly negative all the biomass would need to be fully sustainable and not lead to additional emissions due to land-use change. Other technologies could include capturing and storing CO_2 directly from the air; capturing CO_2 from biomass combustion and using it as a feedstock (such as to grow useful algae); or accelerating the natural mineralisation of CO_2 through techniques known as enhanced weathering.

pollution goals, and, second, to ensure that existing policy and technology best-practices for reducing air pollution accompany the low-carbon carbon transition so as to significantly improve air quality.

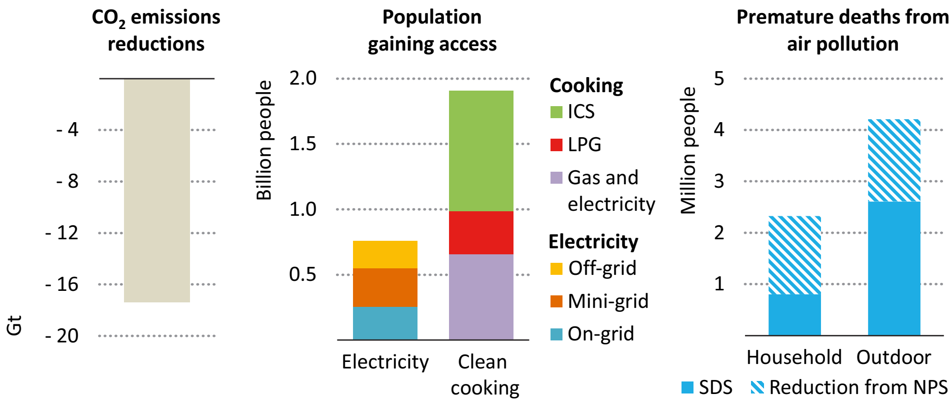
3.4.3 Trends in the Sustainable Development Scenario

Benefits of the Sustainable Development Scenario

Efforts to achieve energy-related SDGs in the Sustainable Development Scenario deliver three central benefits. First, achievement of universal access to modern energy by 2030 (SDG 7.1) in the Sustainable Development Scenario means that 1.3 billion people gain access to electricity by 2030 (around twice as many as in the New Policies Scenario) and 2.9 billion people get access to clean cooking by 2030 (2 billion more than in the New Policies Scenario). Achievement of SDG 7.1 supports the pursuit of many other non-energy-related SDGs, such as eliminating poverty (SDG 1), raising living standards through the provision of basic services, including healthcare, education, water and sanitation (SDGs 3,4,6); improving household incomes (SDG 8); and making settlements and infrastructure more resilient (SDG 11). It also helps to minimise household air pollution in developing countries with important benefits for human health, reducing the related premature deaths by 1.8 million in 2030 (1.5 million in 2040), relative to the New Policies Scenario (Figure 3.13). Second, efforts to accelerate the low-carbon energy transition to address climate change in the Sustainable Development Scenario bring down cumulative CO_2 emissions by 195 Gt over the period to 2040 (SDG 13), relative to the New Policies Scenario, putting the world on track to address climate change and helping to reduce outdoor air pollution. These efforts also help to achieve SDG 7.2 (substantially increase the share of renewable energy in the global energy mix by 2030) and SDG 7.3 (double the global rate of improvement in energy efficiency by 2030). The share of renewables in final energy consumption more than doubles in 2030 relative to the 2016 level,[17] and the annual rate of improvement in global energy intensity exceeds the level achieved between 1990 and 2010 by a factor of 2.5, overshooting the target. Third, the pursuit of policies directly to reduce outdoor air pollution also bring about significant improvements in human health, reducing the number of people dying prematurely from the impacts of outdoor air pollution by 1.6 million in 2040, relative to the New Policies Scenario (SDG 3.9).

17. Traditional use of biomass for cooking is not counted as renewable energy in this quantification. If the traditional use of biomass is included (according to the tracking methodology for SDG 7.2), the renewable energy share increases more modestly, as the reduction in the traditional use of biomass offsets the increase of modern renewables in the energy mix.

Figure 3.13 ▷ **Impacts of the Sustainable Development Scenario relative to the New Policies Scenario, 2040**



Policies of the Sustainable Development Scenario contribute to increasing energy access, improving human health and addressing climate change

Note: NPS = New Policies Scenario; SDS = Sustainable Development Scenario; ICS = improved cookstoves.

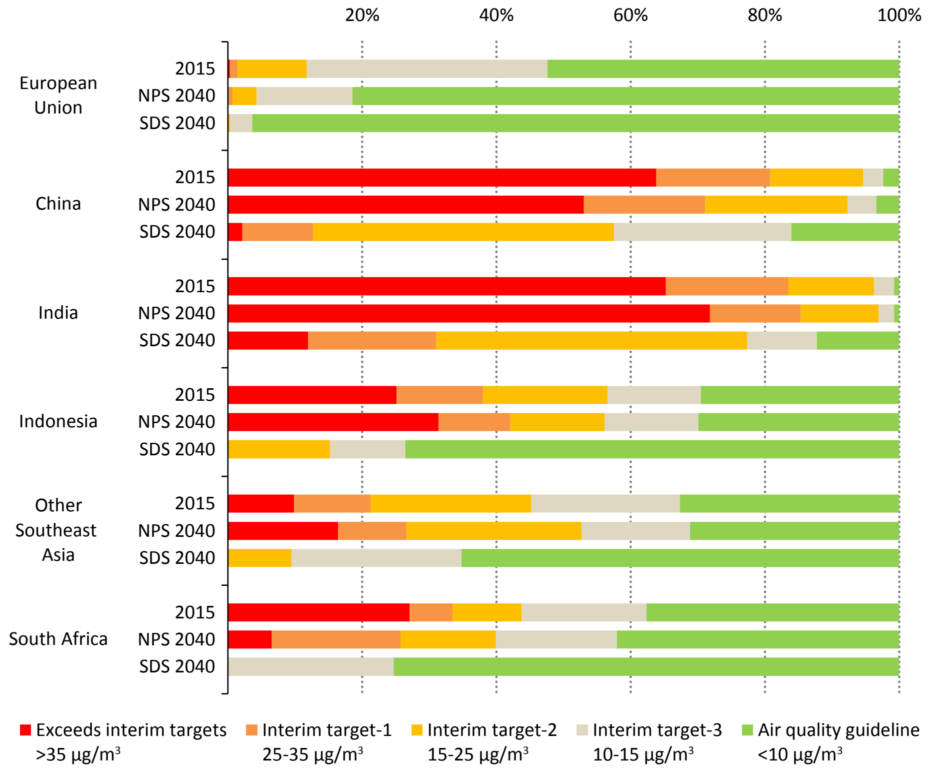
Sources: IEA analysis; IIASA.

The reduction of premature deaths from outdoor air pollution is directly linked to the improvements in ambient air quality. In the New Policies Scenario, large parts of the population in many countries continue to live in 2040 with a level of air quality that does not comply with the WHO guideline for average annual $PM_{2.5}$ concentrations.[18] Worse, in many countries, large parts of the population will be living with air quality that does not meet even the WHO interim target-1 (Figure 3.14). For example in India, in the New Policies Scenario, despite the current policy attention to the issue, 72% of the population in 2040 are projected to live at a concentration level above the WHO target-1 (seven percentage points above today's level), and only 1% at a level that is compatible with the ultimate WHO guideline. The Sustainable Development Scenario brings about significant improvements in air quality, even though a pollution-free environment is not fully achieved. India sees the share of the population exposed to average annual concentrations of $PM_{2.5}$ above the WHO interim target-1 fall to 12% in 2040. In China, the share of the population living above WHO interim target-1 shrinks to 2% in 2040. In Indonesia, the Sustainable Development Scenario implies that the entire population could be subject to concentrations of $PM_{2.5}$ that are compatible at least with the WHO target-2 by 2040 (25 μg/m^3); three-quarters would have a level compatible with

18. The WHO air quality guideline defines a maximum concentration of $PM_{2.5}$ at 10 μg/m^3. Below this level, there is no evidence (95% probability) of increased cardiopulmonary and lung cancer mortality in response to long-term exposure to $PM_{2.5}$. The WHO has introduced a series of interim targets that are less stringent, but represent an attainable set of milestones on the path to better air quality.

the air quality guideline. Similarly, in South Africa, no part of the population is exposed to $PM_{2.5}$ concentration levels worse than WHO target-3 and the majority lives in areas compatible with the air quality guideline.

Figure 3.14 ▷ Shares of population exposed to various $PM_{2.5}$ concentrations by WHO interim targets/guidelines in selected regions by scenario



The Sustainable Development Scenario is a major leap forward towards cleaner air, relative to the level of the New Policies Scenario

Note: NPS = New Policies Scenario; SDS = Sustainable Development Scenario; µg/m³ = microgrammes per cubic metre.

Source: IIASA.

Emissions trends

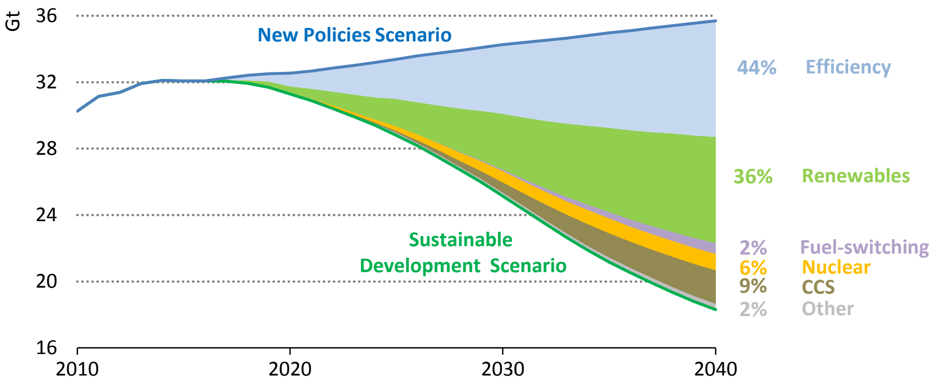
All emissions fall in the Sustainable Development Scenario, including energy-related CO_2 emissions as well as air pollutants. Cumulative CO_2 emissions to 2040 in the Sustainable Development Scenario are 195 Gt lower than in the New Policies Scenario, falling to 18.3 Gt in the year 2040. $PM_{2.5}$ emissions drop by about 80% in 2040, relative to the New Policies Scenario, while SO_2 emissions fall by 70% and NO_X emissions by 50%. The emissions declines are facilitated by the package of policies that is adopted in the Sustainable Development

Scenario, although the degree to which each individual policy contributes to the decline in CO_2 and air pollutant emissions varies.

Additional policies to promote a low-carbon transition in the energy sector are the reason for the drop in CO_2 emissions in the Sustainable Development Scenario, relative to the New Policies Scenario (Figure 3.15). Measures to increase energy efficiency and scale up the use of renewables in power generation and beyond are responsible for most of the savings, although carbon capture and storage is another important element, in particular in the industry sector. The contribution of each sector to emissions savings reflects both their current level of emissions and the degree to which decarbonisation efforts already make progress in the New Policies Scenario, on the back of existing and planned policies.

3

Figure 3.15 ▷ Global CO_2 emissions reductions in the New Policies and Sustainable Development Scenarios



Energy efficiency and renewables account for 80% of the cumulative CO_2 emissions savings in the Sustainable Development Scenario

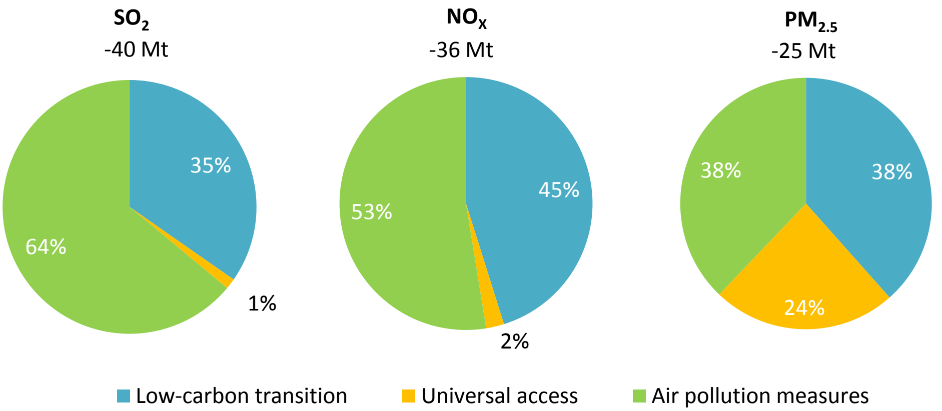
The power sector is the largest contributor to overall savings in CO_2 emissions due to the falling costs of renewables and lower electricity demand from increased energy efficiency in end-uses. In the Sustainable Development Scenario, more than 60% of cumulative CO_2 emissions savings occur in the power sector, relative to the New Policies Scenario. The industry and buildings sectors, the two largest sources of electricity demand, are, indirectly, key contributors to power sector emissions savings; around 15% of the total projected emissions decline is attributable to the increasingly efficient use of electricity.

The transport sector is the second-largest contributor to cumulative CO_2 emissions savings, at around 20% of total savings relative to the New Policies Scenario. The pace of decline of transport emissions, however, does not nearly reflect its weight in emissions; by 2040, transport becomes the largest source of global CO_2 emissions in the Sustainable Development Scenario, overtaking power generation. The reason is that combined emissions from road freight transport, shipping and aviation fall much more slowly than those of other sectors.

Direct emissions from the industry sector are the third-largest contributor to overall CO_2 emissions savings in the Sustainable Development Scenario, relative to the New Policies Scenario, at just above 10% of the cumulative total. The majority of the savings comes from the energy-intensive iron and steel and cement sectors.

The buildings sector makes only a small contribution to direct overall emissions savings in the Sustainable Development Scenario, relative to the New Policies Scenario, at around 3% of the cumulative total. The generally small amount of direct CO_2 emissions from the buildings sector is the main reason for its relatively modest contribution to overall savings (36% of building energy demand today is satisfied by electricity and heat).

Figure 3.16 ▷ Air pollutant emissions savings by policy area in the Sustainable Development Scenario relative to the New Policies Scenario, 2040



Air pollution control is the main contributor to reducing outdoor air pollution; achieving universal access to modern energy is particularly important for reducing $PM_{2.5}$ emissions

Sources: IEA analysis; IIASA.

In contrast to CO_2, the global decline in air pollutant emissions is attributable to all three pillars of the Sustainable Development Scenario (Figure 3.16). The long-term transition to a low-carbon energy sector is an important contributor; ultimately, the most effective way to minimise the impact of energy sector activity on human health is to avoid related air pollutant emissions altogether. But the rates of turnover in the energy sector, even in the Sustainable Development Scenario, are slow. This makes the use of technology and policy best practice to reduce air pollution important to achieve a meaningful decline in air pollutant emissions through 2040. Post-combustion control technologies are readily available and cost-effective; their use typically hinges on the existence of appropriate and stringent regulatory frameworks, including not only setting emissions limits, but also monitoring and enforcement (IEA, 2016a). The use of these measures is effective both to cut air pollutant emissions in the near-term and to facilitate their longer term decline, as many of the installations subjected to controls are still in operation by 2040 in the Sustainable Development Scenario.

Achieving universal access to modern energy by 2030 accounts for about a quarter of the reduced $PM_{2.5}$ emissions in the Sustainable Development Scenario. However, its relevance for human health is even greater than this. Achieving universal energy access alone all but eliminates household air pollution by 2030 and is the main reason why related premature deaths fall.

SPOTLIGHT

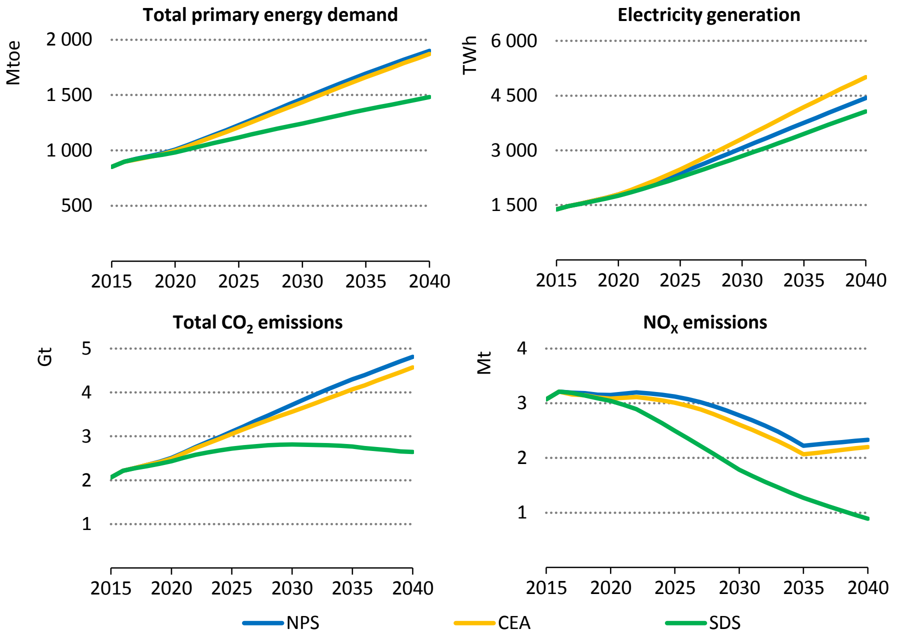
India's Clean Energy Ambitions – How far from the Sustainable Development Scenario?

India has announced ambitious clean energy plans, including for renewables and nuclear in power generation and electric cars in transport, as well as an ambitious electrification programme that aims to provide access to all by the early 2020s. Achievement of the latter target is making significant progress and, thanks to a big push for rural electrification in recent years, the "access to all" target is already fully incorporated in the New Policies Scenario (IEA, 2017a). However, the targets for road transport and power generation are not assumed to be fully reached in the New Policies Scenario, as our analysis shows that further measures will be needed to overcome some of the barriers to their implementation. Nonetheless, in this Spotlight, we explore how India's energy future could unfold if those targets were fully met in a Clean Energy Ambition (CEA) case, benchmarking against the New Policies and Sustainable Development Scenarios to derive policy insights (Figure 3.17).

In the transport sector, India's Minister for Power, Coal and New & Renewable Energy in 2017 announced that the government is looking for "India [to] be 100% on electric vehicles by 2030". This target could be more ambitious than that of any country in the world in terms of timing and scale, depending how it plays out. For example, if the target was interpreted as all car sales to be electric by 2030, then this would correspond to annual sales of electric cars of roughly 13 million by then. Today, only 760 thousand electric cars are sold worldwide annually. The Minister cited the example of light-emitting diode (LED) bulbs, where bulk tendering enabled the government to reduce the procurement price of these light bulbs by 80% within just two years, supported by global cost reductions.

Recognising the call on the power sector to meet growing demand, the Ministry of Power has set ambitious targets for the deployment and integration of 175 GW of renewables by 2022. This includes 60 GW of utility-scale solar, 40 GW of rooftop solar, 60 GW of wind, 10 GW of bioenergy and 5 GW of small hydro. These targets are the first step towards realising the target of meeting 40% of electricity from non fossil-fuel sources (renewables and nuclear) by 2030, announced by the Prime Minister.

Figure 3.17 ▷ Key indicators for India in the Clean Energy Ambition Case and the New Policies and Sustainable Development Scenarios



An integrated energy policy approach leads to lower emissions for similar costs

Note: NPS = New Policies Scenario; CEA = Clean Energy Ambition Case; SDS = Sustainable Development Scenario; Mtoe = million tonnes of oil equivalent; Gt = gigatonnes; Mt = million tonnes; TWh = terawatt-hour.

In the Clean Energy Ambition Case, we assume the same level of energy service demand as in the New Policies Scenario through 2040. Electricity demand rises above the level of the New Policies Scenario, driven by higher transport demand, increasing the share of electricity in final energy consumption to 27% in 2040, compared to 23% in the New Policies Scenario. Oil demand falls to compensate, but overall primary energy demand is only slightly lower, as the fuel input to power the additional electricity demand increases. The result is that, despite a decrease in transport-related emissions and the increased share of clean electricity in the power mix, overall emissions of local pollutants and CO_2 emissions remain very close to the levels in the New Policies Scenario: the savings in transport are virtually offset by the increased fuel use in power generation.

In the Sustainable Development Scenario, a broader, integrated set of policies is applied, involving improved energy efficiency and the deployment of renewable energy sources across all sectors. This leads to much lower energy demand growth, albeit satisfying a level of energy service comparable to the New Policies Scenario. In the Sustainable Development Scenario, the electrification of transport continues, but efficiency measures in cooling, appliances and motors moderate electricity demand growth. The power sector moves towards even higher reliance on renewables (45% in 2030, 60% in 2040) than in the Clean Energy Ambition Case, in combination with higher use of natural gas, while applying power plant emissions control technologies. This integrated approach delivers lower emissions levels in cities and from India's energy sector overall, and yields lower consumer expenditures at only slightly higher overall investment needs.

In conclusion, the ambitions expressed by India's government are a noteworthy and laudable step to put India on a path that reconciles economic growth with secure provision of energy and environmental and social needs. Further policy efforts will be required, especially in terms of energy efficiency improvements, to ensure even greater benefits for consumers in terms of reduced energy and environmental costs.

Energy trends

The policies adopted to support the objectives of the Sustainable Development Scenario deliver a significantly different outlook for the energy sector than that in the New Policies Scenario (Table 3.4). Total primary energy demand barely grows over today's level, as increasing energy efficiency supports a much steeper decline in energy intensity per unit of economic output of 3.2% per year on average (compared with 2.3% in the New Policies Scenario). The fuel mix also changes: as efforts intensify to make a low-carbon transition, the CO_2 intensity per unit of economic output falls by 5.5% per year on average, nearly twice the rate of the New Policies Scenario.

Coal demand peaks before 2020 in the Sustainable Development Scenario and is cut by half, to just above 2 500 million tonnes of coal equivalent (Mtce) in 2040, relative to the New Policies Scenario, equivalent to an average annual decline of 3% over the projection period. About 90% of the decline in coal use in 2040 occurs in the power sector alone, where the share of coal in electricity generation falls to 6% in 2040 (from 37% today). Phasing out the use of unabated coal-fired power generation (i.e. without CCS) is a key feature of the power sector transition in the Sustainable Development Scenario; such generation is cut by more than half by 2030 and by 90% by 2040, meaning that less than half of remaining coal-fired power generation is unabated by the end of the projection period. The majority of CCS deployment is confined to a small number of countries, in particular China and the United States, which hold more than 80% of global CCS capacity in the Sustainable Development Scenario.

Oil demand peaks soon after coal in the Sustainable Development Scenario and declines to 73 million barrels per day (mb/d) in 2040, nearly 32 mb/d below the level of the New Policies Scenario. The majority of the decline in oil demand comes from transport, the largest oil consumer today, as electric cars make significant inroads and, at around 875 million vehicles, constitute more than 40% of the global car stock in 2040, addressing climate change as well as local air pollution. Cars and trucks become much more fuel efficient in the Sustainable Development Scenario; by 2040, an average truck, for example, uses about 40% less fuel than today. Petrochemical feedstock is the only area in which continued growth in oil demand occurs, at nearly the same level as in the New Policies Scenario. Use of oil as feedstock is connected to the continued growth in demand for chemical-based products, such as plastics.[19]

Table 3.4 ▷ World primary energy demand in the Sustainable Development Scenario (Mtoe)

	2016	2025	2030	2035	2040	Change relative to NPS* 2025	Change relative to NPS* 2040
Coal	3 755	3 023	2 457	2 047	1 777	-21.3%	-54.8%
Oil	4 388	4 247	3 966	3 604	3 306	-8.3%	-31.6%
Gas	3 007	3 397	3 510	3 492	3 458	-1.1%	-20.6%
Nuclear	681	920	1 120	1 278	1 393	9.7%	39.0%
Renewables**	1 251	1 994	2 636	3 350	4 049	11.3%	39.1%
Hydro	350	429	489	543	596	3.8%	11.9%
Modern biomass	676	932	1 110	1 290	1 457	5.0%	17.1%
Other renewables	225	633	1 037	1 517	1 996	29.2%	76.2%
Traditional use of biomass***	678	340	148	126	102	-47.2%	-81.7%
Fossil fuel share	81%	77%	72%	66%	61%		
of which: equipped with CCS	0%	1%	3%	7%	10%		
Renewables share	9%	14%	19%	24%	29%		
Energy intensity (toe/$1000 GDP-PPP)	0.11	0.08	0.07	0.06	0.05	-8%	-20%
Total	**13 760**	**13 921**	**13 836**	**13 897**	**14 084**	**-8.3%**	**-19.9%**

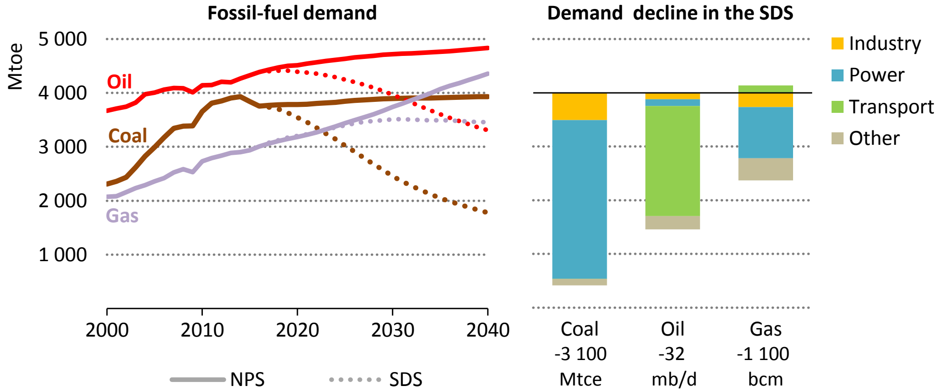
* NPS = New Policies Scenario. ** Excludes traditional use of biomass. *** Includes both traditional and improved biomass cookstoves. Note: toe = tonne of oil equivalent; PPP = purchasing power parity.

Natural gas is the only fossil fuel that does not experience a pronounced peak and decline in the Sustainable Development Scenario; its use grows by around 580 billion cubic metres (bcm) and stabilises at just below 4 300 bcm from around 2030 (Figure 3.18). Natural gas emits much lower levels of CO_2 than coal and oil. Its combustion is low in emissions of $PM_{2.5}$ and SO_2 (unlike coal and oil), and, at a current global average, involves NO_X emissions per unit of energy roughly 40% that of oil and 60% that of coal. The market for natural gas, however, is different from that in the New Policies Scenario (see Chapter 11). While industry is the main source of natural gas demand growth in both scenarios, this is followed in the

19. See Chapter 4 for a discussion of the petrochemicals sector.

Sustainable Development Scenario by transport (in particular road freight and shipping) and residential buildings (particularly for cooking). In the power sector, the use of natural gas peaks around 2030 and then declines by 2040 to a level that is 180 bcm below that of today.

Figure 3.18 ▷ Fossil-fuel demand by scenario and decline by sector in the Sustainable Development Scenario relative to the New Policies Scenario, 2040



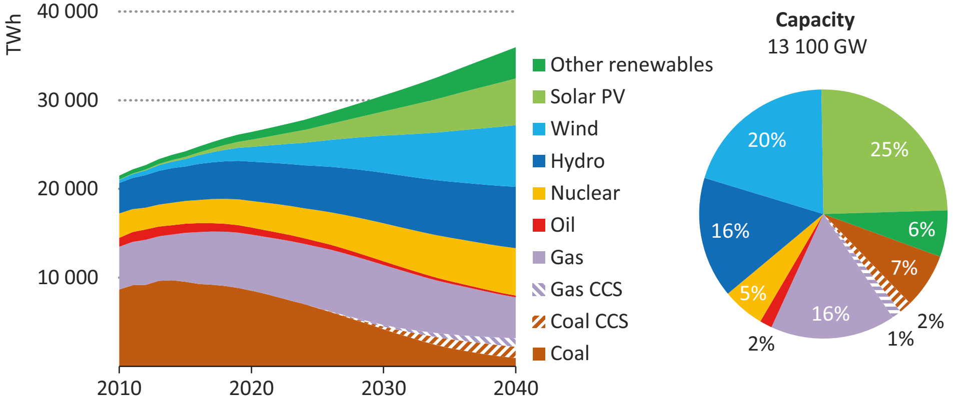
In the Sustainable Development Scenario, natural gas overtakes first coal and then oil to become the first among fossil fuels by the late 2030s

Note: NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

The traditional use of biomass for cooking in developing countries diminishes in the Sustainable Development Scenario, as a result of policies that promote alternative fuels for cooking and the use of advanced cookstoves. By 2040, traditional use of biomass is around 85% lower than today (compared to a decline of less than 20% in the New Policies Scenario), with the remainder used in improved cookstoves. In contrast, in the Sustainable Development Scenario, the modern use of bioenergy in the power, industry and transport sectors almost triples over today's global level, representing an increase of 30% over the level of the New Policies Scenario. Modern use of bioenergy is a promising and readily available option to reduce CO_2 emissions across various sectors, ranging from residential heating, to biomass boilers for low- to medium-heat supply in industrial applications, to the use of biofuels in transport and their use for power generation. But biomass combustion gives rise to emissions of $PM_{2.5}$, which need to be removed to minimise health impacts. This requires using post-combustion filters (where applicable and cost-effective against other options), which holds back further deployment in the Sustainable Development Scenario. Further, for biomass to fully contribute to GHG emission reductions, it must be cultivated and harvested in a way that does lead to additional emissions from direct or indirect land-use change.

The use of other low-carbon fuels, including renewables and nuclear, increases significantly in the Sustainable Development Scenario; by 2040, their use is around 40% higher than in the New Policies Scenario. The main contribution comes from renewables and extends across all sectors. In the power sector, renewables expand to provide over 60% of global electricity generation by 2040 (Figure 3.19). An additional 15% comes from nuclear power, but nuclear development in the Sustainable Development Scenario is limited to those regions with existing or planned nuclear power plants and their supporting regulatory structures. Renewables become the dominant option for meeting new electricity demand and displacing existing fossil-fuelled generation. Wind and solar PV, in particular, become the two largest technologies in terms of installed capacity, providing one-third of all electricity in 2040. The use of renewables also expands in end-use sectors: biofuels become an important low-carbon fuel in transport, in particular for trucks, planes and ships where other alternatives are limited. Their use displaces 7.4 million barrels of oil equivalent per day (mboe/d) by 2040, up from 4.1 mboe/d in the New Policies Scenario. In the industry and buildings sectors, the direct use of renewables also rises, in particular to satisfy heat demand. By 2040, 15% of heat demand from the two sectors is directly supplied from renewable sources, more than twice today's level.

Figure 3.19 ▷ Power generation by source (left) **and installed capacity** (right) **in the Sustainable Development Scenario, 2040**



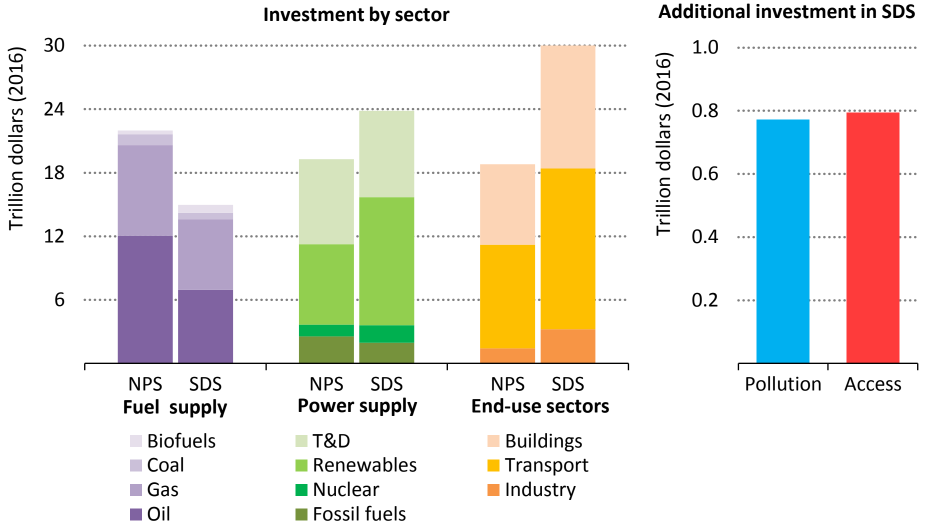
Power generation all but decarbonises in the Sustainable Development Scenario

Implications for energy investments and energy expenditures

Pursuit of the policy goals of the Sustainable Development Scenario comes with important benefits (the impacts on human health and climate change are described above). But its achievement requires significant additional investment in the energy sector itself, an additional $9 trillion net through 2040, relative to the investment needs in the New Policies Scenario (Figure 3.20). An additional $7 trillion is used to improve the energy efficiency of end-use sectors, along with further investment for the scale up of key technologies, such as electric cars, and the direct use of renewables for heat supply in the industry and buildings sectors.

This investment is partially offset by the resulting lower need for investment in fossil-fuel supply and fossil-fuel power generation, which reduces the overall investment requirements by $8 trillion through 2040, and by lower operational and fuel costs. Investment in low-carbon technologies in the power sector also rises; additional investment requirements in renewables and nuclear drive up total power generation investment needs by $5.7 trillion through 2040, despite the falling costs of renewables technologies and lower investment needs in fossil-fuel based power generation capacity.

Figure 3.20 ▷ Cumulative investment needs by sector in the New Policies and Sustainable Development Scenarios, 2017-2040



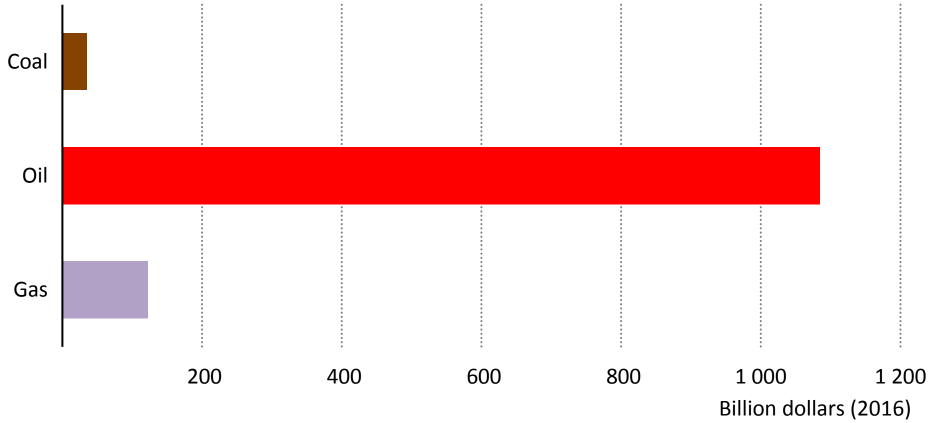
The energy transition is driven by higher investment in energy efficiency and low-carbon technologies in end-use sectors and power generation; fossil-fuel investment declines

Note: NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

Compared to the global energy sector investment for achieving the energy transition in the Sustainable Development Scenario, the level of incremental investment needed in developing countries to achieve universal access to modern energy by 2030 is minor, at $433 billion cumulatively to 2030 ($793 billion to 2040). About 90% of the additional access-related investment to 2030 is to achieve full access to electricity, and much of this is for decentralised connections: $187 billion and $89 billion for mini-grids and off-grid installations respectively, versus $114 billion for grid-based access. The additional investment needed for pollution control in the Sustainable Development Scenario is of a similar magnitude to that for access, at $772 billion to 2040.

The significant investment needs of the Sustainable Development Scenario should be viewed against the background of changes in expenditure on energy. Oil expenditure, historically the predominant part of consumer spending, falls as of the mid-2020s as demand (and prices) fall. End-user spending on electricity rises in turn, driven by expanding electricity demand (such as for road vehicles), and despite the increasing efficiency of electricity use. For fossil-fuel importing countries, the energy transition of the Sustainable Development Scenario entails significant savings in fossil-fuel import bills, both an economic and energy security consideration (Figure 3.21).

Figure 3.21 ▷ Fossil-fuel import bill savings in importing regions in the Sustainable Development Scenario relative to the New Policies Scenario, 2040



The Sustainable Development Scenario brings about significant fossil-fuel import bills savings in all importing regions

3.5 What does it take to achieve a faster low-carbon energy transition?

The Sustainable Development Scenario takes ambitious steps towards the transition of the energy sector based on low-carbon technologies, as a means of addressing climate change and reducing air pollution. The scenario is designed to support the achievement of climate change commitments, the full realisation of which is contingent both on commensurate efforts outside the energy sector and the pace of energy sector decarbonisation after 2040. It reduces energy-related CO_2 emissions to 18.3 Gt in 2040, more than 17 Gt below the level of the New Policies Scenario.

Stronger policy intervention than that already assumed in the Sustainable Development Scenario could facilitate an even faster transition, essentially further frontloading the low-carbon energy transition into the first-half of the century. The IEA has developed such a scenario, using the WEM and the Energy Technology Perspectives models, which was presented as an input to the German 2017 G-20 Presidency (IEA, 2017c).[20] The scenario,

20. The "Beyond 2 °C Scenario" of Energy Technology Perspectives 2017 is another recent IEA scenario (IEA, 2017d).

referred to in what follows as the "Faster Transition Scenario",[21] is a climate-dominant scenario in that it is not conceived to reach multiple policy goals in the way that the Sustainable Development Scenario has been developed. As a result, the Faster Transition Scenario achieves lower reductions in air pollutant emissions (which stem from the use of zero-emission technologies) and lower levels of energy access (from reductions in low-carbon technology costs due to faster deployment) than the Sustainable Development Scenario, where dedicated policy action is taken to address these goals. The Faster Transition Scenario binds the energy sector to a cumulative CO_2 budget of 790 Gt through 2100 and assumes that energy-related CO_2 emissions cannot drop below net-zero at any point in time. This could increase the chances of holding temperature rise to "well below 2 °C" as mentioned in the Paris Agreement. However, the outcome would depend on progress outside the energy sector, as well as requiring a faster energy sector transition than in the Sustainable Development Scenario: by 2040, energy-related emissions would drop to around 13 Gt.

An energy sector transition of such exceptional scope, depth and speed would require more stringent action than in the Sustainable Development Scenario. Unlike in the Sustainable Development Scenario, it would require the introduction of CO_2 prices for the power and industry sectors in all countries from 2020, the level rising to $170 per tonne of CO_2 in 2040.[22] Fossil-fuel subsidies would need to be removed by 2025, much earlier than in the Sustainable Development Scenario. Yet, these measures alone would not be sufficient. There would need to be further co-ordinated decarbonisation policy efforts across all sectors, partly to ensure the market uptake of technologies that are currently only at the stage of RD&D. The additional effort would be largest in end-use sectors. For example, by 2040, around a quarter of the truck fleet would need to be electric (compared to less than 1% in the Sustainable Development Scenario), which would require a large number of motorways to be equipped with electrified overhead (catenary) lines, since batteries alone struggle to support long-haul journeys.[23] Wider deployment of CCS would be needed in the industry sector in order to capture 19 Gt of energy and process-related CO_2 emissions from industry through 2040 (compared with 13 Gt in the Sustainable Development Scenario), and widespread improvements achieved in efficiency in the use of materials, including through increasing recycling and light-weighting. In the buildings sector, the entire existing building stock would need to be retrofitted by the middle of this century.

An energy sector transition made at the pace of the Faster Transition Scenario would require faster and higher deployment of low-carbon technologies than in the Sustainable Development Scenario. For example, by 2040, more than half of the cars on the road

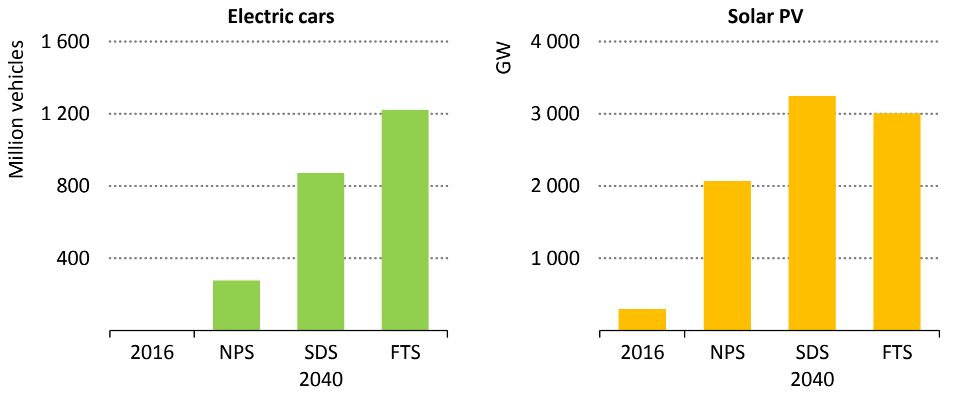
21. In the corresponding report, the scenario was referred to as "66% 2 °C Scenario". We change the name here for simplicity and accuracy of reporting; whether or not this scenario reaches 2 °C by 2100 with a 66% probability ultimately depends on the degree to which action is taken outside the energy sector, as outlined in the discussion of the CO_2 budget in the respective study.

22. See Chapter 1 for the corresponding assumptions in the Sustainable Development Scenario.

23. The use of hydrogen-fuelled trucks could be a viable alternative, depending on future technology progress.

would need to be electric (Figure 3.22). But there is no one-to-one relationship between the degree and pace of low-carbon technology deployment and the pace of the energy transition in the Faster Transition Scenario, compared with the Sustainable Development Scenario. The simultaneous achievement of climate, air pollution and energy access goals favours the use of distributed low-carbon technologies, such as solar PV, over central solutions, such as nuclear or CCS (Box 3.3). The result is that deployment of solar PV in the Sustainable Development Scenario is higher than that achieved in the Faster Transition Scenario, as a result of broader deployment of centralised generation options in the latter.

Figure 3.22 ▹ Deployment levels of electric cars and solar PV by scenario

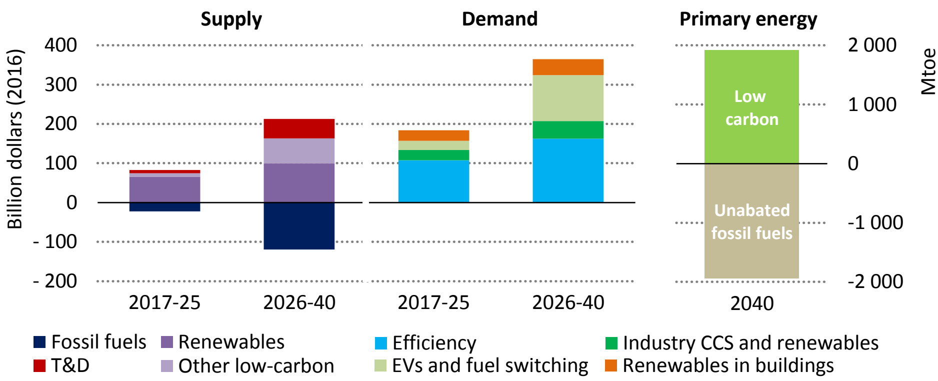


The deployment of electric cars and solar PV rises with stronger policy ambition; but pursuit of multiple policy goals leads to higher use of decentralised power generation technologies in the Sustainable Development Scenario

Note: NPS = New Policies Scenario; SDS = Sustainable Development Scenario; FTS = Faster Transition Scenario.

The investment requirements through 2040 of a faster energy sector transition would be higher than in the Sustainable Development Scenario, in particular in end-use sectors; an additional $6 trillion would need to be invested in decarbonising end-use sectors over the projection period. Besides additional investments in energy efficiency, much of the additional investment would be needed to achieve a switch to low-carbon fuels, including increasing the number of electric cars and trucks, additional direct use of renewables for heat production in the buildings and industry sectors, and additional CCS in the industry sector. One effect of this course would be a further reduction in fossil-fuel supply investments by around $1.8 trillion through 2040, relative to the Sustainable Development Scenario.

Figure 3.23 ▷ Additional average annual investment needs and changes in energy demand in the Faster Transition Scenario relative to the Sustainable Development Scenario



Additional investment needs in end-use sectors for a faster low-carbon energy sector transition outweigh the additional savings from lower fossil-fuel supply investments

Note: T&D = transmission and distribution; EVs = electric vehicles; CCS = carbon capture and storage.

Outlook for oil

A game of two halves

Highlights

- Oil markets in the New Policies Scenario go through two distinct phases to 2040. In the period to 2025, fuel efficiency policies, which at present cover 80% of global passenger car sales but only 50% of global truck sales, together with a rapidly growing fleet of electric vehicles, have an impact on demand but are insufficient to outweigh the near-term stimulus from low prices. Production growth is dominated by non-OPEC countries, particularly the United States, which accounts for 80% of the net increase in oil supply to 2025.
- After 2025, the rise in global oil demand slows markedly. Continued growth in petrochemicals (demand for high-value chemicals rises by 60% between 2016 and 2040), road freight, aviation and shipping is partially offset by declining oil use for passenger cars: the global car fleet doubles between 2016 and 2040 but becomes steadily more efficient and there are almost 280 million electric cars on the road in 2040. On the supply side, the market becomes more reliant on OPEC countries to balance the market post-2025, as US output plateaus and then falls back.
- The New Policies Scenario is characterised by steady upward pressure on the oil price, which reaches \$83/barrel by 2025. But there is uncertainty about underlying assumptions. Estimates of US tight oil resources have been revised upwards and there could be further surprises ahead. Countries could step up policy support for electric vehicles, reducing their costs more quickly. A Low Oil Price Case, with a price below \$70/barrel to 2040, is based on more extensive US tight oil resources, faster upstream technology improvements and more rapid uptake of electric cars.
- The fall in the oil price since 2014 has lowered upstream costs, as slack in the supply and service chains has been accompanied by a redesign and simplification of projects awaiting final approval. It is likely to be difficult to maintain all these cost reductions, especially in the rising demand environment of the New Policies Scenario: the extent to which it proves possible to do so is one of the key uncertainties for the future price of oil. Even if cost reductions are maintained, a shortfall of new conventional projects remains a substantial risk to the supply-demand balance in the early 2020s.
- Traditional patterns of global oil trade are undergoing a major upheaval. Soaring domestic production makes the United States a net oil exporter by the late 2020s. Middle East output continues to grow but only a small part becomes available for export due to the growth of domestic consumption and refining. Crude oil imports to Asia grow by 9 mb/d between 2016 and 2040, drawing in available supply from across the globe. The changing patterns of oil trade, production and consumption imply the need for a major reappraisal of how best to ensure oil security.

4.1 Recent market and policy developments

Oil markets are still adapting to the changes set in motion by the extended period of high prices that fostered the emergence of tight oil in the United States. When prices started falling in 2014, the decision by the Organization of Petroleum Exporting Countries (OPEC) to retreat from its traditional role as a market manager was an attempt to force a new balance on markets by constraining higher cost supply. Yet the US tight oil industry avoided the blow by morphing into a leaner, more agile version of its former self; it has since proved remarkably resilient to lower prices.

Many of the longer term implications of this tumultuous period in oil markets are only dimly visible through the dust thrown up by recent developments. We reflect this uncertainty in our modelling of a Low Oil Price Case (Spotlight) alongside our regular scenarios. One indicator that could have a major impact on future trends is the fall in global capital expenditure on new oil and gas projects. Shale investment is bouncing back in 2017, but elsewhere upstream spending remains in the doldrums: oil and gas upstream expenditure in 2017 is expected to be around $440 billion, nearly 45% lower than the historic high in 2014. Companies have been forced to reassess their approach to new developments, with many shifting investment towards projects with shorter payback periods and redoubling their efforts to reduce costs (which have offset some of the headline reduction in investment). Whether these are short-term or structural changes in industry behaviour, and for how long a surge in US tight oil supplies can compensate for a slow pace of growth elsewhere, are key issues explored in this year's *Outlook*.

Much attention has been paid to the long-term prospects of a slowdown and possible peak in global oil demand, particularly in the light of the Paris Agreement. Yet in the meantime, the period of low prices has underpinned robust demand growth, with demand up by 2 million barrels per day (mb/d) in 2015 and by a further 1.3 mb/d in 2016. How oil demand evolves from here, and the prospects of a peak in demand, will be determined by a variety of factors including oil prices, the economic transition underway in major demand centres (most notably China), the pace of fossil-fuel subsidy reform (subsidies for oil consumption fell to just over $100 billion worldwide in 2016, a near 25% reduction on 2015 levels), and the speed at which disruptive technology and business models emerge in the transport sector. Prospects for the two most stubborn sources of oil demand growth, petrochemicals and road freight, are examined in detail in this chapter.

Despite the boom in domestic oil production, the United States has remained a large net importer of oil. However, exports soared to over 0.9 mb/d in the first-half of 2017 in the wake of the lifting of the 40-year old ban in the United States on crude oil exports in late 2015. The US-led transformation of North America's oil trade position is one of a number of important developments that look set to change dramatically the nature and direction of oil flows around the world. Others include the build-up of refining capacity in the Middle East, and the relentless rise in Asia's appetite for oil imports. These changes have broad repercussions for the oil security of importing and exporting countries. The configuration of international trade in crude oil and oil products is therefore a topic of special analysis.

4.2 Trends by scenario

4.2.1 Market dynamics to 2025

It is difficult to plot a smooth pathway for oil markets to 2025. In the immediate future, the oil market looks well supplied. Tight oil output in the United States has resumed growth and – if it rises as projected in the New Policies Scenario to 2025 – the increase between 2010 and 2025 would match the largest sustained rise in production ever seen in an individual country, which was in Saudi Arabia from the late 1960s to the 1980s. At the same time, long-lead time projects that were approved before the drop in the oil price continue to come on stream. In Brazil, for example, despite numerous challenges, new production systems in its prolific pre-salt area are expected to add around 1 mb/d of new production by 2025. Yet there are clouds on the horizon. The impact of the near-record lows of new conventional oil projects receiving approval in recent years has yet to be fully seen. The observed declines in currently producing conventional fields mean that around 2.5 mb/d production is lost from the global oil balance every year. Growth in US tight oil may offset much of this decline for some years to come, but it could also keep prices at a level that inhibits the development of projects with longer lead times elsewhere. The *World Energy Outlook-2016* (*WEO-2016*) warned of the dangers of a prolonged period of suppressed conventional investments leading to a possible shortage of supply in the future. This warning remains as relevant today (see Chapter 2). Although the extent of US tight oil resources is uncertain (an issue explored in our Low Oil Price Case), this element of global supply cannot increase indefinitely and, when it slows, new projects will need to be ready to keep the market from tightening abruptly.

Developments on the demand side could offer some respite from the risk of a tightening oil market. In the New Policies Scenario, the average pace of growth in oil use in the coming years is around half the level seen over the past 15 years. Yet there are few signs of a shift in direction that would bring an early peak in global demand. Low prices have stimulated a rebound in demand in many regions and delayed in a number of places the date by which efficiency targets are assumed to be met; the downward revision of prices, relative to the *WEO-2016*, has also pushed up the rate of oil demand growth to 2025. There is a clear distinction in this context between many advanced economies where demand is already in structural decline, and developing economies (notably India), where growth remains robust. Reforms to fossil-fuel subsidies – assuming that they are sustained once prices start to rebound – curb the pace of growth in Latin America, Africa and the Middle East, but demand to 2025 still rises in these regions by 2 mb/d.

On the trade front, growth in the volume of crude oil made available to the international market in the coming years comes more from non-OPEC exporters, such as Brazil and Canada, than from OPEC countries. Members of OPEC have been expanding refining capacity domestically and so consume rising volumes of crude oil at home. Crude oil volumes that are exported from the Middle East are increasingly redirected away from traditional routes (to western refineries) towards Asian refiners. However, this is not enough to satisfy the appetite of Asian refiners, who increasingly draw in additional crude oil from Eurasia, Latin America and Africa.

4.2.2 Long-term scenarios to 2040

In the Current Policies Scenario, oil demand grows on average by 1 mb/d every year to 2040,[1] a similar pace to historic levels of growth, with demand surpassing 100 mb/d shortly after 2020 (Table 4.1). This scenario excludes policy ambitions that have yet to be implemented and demand growth exhibits little slowdown even as prices continue to rise. The rate of demand growth is slightly faster than in the corresponding scenario in the *WEO-2016*, and as a result global demand is around 2 mb/d higher by 2040. This is due to the lower oil price in this year's scenario and because we have made an upward revision to demand from road freight as a result of detailed new analysis on this topic (IEA, 2017a).

Growth is led by a near 20 mb/d increase in demand in the transportation sector. There are over 100 million passenger cars and more than 15 million freight vehicles sold on average every year to 2040 in the Current Policies Scenario. Without any tightening of vehicle fuel-economy standards beyond what is already on the statute books, and with limited growth in sales of electric vehicles (EVs), this leads to an upsurge in demand for oil in road transportation. This is most pronounced in China and India, in which a third of new passenger cars and a quarter of new freight vehicles are sold. As a result, by 2040, China and India account for a quarter of global oil demand (up from 17% today). On the supply side, OPEC increases production in the Current Policies Scenario by some 14 mb/d between 2016 and 2040, meeting over half of the increase in global demand. Brazil registers growth of nearly 4 mb/d over the same period, the largest increase by any country, as higher prices stimulate significant levels of investment in its resource-rich pre-salt reservoirs.

The New Policies Scenario includes an assessment of the likely impact of announced policy measures and targets, and this puts oil demand on a different course. In this scenario, the annual increase in oil demand to 2040 averages just under 0.5 mb/d, half of the level in the Current Policies Scenario, with oil demand surpassing 100 mb/d in 2025. Differences are less pronounced over the next five years (during which annual demand grows by 0.9 mb/d in the New Policies Scenario versus 1.2 mb/d in the Current Policies Scenario), but the divergence widens with time. The near-term differences relate to variations in the impact of fuel-economy standards for cars and trucks in China, the European Union and the United States; different levels of global fossil-fuel trade (affecting oil demand for shipping); and the effects on consumption of planned fossil-fuel subsidy reforms (such as for liquefied petroleum gas [LPG] in China). The longer term differences include not only efficiency and pricing policies but also the more rapid growth of alternative fuels and technologies in the New Policies Scenario, especially for passenger vehicles. Compared with the Current

1. References to oil demand exclude any contribution from biofuels, which are only included when referring to "total liquids demand".

Policies Scenario, the 13.5 mb/d difference in production in 2040 is absorbed mainly by lower output from the Middle East, Russia, Canada and Brazil.

As described in Chapter 1, the New Policies Scenario is characterised by steady upward pressure on the oil price, which reaches $83/barrel by 2025 and $111/barrel in 2040. Two of the key reasons for this relate to our view on the outlook for tight oil and for electric vehicles. The projected increases in oil supply engendered by US tight oil have a huge impact on the market, especially in the first half of our *Outlook* period, but these increases are not large enough for effects to be sustained all the way through to 2040. The projected changes on the demand side through the rise of EVs, based on the cost dynamics and policy support that are visible today, are similarly impressive but do not come through early enough or at the scale required to reverse the upward momentum in oil demand. However, we cannot rule out even larger and more rapid impacts in these areas; a different set of assumptions for tight oil and electric mobility are two of the pillars on which we construct a Low Oil Price Case (Spotlight).

Table 4.1 ▻ Oil and total liquids demand and supply by scenario (mb/d)

			New Policies		Current Policies		Sustainable Development	
	2000	2016	2025	2040	2025	2040	2025	2040
Road transport	30.1	40.7	43.0	44.0	45.1	52.7	39.7	25.9
Aviation and navigation	8.3	11.0	12.6	15.7	13.3	17.9	10.2	8.4
Industry & petrochemicals	14.4	17.4	21.1	23.6	21.2	24.1	20.5	21.6
Buildings and power	13.8	13.0	11.4	9.5	12.0	10.8	10.5	7.0
Other	10.0	11.7	12.2	12.1	12.5	13.3	11.5	10.0
World oil demand	**76.7**	**93.9**	**100.3**	**104.9**	**104.1**	**118.8**	**92.4**	**72.9**
Share of Asia Pacific	*25%*	*32%*	*35%*	*37%*	*35%*	*37%*	*36%*	*40%*
World biofuels	0.2	1.7	2.5	4.1	2.2	3.2	4.0	7.4
World liquids demand	**76.9**	**95.5**	**102.8**	**109.1**	**106.3**	**122.1**	**96.5**	**80.3**
Conventional crude oil	64.8	67.6	64.6	64.1	66.8	73.2	59.0	43.9
Tight oil	-	4.5	9.0	9.2	9.4	9.8	8.1	6.4
Natural gas liquids	9.0	16.2	18.5	20.8	19.3	22.7	17.7	15.9
Extra-heavy oil and bitumen	0.8	3.3	4.4	5.7	4.6	6.9	4.1	3.4
Other production	0.5	0.7	1.3	2.0	1.4	2.7	1.2	1.3
World oil production	**75.2**	**92.4**	**97.8**	**101.9**	**101.4**	**115.4**	**90.1**	**70.8**
Processing gains	1.8	2.3	2.5	3.1	2.6	3.5	2.3	2.1
World oil supply	**77.0**	**94.6**	**100.3**	**104.9**	**104.1**	**118.8**	**92.4**	**72.9**
Oil price ($2016/barrel)	**38**	**41**	**83**	**111**	**97**	**136**	**72**	**64**

Notes: Biofuels are expressed in energy-equivalent volumes of gasoline and diesel. Tight oil includes tight crude oil and condensate production except for the United States, which includes tight crude oil only (US tight condensate volumes are included in natural gas liquids). "Other production" includes coal-to-liquids, gas-to-liquids, additives and kerogen oil. Processing gains are volume increases that occur during crude oil refining. Differences between historical supply and demand volumes are due to changes in stocks. For more information on methodology and data issues, see *www.iea.org/weo/weomodel.*

SPOTLIGHT

What would it take for oil prices to stay "lower for longer"?

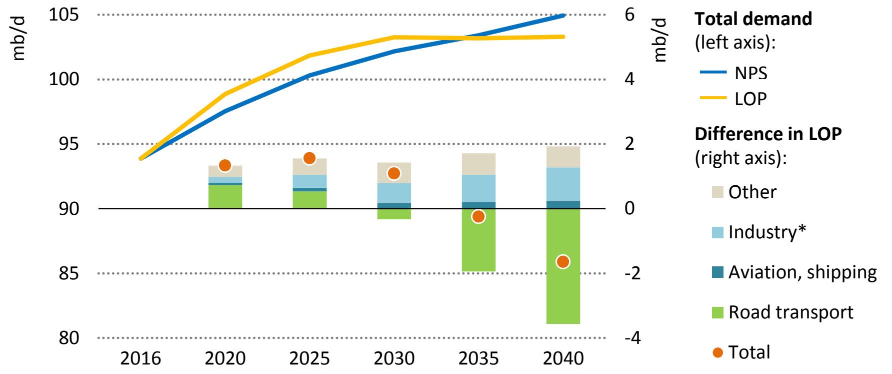
With each month seeming to raise new questions about the pace of the rebalancing process in oil markets, the idea that oil prices could stay "lower for longer" has become a constant theme of discussions. Two years on from the Low Oil Price Case that was examined in detail in the *WEO-2015*, we return to the question: under which circumstances could lower oil prices persist, not just for a year or two, but for a decade or more? There are many different factors that could come into play, but our modelling of a Low Oil Price Case in this year's *Outlook* is based on:

- A doubling in the estimated size of the resource base for US tight oil. The estimated size of this resource in the United States has already been revised up to 105 billion barrels for this *Outlook* (see section 4.3.2). Yet estimates are uncertain, especially for the Permian Basin in the southern United States: the Low Oil Price Case assumes a tight oil resource of 210 billion barrels, meaning that more oil can be produced at low cost.
- Accelerated technology learning across the upstream sector, reflecting the possibility that the widespread application of digital technologies (among other innovations) could keep a lid on upstream costs. A faster rate of technology learning than that already incorporated in the New Policies Scenario provides a stronger counterweight to the upward pressure on costs coming from the move to lower quality and more complex resources. This means that new fields can be developed at lower breakeven prices.
- A much more rapid switch to electric passenger cars, which would require a combination of technology gains and a step-change in policy support worldwide (not least to counter the additional edge that gasoline-fuelled vehicles would have in a lower oil price world). Whereas the New Policies Scenario includes a large ramp-up in the stock of electric cars to 280 million by 2040 (from 2 million today), the Low Oil Price Case anticipates a much steeper increase. By assuming more widespread policy intervention, including for infrastructure, and consumer acceptance, the electric passenger car fleet expands to close to 900 million by 2040, in line with the projections in the Sustainable Development Scenario.

With these assumptions, we find that the oil market can find a longer term equilibrium in the range of $50-70/barrel (in real terms).

In the Low Oil Price Case the story is mainly supply-driven until the mid-2020s, with more US tight oil surging into the market in the event of any upswing in prices. This keeps the average price in the low $50s per barrel, even though global consumption is higher than in the New Policies Scenario (Figure 4.1) as consumers take advantage of the lower prices. From the late 2020s the dynamics change as rapid growth in the electric car fleet starts to make a significant dent in the trajectory for oil demand. Oil use in passenger vehicles peaks in the early 2020s and oil use for the road transport sector as a whole peaks around the late 2020s (even though oil use for trucks continues to grow). Global oil demand plateaus at around 103 mb/d: the decline in road transport demand is offset by rising industrial oil use, notably for petrochemical feedstocks, and by shipping and aviation (oil use continues to decline in the residential sector and from power generation albeit at a slower pace than in the New Policies Scenario).

Figure 4.1 ▷ Difference in oil demand by sector in the Low Oil Price Case relative to the New Policies Scenario

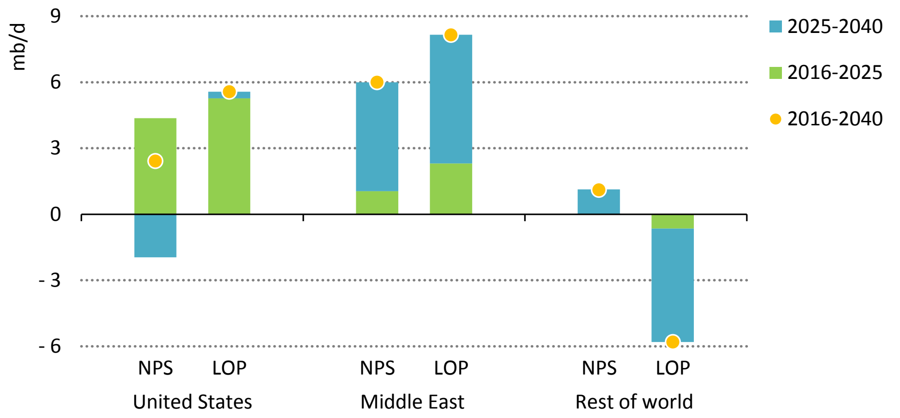


Rapid expansion of the electric car fleet pulls down oil use for road transport, but is not enough to lead to an overall peak in oil demand

* Includes demand for feedstocks. Note: NPS = New Policies Scenario; LOP = Low Oil Price Case.

A flattening in global consumption eases pressure on the supply side to an extent, but there is still a constant need to develop new resources in order to compensate for declining production at existing fields. The United States can take part of the strain and, buoyed by tight oil, US total production remains consistently above 18 mb/d through to 2040, with net exports of over 4 mb/d by the late 2030s. However, maintaining a price in the $50-70/barrel range also requires higher output from the world's largest source of low-cost oil, the Middle East (even with accelerated technology learning, output from the rest of the world goes into long-term decline at these price levels). Middle East production is consistently higher in the Low Oil Price Case than in the New Policies Scenario (Figure 4.2), and this implies at least a partial return by OPEC countries to a strategy prioritising market share over active market management. The Low Oil Price Case also makes the important assumption that key producers are able to weather the fiscal and social strains entailed by a long-term low-price outcome.

Figure 4.2 ▷ **Changes in oil production by region in the New Policies Scenario and Low Oil Price Case**



A larger tight oil resource keeps US production buoyant, but maintaining a Low Oil Price Case to 2040 also requires higher output from the Middle East

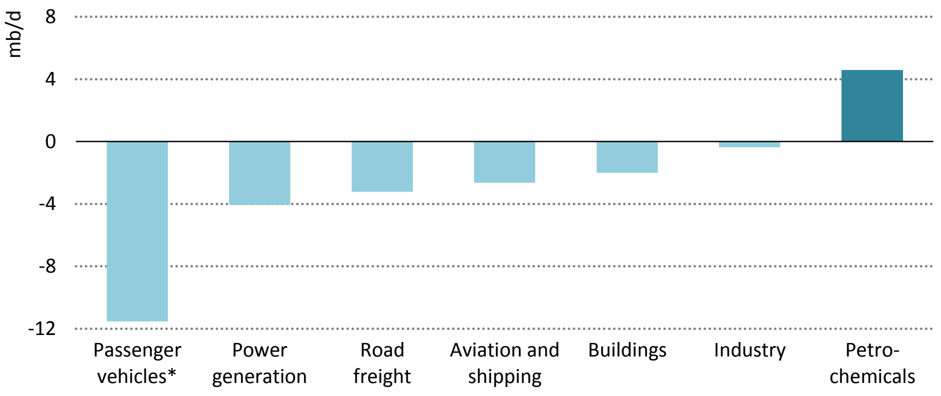
Note: NPS = New Policies Scenario; LOP = Low Oil Price Case.

The supply and demand revolutions described in the Low Oil Price Case cannot be excluded, but they require strong assumptions, not least because the lower prices they engender make each revolution more difficult. Sustaining ample supply over the long term is hard in a world in which the capital available for investment in new projects is continually squeezed. Likewise, reaching a peak in global demand is much tougher when consumers have fewer economic incentives to make the switch away from oil or to use it more efficiently.

The Sustainable Development Scenario starts from a different set of assumptions (see Chapter 3) and these imply a very different future for oil markets and the oil industry. Oil demand in the Sustainable Development Scenario peaks at just over 95 mb/d around 2020 and declines at an increasing rate in subsequent years so that during the 2030s it is falling by over 1 mb/d each year. The largest decrease from current levels is in the transport sector (Figure 4.3), with the number of electric cars on the road in the Sustainable Development Scenario close to 900 million in 2040 (as in the Low Oil Price Case above): these electric cars avoid 9.2 mb/d of oil consumption in 2040. However setting oil markets onto a pathway consistent with the Paris Agreement climate objectives and the other objectives of the Sustainable Development Scenario will require more than electric cars. It also requires the implementation of stringent efficiency standards: these measures avoid 14 mb/d oil consumption from passenger vehicles (including cars, two/three wheelers and buses) in

2040. There are also enhanced efforts to decarbonise freight transport through systemic improvements in road freight operations and logistics, and a shift towards the use of alternative fuels and vehicles. The use of biofuels also expands at a rapid pace, reducing the use of oil in the aviation and maritime sectors by 3.8 mb/d in 2040. Despite these various changes, oil still accounts for just over 60% of total transport demand in 2040 in the Sustainable Development Scenario (in energy-equivalent terms), compared with 92% today. The slow turnover of the vehicle fleet and the lack of substitutes available at scale in some of the demand sectors are the principal reasons why the reduction is not larger.

Figure 4.3 ▷ Change in global oil demand by sector in the Sustainable Development Scenario, 2016-2040



Oil demand falls in all sectors in the Sustainable Development Scenario except petrochemicals where growth is largely the same as the New Policies Scenario

* Includes passenger cars, two/three wheelers and buses.

Achieving universal energy access in the Sustainable Development Scenario has important implications on demand for LPG. Our latest analysis shows that 1.1 billion people currently lack access to electricity and that 2.8 billion rely on traditional biomass for cooking. The use of LPG is a key mechanism (although by no means the only one) for eliminating the traditional use of biomass in inefficient cookstoves. As a result, residential LPG demand in the Sustainable Development Scenario stays at around 4 mb/d through to 2040, 1 mb/d higher than last year's *Outlook* in the 450 Scenario. Yet meeting this level of LPG demand will mean overcoming various challenges (Box 4.1).

Elsewhere, there are intensified efforts to move away from oil use in power generation, most notably in the Middle East and Japan, where it is swiftly replaced by renewables. The only sector to exhibit growth in oil demand in the Sustainable Development Scenario is petrochemicals, in which consumption is largely the same as in the New Policies Scenario (see petrochemicals in section 4.3.1).

Box 4.1 ▷ LPG: fuel for cleaner cooking

In the Sustainable Development Scenario, LPG is one of only three oil products for which demand increases between 2016 and 2040 (the others being naphtha and ethane). LPG is usually supplied from refineries or by fractionating natural gas liquids (NGLs). Unlike other products, for which increased demand tends to trigger a supply response, the supply of LPG is somewhat different, and this poses challenges to satisfy the growing need for LPG for clean cooking. NGLs are a by-product of natural gas production, so their supply tends to be determined more by demand for natural gas than for the liquids. When produced by refineries, LPG accounts for less than 10% of refinery outputs, so refiners are unlikely to raise utilisation rates or make investments just to increase the production of LPG, as this would generate a huge surplus of other products.

Growing LPG demand could motivate refiners to increase LPG yields and upstream companies to pursue liquid-rich plays, but this alone would not be sufficient to meet the levels of LPG required to achieve universal access to clean cooking. If enough LPG is to be available to achieve this objective, some of the LPG used in other sectors such as petrochemicals and industry will need to be redirected towards the residential sector. This means that policy measures to support clean cooking need to be sufficiently strong to encourage petrochemical and other industrial firms to switch away from LPG to other feedstocks and products. Ensuring that LPG subsidies are targeted towards the neediest will also be essential.

The challenges are not just on the production side. Developing economies in Asia and Africa represent the bulk of the growth in residential LPG demand, but these regions do not have sufficient refining capacity or indigenous NGLs production to meet their needs. A large share of demand therefore needs to be met by imports from other regions, notably the Middle East and the United States. In the Sustainable Development Scenario, the result is that developing economies in Asia increase their reliance on LPG imports and Africa as a whole turns into a net importer of LPG. Growing reliance on imports requires adequate infrastructure and this poses additional challenges, especially for Africa where there are few existing import terminals and storage facilities. Policy efforts to promote LPG therefore need to consider the broader investment requirements to develop the LPG supply chain as well as the direct investment needs for LPG cookstoves.

4.3 A closer look at the New Policies Scenario

4.3.1 Demand

Regional trends

Two distinct phases can be identified in the trajectory for global oil demand in the New Policies Scenario (Table 4.2). Between 2016 and 2025, average annual growth in demand exceeds 0.7 mb/d: it then slows considerably so that between 2025 and 2040 the average increase in demand is just over 0.3 mb/d. Nevertheless, there is no peak in demand before 2040 and demand in 2040 reaches 105 mb/d. This is around 1.4 mb/d higher than the level in the *WEO-2016*.

Table 4.2 ▷ Oil demand by region in the New Policies Scenario (mb/d)

							2016-2040	
	2000	2016	2025	2030	2035	2040	Change	CAAGR
North America	22.9	22.3	21.8	20.5	19.0	18.0	-4.3	-0.9%
United States	18.9	18.1	17.5	16.3	14.8	13.8	-4.3	-1.1%
Central & South America	4.5	5.9	6.2	6.3	6.5	6.7	0.7	0.5%
Brazil	1.9	2.4	2.5	2.7	2.8	2.9	0.5	0.8%
Europe	14.9	13.0	11.3	10.3	9.4	8.7	-4.3	-1.7%
European Union	13.1	11.1	9.2	8.2	7.2	6.5	-4.6	-2.2%
Africa	2.2	3.9	4.6	5.1	5.6	6.2	2.3	2.0%
South Africa	0.4	0.6	0.6	0.7	0.7	0.8	0.2	1.3%
Middle East	4.3	7.6	8.6	9.1	9.9	10.7	3.1	1.4%
Eurasia	3.1	3.9	4.3	4.4	4.4	4.4	0.5	0.6%
Russia	2.6	3.2	3.4	3.4	3.4	3.3	0.2	0.2%
Asia Pacific	19.4	29.6	34.8	37.0	38.3	39.2	9.6	1.2%
China	4.7	11.5	14.5	15.4	15.5	15.5	4.1	1.3%
India	2.3	4.4	6.3	7.5	8.7	9.7	5.2	3.3%
Japan	5.1	3.7	3.0	2.7	2.4	2.1	-1.6	-2.3%
Southeast Asia	3.1	4.7	5.8	6.2	6.4	6.6	1.8	1.4%
Bunkers	5.4	7.7	8.8	9.5	10.3	11.1	3.5	1.6%
World oil	**76.7**	**93.9**	**100.3**	**102.2**	**103.4**	**104.9**	**11.1**	**0.5%**
World biofuels	0.2	1.7	2.5	3.1	3.6	4.1	2.5	3.9%
World liquids	**76.9**	**95.5**	**102.8**	**105.3**	**107.0**	**109.1**	**13.5**	**0.6%**

Notes: CAAGR = Compound average annual growth rate. Bunkers include international marine and aviation fuels. Biofuels are expressed in energy equivalent volumes of gasoline and diesel.

Oil demand in advanced economies in North America, Europe and the Asia Pacific region grew by just under 0.8 mb/d between 2014 and 2016. This trend, largely a reaction to the plunge in oil prices, is not sustained in the New Policies Scenario, and demand in these countries contracts by 11 mb/d between 2016 and 2040. Nearly 60% of this drop results from reductions in oil use in passenger cars: there are over 770 million passenger cars on the road in these countries by 2040 (20% more than in 2016), but with the implementation of fuel-economy standards and with EVs becoming increasingly established, the fleet in 2040 is on average twice as efficient as it is today.

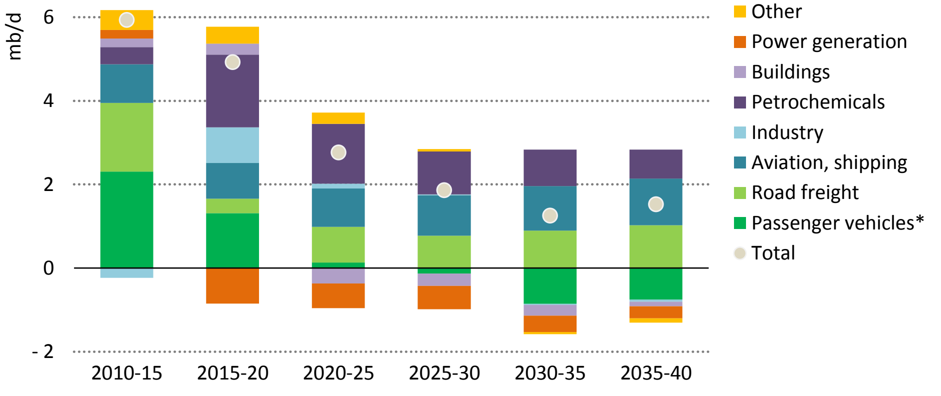
The long-term decrease in oil demand in advanced economies is more than offset by a near 12 mb/d growth in developing economies in the Asia Pacific region. India alone provides nearly half of this growth, more than doubling oil consumption between 2016 and 2040: the number of cars per household in India jumps by a factor of five between 2016 and

2040. Demand in China has not yet reached the end of its period of robust growth, but this is set to slow over the horizon of the New Policies Scenario. Of the 4 mb/d growth in China between 2016 and 2040, three-quarters is set to occur in the next ten years, and by the late 2020s annual oil demand additions in India surpass that of China. Elsewhere, Africa registers the second-largest pace of growth (after India) over the course of the New Policies Scenario, while oil consumption in the Middle East overtakes the European Union by the late 2020s, a clear signal of the shifting geography of demand envisaged in this scenario.

Sectoral trends

There is a wide divergence in the prospects for oil demand across sectors (Figure 4.4). Oil-fired power generation, which today provides a third of annual electricity generation in the Middle East, declines throughout the New Policies Scenario. Oil use in buildings remains largely confined to the residential sector where demand declines from 2020 onwards. At present, a large part of this demand takes place in countries in developing Asia and sub-Saharan Africa in the form of LPG for cooking purposes and this use grows over the course of the New Policies Scenario. This is more than offset by declines elsewhere, as consumers switch to more efficient oil boilers, or away from oil altogether.

Figure 4.4 ▷ Change in global oil demand by sector in the New Policies Scenario



Petrochemicals, aviation and shipping, and road freight account for the bulk of the growth in oil demand, offsetting declines in other sectors

* Includes passenger cars, two/three wheelers and buses.

The global electric car fleet expands rapidly in the New Policies Scenario: the number of electric cars on the road grows by over 50% each year to 2020, and by 2025 there are nearly 50 million electric cars on the road. Up to 2025, however, the impact of electric cars on oil consumption is relatively muted – less than 0.7 mb/d is displaced in 2025. After

2025, as electric cars continue to grow in number, they have an increasing impact on oil demand. By 2040 there are almost 280 million electric cars on the road, around 15% of the car fleet, and they displace around 2.5 mb/d of oil demand. This is a significant upward revision to the number in the *WEO-2016* (which projected 150 million electric cars in 2040), reflecting the increasing number of policies put in place to promote electric vehicles or reduce the use of conventional cars in order to address air pollution and reduce carbon-dioxide (CO_2) emissions, both at national and local levels (Table 4.3). China maintains its current leadership of electric car sales throughout the New Policies Scenario, backed by strong policy support. In 2040, almost 50% of electric cars in the world are in China. The announced phase-out of conventional engines in France, Netherlands and United Kingdom means that 40% of cars sold in the European Union in 2040 are electric in the New Policies Scenario, the highest share in the world.

Table 4.3 ▷ Selected recent initiatives for electric mobility

Country	Direct electric vehicle policy incentives and announcements
China	5 million electric cars on the road by 2020 and 20% of electric cars in total sales by 2025. Declared intent to move to full phase-out of gasoline and diesel car sales; details to be announced.
France	Full phase-out of gasoline and diesel car sales by 2040.
Finland	250 000 EV stock by 2030.
India	Declared intent to move to full electrification of vehicle sales by 2030; details to be announced.
Malaysia	100 000 electric cars and 2 000 electric buses on the road by 2030, plus 125 000 charging stations across the country.
Netherlands	All new cars sold to be zero emissions by 2030.
Norway	All new cars, light vans and urban buses to be zero emissions by 2025. All new heavy vans, 75% of new intercity buses and 50% of new trucks should be zero emissions vehicles by 2030.
Poland	1 million EV stock by 2025.
Thailand	1.2 million EV stock by 2030.
United Kingdom	Phase-out of gasoline and diesel car sales by 2040.
City	**Direct electric vehicle policy incentives and announcements**
Copenhagen	Carbon neutral public transport, 20-30% low-carbon light-duty vehicles and 30-40% low-carbon heavy-duty vehicles by 2025.
Dubai	10% of new car sales to be electric or hybrid by 2020. 10% of the car stock to be electric or hybrid by 2030.
London	Taxi and private hire vehicles fleet to be zero emissions by 2033. Bus fleet to be zero emissions by 2037. All vehicle sales to be zero emissions by 2040. Whole transport system to be zero emissions by 2050.
Los Angeles	10% of vehicles to be zero emissions by 2025 and 25% by 2035.
New York City	20% EV sales by 2025.
San Francisco	New residential, commercial, and municipal buildings to be able to charge electric vehicles in 20% of parking spaces.

The New Policies Scenario also sees a rapid rise in the number of electric vehicles (i.e. extending beyond cars to two/three wheelers and public vehicles). This is particularly the case in India where 20% of all passenger vehicles are electric by 2040, with a higher uptake than currently projected possible depending on how announced government targets will be implemented. The use of biofuels and natural gas in passenger vehicles also increase in importance, avoiding a further 4.7 mb/d of oil demand in 2040. It is, however, the fuel-efficiency standards implemented in the New Policies Scenarios that play the most important role in instigating the decline in oil consumption in passenger vehicles from the mid-2020s, displacing around 12 mb/d of potential oil demand in 2040 (see Chapter 7).

Despite the long-term declines in oil use for passenger vehicles, overall oil demand keeps rising in the New Policies Scenario. Consumption in the aviation sector increases by over 3 mb/d between 2016 and 2040 because of robust increases in travel demand, particularly in developing Asian economies, as well as the lack of readily available alternatives to oil in aviation. Oil use in shipping grows more slowly, but still registers a 1.4 mb/d increase to 2040. The use of heavy fuel oil, the mainstay of the shipping industry, has come under increased scrutiny in recent years over the release of sulfur-dioxide (SO_2) emissions, which can be damaging to health and the environment. In October 2016, the International Maritime Organization (IMO) announced plans to introduce a 0.5% cap on the sulfur content in marine fuels to be implemented from 2020 onwards (the sulfur content of heavy fuel oil is often as high as 3.5%).[2] To meet this goal, ship owners can decide whether to use low-sulfur fuels (diesel or low-sulfur fuel oil), switch to alternatives such as liquefied natural gas (LNG), or install scrubbers to lower the sulfur content of flue gas originating from the combustion of high sulfur fuels.

A combination of all three elements is used in the New Policies Scenario. Owners bringing their ships into compliance with the new regulation in the period to 2020 largely rely on the use of scrubbers or low-sulfur fuels. Some initially opt for diesel, whose share in shipping rises rapidly around 2020 from 30% to over 40%, before declining over time as an increasing number of scrubbers are installed. Some of the displaced heavy fuel oil around 2020 may find a home in power generation, but not all: this creates an oversupply and the possibility of a major drop in prices, which, if it happens, will help improve the economics of installing scrubbers. After this decline to 2020, the share of fuel oil in the maritime sector gradually rises to 60% in 2040 but remains lower than today's share of 70%. Over the longer term, LNG consumption grows in importance, with its consumption as a maritime fuel increasing from negligible levels today to nearly 60 bcm by 2040 (12% of maritime fuel consumption at that time).[3] SO_2 emissions from shipping fall by over 60% to 2040 as a result of these changes. However, CO_2 emissions rise by more than 40% over the same period as the cap on SO_2 emissions from ships is not matched by any firm policies or regulations to reduce other greenhouse-gas (GHG) emissions.

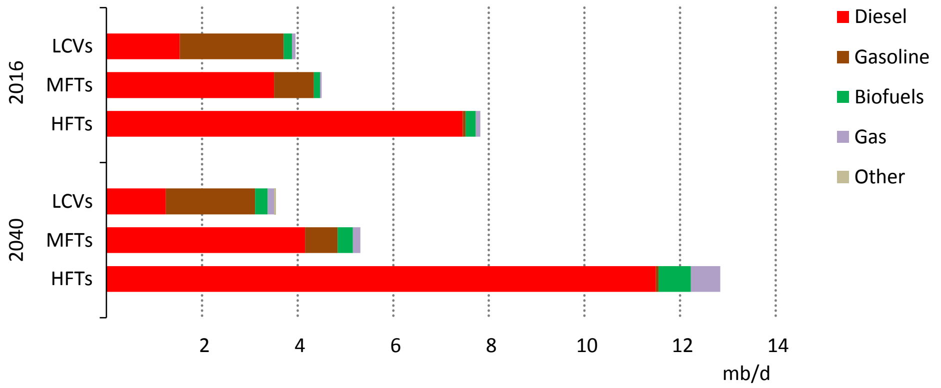
2. Regulations state that the sulfur content of fuel consumed is to be no more than 0.5%, but they allow for other means to reach equivalent levels, such as through scrubbers (IMO, 2008).

3. Excluding own use in LNG carriers.

Focus on road freight[4]

Trucks are a key enabler of economic activity: they deliver goods and commodities from their points of production to the industries that use or transform them and then onto their final points of sale. It is therefore unsurprising that economic growth and increases in road freight activity are closely correlated. The road freight sector has emerged as a key consumer of oil in recent decades and its significance continues to grow. Oil use by road freight vehicles accounts for just under 20% of world oil demand, roughly equal to that of the entire industry sector (including petrochemical feedstocks): only passenger vehicles have a larger share of the total. Road freight transport relies primarily on diesel, which accounts for around 80% of its total oil use. Road freight vehicles were responsible for around 60% of the net increase in global diesel demand since 2000, and make up around half of total diesel demand today. Future growth to 2040 is dominated by medium- and heavy-freight trucks, as oil demand from light commercial vehicles falls by 15% between 2016 and 2040 (Figure 4.5).

Figure 4.5 ▷ Global road freight fuel demand by vehicle category in the New Policies Scenario



Oil demand for road freight grows to 20 mb/d in 2040, stemming almost entirely from the strong growth in diesel demand for heavy-freight trucks

Note: LCVs = light commercial vehicles; MFTs = medium-freight trucks; HFTs = heavy-freight trucks.

The rapid increase in diesel demand for road freight witnessed over the past 15 years can be explained in part by the fact that policies to promote efficient road freight vehicles and operations lag behind those for cars. Standards to improve the fuel economy of cars cover more than 80% of global passenger car sales, while standards to improve the efficiency and emissions intensity of heavy-duty trucks have been adopted in only five national markets – Canada, China, India, Japan and United States – and cover only about 50% of vehicle

4. For a more detailed discussion, see *The Future of Trucks: Implications for Energy and the Environment* (IEA, 2017a).

sales (standards in India were announced in August 2017 and are incorporated in the New Policies Scenario). However, growing awareness of the need to promote vehicle efficiency technologies has recently given rise to more policy attention: the European Union, Mexico and Korea are at various stages of developing their own heavy-duty vehicle standards, with planned implementation dates over the coming five years.

In addition to fuel-economy standards, systematic improvements in road freight operations and logistics are also assumed in the New Policies Scenario, which help to curtail some oil demand growth as cargo-carrying vehicles are utilised more effectively (i.e. with increased loads), reducing the amount of travel needed.[5] Meanwhile a switch to alternative fuels, mainly to natural gas and biofuels, diversifies the fuel mix, effectively displacing 2.3 mb/d of oil by 2040, with growing interest in the potential for electrification focused mainly on light commercial vehicles. Natural gas gains ground primarily in China and the United States. Price differentials between oil and gas as well as clean air policies in these regions aid this switch, with truck carriers able to make use of a growing refuelling network. Despite these measures, oil demand for road freight in the New Policies Scenario still grows by 4 mb/d between 2016 and 2040. Mirroring historical trends in advanced economies, a growing share of freight is transported by road in developing economies, especially as highway infrastructure expands – the vast majority of this growth is met by diesel.

Focus on the petrochemical sector

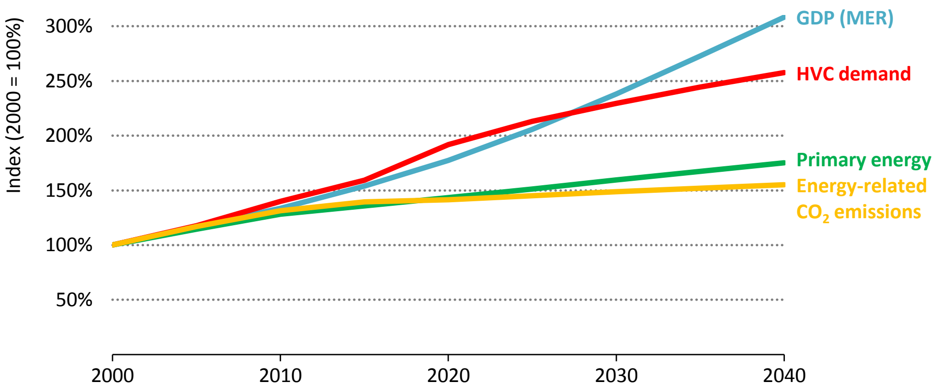
Petrochemicals, used to produce plastics, resins and fibres (among other products), have been an important part of the global economy for a number of decades. In recent years, growth in demand for petrochemicals has remained largely in line with gross domestic product (GDP), unlike primary energy demand or energy-related CO_2 emissions whose relationship with GDP has been loosening (Figure 4.6). In the New Policies Scenario, global demand for high-value chemicals (ethylene, propylene and aromatics) grows by 60% to 560 million tonnes between 2016 and 2040. The increase could be greater still if, for example, innovation in chemical products triggers further substitution away from other materials (metals, wood) or if a much higher number of EVs are sold (electric vehicles tend to require more plastic than conventional cars). China is at the centre of this increase due to robust growth in its overall manufacturing output as well as its gradual shift to a consumer-driven economy (which adds to demand for plastics both for products and for packaging). With other Asian countries following suit, Asia Pacific accounts for 60% of the petrochemicals demand growth between today and 2040.

Robust demand for petrochemicals implies a significant expansion in the consumption of oil products, and feedstock dynamics are therefore an important issue in this context. Ethylene, the most important chemical in the industry, is mostly produced using a steam cracking process that relies on naphtha, gas oil, LPG or ethane, but also through ethanol

5. Examples include the use of global positioning systems to optimise truck routing and driver training and the use of on-board, real-time feedback devices that monitor the on-road fuel economy of trucks.

dehydration or gasification processes using coal. Propylene is also produced using a steam cracking process or directly from the refining sector, while "on-purpose" technologies such as propane dehydrogenation (PDH) are becoming increasingly prevalent. Aromatics are produced by the catalytic reforming of naphtha in oil refineries and, to some extent, by steam cracking.

Figure 4.6 ▷ Global GDP, total primary energy demand, CO_2 emissions and chemicals demand trajectories in the New Policies Scenario



Demand for high-value chemicals tracks the trajectory of GDP more closely than primary energy demand and energy-related emissions

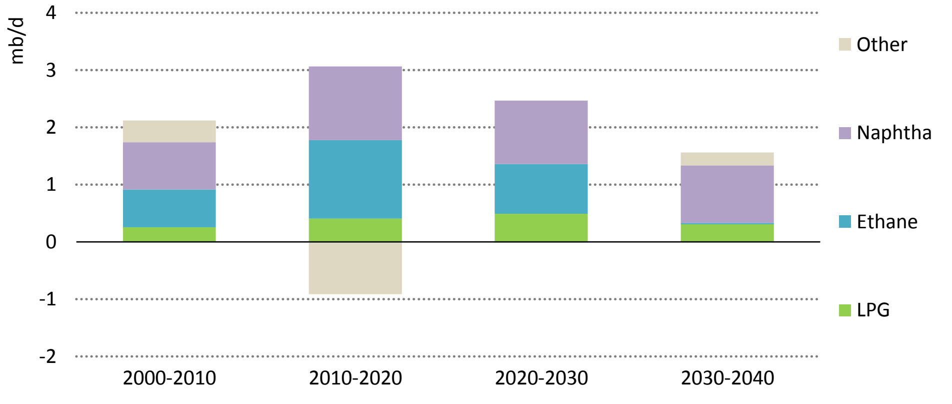
Note: HVC = high-value chemicals; MER = Market Exchange Rate.

Naphtha has traditionally been the dominant feedstock for petrochemical products. In 2000, naphtha accounted for nearly half of the feedstock inputs while ethane represented 19% (in volumetric terms). However, the dominance of naphtha started to be challenged when a number of ethane crackers in the Middle East came online in the late-2000s. These increased the share of ethane to 22% in 2010 at the expense of naphtha. Another emerging challenge to naphtha is now looming in the United States, where shale gas extraction (geared towards liquids-rich plays) has led to a glut of ethane, which has in turn led to a significant drop in ethane prices. With limited outlets for consumption or export, significant volumes of ethane that could have been produced were reinjected into the natural gas stream (often called "ethane rejection") as the economics did not favour full ethane recovery. This triggered a series of investments to build new ethane crackers and expand existing plants, many of which are expected to come online by the end of this decade.

As a result, around 13 million tonnes of new cracking capacity (a 45% increase on today's capacity) comes on stream in the United States during the period to 2025: this reinvigorates its petrochemical industry, where production has remained flat since 2000. Once constructed, these new crackers are likely to be positioned next to existing Middle Eastern ethane crackers in the ethylene production cost curve, pushing all other capacities to the higher end of the curve. This means that the new US crackers may be less affected by cyclicality in the industry (playing an analogous role to "baseload" generation in the power sector). Outside the United States, Iran is in the process of adding around 5 million tonnes of ethane cracking capacities to generate increased value from its rising gas production (although there is a risk of delays). Some European crackers are meanwhile investing in retrofits to increase feedstock flexibility in response to future uncertainties. With some new capacity also under construction in Russia, the share of ethane in petrochemical feedstocks globally rises to over 30% by 2025. The increased adoption of ethane as a feedstock in the New Policies Scenario leads to a shortfall in propylene production, resulting in the increased use of LPG through technologies such as PDH.[6]

Will ethane-based capacity continue to expand and dominate the global petrochemical industry over the long term? Although ethane crackers currently stand to benefit from a cost advantage over naphtha crackers elsewhere, further increases in ethane cracking capacity are likely to be constrained by ethane output, which (as in the case of LPG discussed in Box 4.1) cannot easily respond to signals from the demand side. With ethane consumption in the United States set to grow rapidly from 2017, and waterborne exports of ethane (to Europe and India) already underway, the market for ethane looks set to tighten over the next few years. In the New Policies Scenario, ethane supply reaches a plateau in the late 2020s and then starts to fall back, pushing up prices. Meanwhile, waning gasoline demand combined with excess refining capacity starts to drag down naphtha prices, reviving the share of naphtha in the longer term (Figure 4.7).

Figure 4.7 ▷ Change in global oil product demand for petrochemical feedstock in the New Policies Scenario



Ethane expands to the mid-2020s, but naphtha regains market share over the longer term

6. Compared to naphtha crackers, ethane crackers mostly yield ethylene and a minuscule amount of propylene (less than 5%), which necessitates an alternative way of meeting demand for propylene.

The pivot towards heavier feedstock is already visible in the Middle East. Ethane supply in the region has tightened in recent years (except in Iran), and the reduced availability of ethane has prompted a change in the design of recent expansions to use mixed feedstock (for example, ethane with naphtha or butane), raising the share of heavier feedstock consumption in the region. Saudi Arabia is also pursuing a project that converts crude oil directly to high-value chemicals in order to reduce its reliance on ethane feedstock.

The expansion of ethane-based capacities in the New Policies Scenario does not in any case completely eliminate new higher cost naphtha-based cracking capacity. Naphtha crackers hold some advantages over their ethane-based counterparts. They can produce a more diverse range of products, including propylene and aromatics, whereas ethane crackers are highly skewed towards ethylene production. Naphtha-based facilities therefore continue to be built in regions where demand is growing, notably in China and other developing economies in Asia.

In recent years, there have also been efforts to adopt non-oil based feedstock such as coal or biomass to produce petrochemical products. The most notable examples include coal-to-olefin (CTO) and methanol-to-olefin (MTO) processes,[7] which have made great strides in China. China started building CTO/MTO plants earlier this decade to take advantage of its low-cost domestic coal resources, with the aim of displacing higher cost naphtha crackers. At the end of 2016, CTO/MTO production capacity amounted to more than 10 million tonnes, equivalent to 21% of the country's olefin production. In the New Policies Scenario, CTO/MTO capacity in China continues to grow but at a slower pace, accounting for around a third of Chinese olefin production by 2040.

For CTOs, the combination of a drop in oil prices and a surge in coal prices has, for the time being, wiped out the cost advantage that projects once enjoyed over naphtha crackers. Other challenges remain as well, including: capital constraints, logistical complications, water stress, and the size of the carbon footprint of CTO projects. Nevertheless, these projects provide a way of monetising a surplus of coal, generating jobs in inland provinces, and offering flexibility to adjust the ethylene-to-propylene ratio (something most ethane crackers lack), which is why the 13th Five-Year Plan encourages the construction of new coal-based chemical plants. For MTOs, future prospects are highly dependent on the price of methanol. The recent spike in domestic methanol prices weighted heavily on the profitability of MTO plants and led many companies to delay or reconsider new investments. Several Chinese companies are building methanol plants in the United States with a view to exporting methanol to China, but whether they will contribute to the stabilisation of methanol prices remains to be seen.

The use of bio-based feedstock offers one potential alternative to oil demand. The success of bio-based chemicals will be largely determined by the cost competitiveness of the production process and by the future availability of biomass feedstock. There is currently

7. The CTO process converts coal to synthesis gas, then to methanol and finally to various olefin products whereas MTO directly converts methanol feedstock to olefin products.

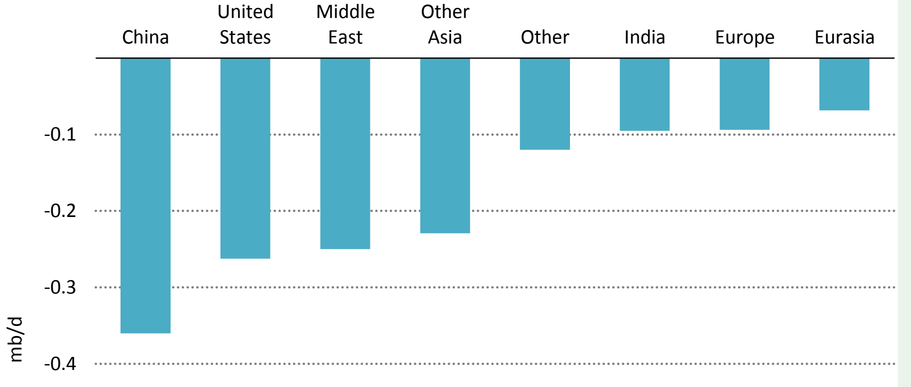
a considerable cost gap that bio-based processes need to close in order to be competitive, and it is hard to see this happening without technological advances or breakthroughs. Moreover, bio-based processes need to compete for feedstocks with other sectors where bioenergy can enjoy strong policy support such as transportation and (in the Sustainable Development Scenario) the production of heat and electricity. As a result, there is limited penetration of bio-based feedstock in the New Policies Scenario (and even in the Sustainable Development Scenario). However, deployment could be substantially higher if there were additional policy interventions beyond those currently in prospect.

With few substitution options away from oil available in the petrochemical industry, and with many of the easiest efficiency opportunities already captured over the past decade, global oil demand for feedstock increases from 11 mb/d today to 16 mb/d by 2040 in the New Policies Scenario. This is the largest increase in any sector and accounts for around half of the net increase in global oil demand over this period. In addition to further energy efficiency improvements, improving the efficiency of material use is an important complementary strategy in order to reduce oil consumption in the sector (Box 4.2).

Box 4.2 ▷ A material opportunity to improve global efficiency

Improving material efficiency means delivering the same material service with less overall production of materials (IEA, 2015). In the petrochemical sector, it can be achieved through reducing the weight of products ("light-weighting"), minimising yield losses in the production process, and reusing and recycling plastic products (Allwood and Cullen, 2012). These measures reduce the demand for plastics and thus reduce the demand for oil as a feedstock.

Figure 4.8 ▷ Potential additional impact of material efficiency improvements on oil demand for plastics production, 2040



Material efficiency could reduce oil demand for plastics production by around 10% in 2040

As an illustrative example, if recycling rates for plastics were to increase to 33% by 2040 (compared with 15% in the New Policies Scenario[8]) and if end-use material consumption were to be reduced by 5% through light-weighting (without substitution effects), about 1.5 mb/d of oil demand for plastics production could be avoided worldwide. Asia Pacific would account for almost half of this saving, and China alone for a quarter (Figure 4.8).

There is huge scope for technological improvements in material efficiency, in particular through the development of lightweight, long-lasting and high-performance materials. These would reduce energy consumption in other sectors, as well as contributing directly to the low-carbon transition: for example, in wind turbines, lightweight materials would make it possible to make use of longer blades, thereby enabling further improvements in generation efficiency and costs.

Much more could also be done to improve the efficiency of the recycling process. Today only around 14% of plastics are collected for recycling, with the remainder either incinerated or discarded.[9] Even when plastics are collected for recycling, losses during sorting and reprocessing processes reduce the savings in oil consumption (WEF, 2016).

Given the potential benefits, there is a strong case for policy-makers to consider the scope for incentivising technology innovation, regulating the inefficient use of materials, and creating an environment more conducive to recycling and reusing materials.[10] So far, material efficiency has drawn attention from policy-makers in advanced economies in Asia Pacific and Europe, but less so in other developing economies. It warrants more widespread attention.

Trends by oil product

The outlook for oil demand in different sectors shapes the prospects of various oil products:

- Kerosene demand registers the largest growth (3 mb/d) over the projection period, aided by strong demand growth in the aviation sector.
- Feedstocks for petrochemical production are close behind: although no single product equals the 3 mb/d increase in kerosene, the combined demand growth of naphtha, LPG and ethane amounts to more than 6 mb/d. LPG demand grows strongly across all sectors in developing economies in Asia and Africa, although this is offset in part by reductions in advanced economies.
- The use of diesel in passenger vehicles has been revised downward in comparison to the *WEO-2016,* reflecting the trend away from diesel vehicles, especially in urban

8. This rate refers to post-consumer collection of waste plastics and does not include processing yields.

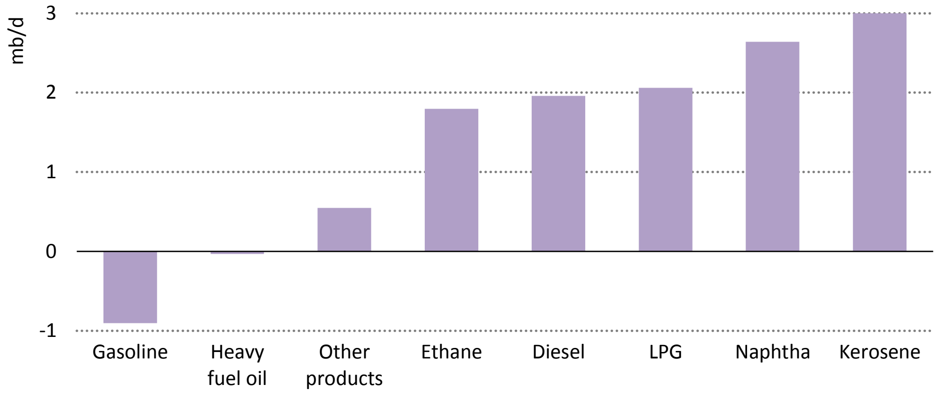
9. It is estimated that around 4 900 million tonnes of plastic waste accumulated in landfills or the natural environment between 1950 and 2015 (Geyer, Jambeck and Law, 2017).

10. See also Chapter 4 of *Energy Technology Perspectives 2017* (IEA, 2017b).

environments. However, robust demand growth for shipping, buses and freight trucks more than compensates for this decline in passenger vehicle use, resulting in a 2 mb/d increase in the use of diesel between 2016 and 2040.

- The story is different for gasoline: rapid improvements in vehicle fuel efficiency and the growing numbers of vehicles fuelled by natural gas, biofuels and electricity reduce gasoline demand by 0.9 mb/d, despite a doubling of the passenger car fleet.
- Heavy fuel oil demand in international maritime transportation rises in absolute terms despite its share in the fuel mix declining. This increase however is more than offset by declines in power generation and industry, meaning a slight reduction in fuel oil demand over the *Outlook* period (Figure 4.9).

Figure 4.9 ▻ Change in global oil product demand in the New Policies Scenario, 2016-2040



Kerosene and petrochemical feedstocks register the largest demand growth; diesel demand increases, while demand for gasoline declines

4.3.2 Supply

Resources and reserves

Our aggregate estimates of the remaining technically recoverable resources of most sources of oil have not changed significantly from the *WEO-2016* (Table 4.4). The main exception relates to tight oil resources in the United States. In the *WEO-2016*, it was assumed that remaining recoverable resource of tight oil totalled 80 billion barrels based upon data from the Energy Information Administration (EIA). The EIA has since revised this to just under 105 billion barrels (US DOE/EIA, 2017). This figure has been regularly revised upwards in previous *World Energy Outlooks* and uncertainty remains high: summing together the highest and lowest resource estimates for individual plays within the United States suggests that resources could range from less than 50 billion barrels to well over 190 billion barrels. However, volumes could be larger than even 190 billion barrels: there are still a number of uncertainties, and understanding of the resource potential in some of the most prolific plays, for example in the Permian Basin, continues to evolve.

Table 4.4 ▷ Remaining technically recoverable oil resources by type and region, end-2016 (billion barrels)

	Conventional crude oil	Tight oil	NGLs	EHOB	Kerogen oil	Total	
						Resources	Proven reserves
North America	248	117	139	805	1 000	2 309	228
Central & South America	240	60	51	496	3	850	321
Europe	62	19	29	3	6	119	14
Africa	313	54	86	2	-	456	129
Middle East	930	29	152	14	30	1 155	813
Eurasia	251	85	60	552	18	966	140
Asia Pacific	133	72	68	3	16	292	50
World	**2 178**	**436**	**585**	**1 875**	**1 073**	**6 146**	**1 695**

Note: EHOB = extra-heavy oil and bitumen.

Sources: IEA database; USGS (2012a, 2012b); OGJ (2016); BP (2017); BGR (2016); US DOE/EIA/ARI (2013, 2014); US DOE/EIA (2017).

Our resource estimate of 105 billion barrels of tight oil includes both crude oil and lease condensate volumes from tight formations. Tight oil production data rarely distinguishes between crude oil and condensate volumes despite the fact that condensate is classified as NGLs for most other sources of production.[11] In this year's *Outlook,* we provide this split for the first time. In the United States, we estimate there to be 97 billion barrels of tight oil resources and 8 billion barrels of lease condensate (that are included as NGLs). The NGL volumes also include NGLs from other tight formations, notably from the massive Marcellus and Utica shale gas plays, as well as NGLs and condensate from conventional formations.

The overall level of proven oil reserves, as published by the *Oil and Gas Journal* or the *BP Statistical Review* (and mostly taken from government sources when available), has dropped by around 8 billion barrels from last year. The largest decreases were seen in the United States, Brazil and Mexico, with Iraq the only country to register any discernible increase (of around 10 billion barrels). Nearly 34 billion barrels were produced globally in 2016, which suggests that the development of new reserves offset nearly three-quarters of the production that took place. Normally a drop in the oil price would be expected to result in downward revisions to proven reserves as volumes become uneconomical at the lower oil price and so move from the "proven" to the "contingent" category. However, remaining proven global reserves have instead increased since the end of 2013 by just over 4 billion

11. Statistics of condensate output used in IEA (2017c) usually include condensate with NGLs for OPEC countries and with crude oil in non-OPEC countries.

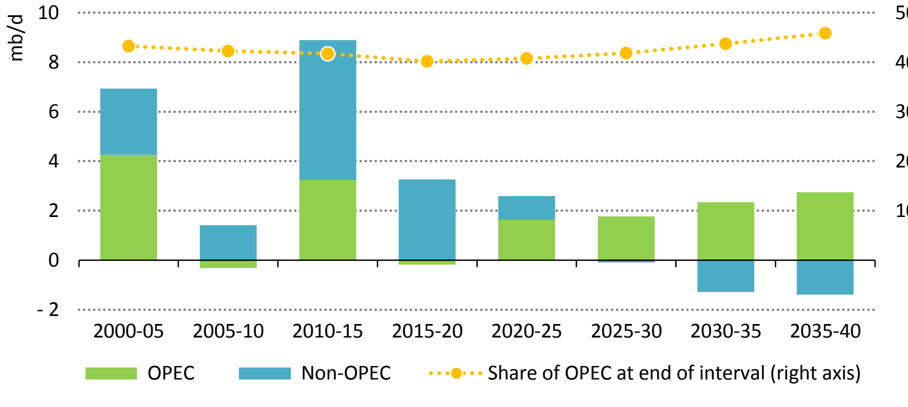
barrels, despite cumulative production of 100 billion barrels in the interim. This could be because some stakeholders have not revised proven numbers, as was perhaps warranted, or because some have reported contingent reserves instead of proven reserves. Whatever the reason, the supply modelling in the World Energy Model relies on estimates of the remaining technically recoverable resource, rather than these (often more widely quoted) numbers for proven reserves.

Production prospects

As with demand, the production outlook to 2040 exhibits two distinct phases (Figure 4.10):

- In the first phase to the mid-2020s, non-OPEC countries dominate global growth. Tight oil from the United States continues its upward march (the United States accounts for 80% of the net increase in production to 2025) and investments made prior to the oil price drop lead to substantial growth from the oil sands in Canada and deepwater developments in Brazil. Output of NGLs also rises, notably from shale gas formations in the United States (Table 4.5). Taken together these increases propel non-OPEC output towards a high point of just over 58 mb/d in the early 2020s. This rise creates a quandary for OPEC countries: should they try to flood the market and push the price lower in the hope that a lower price would choke off such a rapid growth in non-OPEC production, or should they moderate production to support prices, knowing that tight oil producers are likely to step into the breach? In the New Policies Scenario, we assume that OPEC follows the latter course, curbing any substantial growth in OPEC production over this period (unlike in the Low Oil Price Case discussed above where OPEC is more inclined to pursue the former option).

Figure 4.10 ▷ Change in non-OPEC and OPEC oil production in the New Policies Scenario



The production outlook to 2040 goes through two distinct phases: non-OPEC sources dominate near-term increases, but OPEC is increasingly relied upon in the longer term

- In a second phase, from the mid-2020s, tight oil production in the United States begins to fall and the cuts in upstream investment to date increasingly impact production levels (it can take up to five years between final investment decision and first production from a new conventional field development and a further three-to-five years to ramp up to full output). Although oil prices reach levels that allow upstream investment to pick up again, the collective output of non-OPEC countries levels off and then starts to decline, and it is the OPEC countries that increase production in the face of continued (albeit slower) growth in global oil demand.

A focus on production growth can present a misleading picture of the scale of the challenges facing the industry. Compensating for declines in production from existing fields is the main impetus for investment in practice, and competition is fierce between different types of production for the capital that is available for developing new projects. This has led to a renewed focus on the cost and profitability of developments, which has been in a constant state of flux following the drop in oil prices.

Table 4.5 ▷ World oil supply by type in the New Policies Scenario (mb/d)

	2000	2016	2025	2030	2035	2040	2016-2040	
							Change	CAAGR
Conventional crude oil	64.8	67.6	64.6	64.3	63.6	64.1	- 3.4	-0.2%
Existing fields	63.4	66.3	45.9	36.9	29.5	23.5	- 42.7	-4.2%
Yet-to-be-developed	-	-	15.5	17.5	19.2	21.8	21.8	n.a.
Yet-to-be-found	-	-	2.0	6.8	11.0	14.5	14.5	n.a.
Enhanced oil recovery	1.4	1.3	1.3	3.1	3.8	4.3	3.0	5.2%
Tight oil	-	4.5	9.0	9.3	9.6	9.2	4.7	3.0%
Natural gas liquids	9.0	16.2	18.5	19.8	20.6	20.8	4.5	1.0%
Extra-heavy oil and bitumen	0.8	3.3	4.4	4.6	5.0	5.7	2.4	2.3%
Other	0.5	0.7	1.3	1.5	1.7	2.0	1.3	4.5%
Production	**75.2**	**92.4**	**97.8**	**99.4**	**100.5**	**101.9**	**9.5**	**0.4%**
Processing gains	1.8	2.3	2.5	2.7	2.9	3.1	0.8	1.3%
Supply	**77.0**	**94.6**	**100.3**	**102.2**	**103.4**	**104.9**	**10.3**	**0.4%**

Notes: Tight oil includes tight crude oil and condensate production except for the United States, which includes tight crude oil only (US tight condensate volumes are included in natural gas liquids). "Other" includes coal-to-liquids, gas-to-liquids, additives and kerogen oil.

Focus on upstream production costs

Investment into new upstream projects has plummeted by nearly 50% since 2014. The demand for oilfield services and equipment fell in tandem and the cost of drilling and developing new fields has dropped across the board. But faced with a new environment where prices might stay lower for longer (particularly in light of the resilience and rebound demonstrated by tight oil production), as well as severe constraints on their capital budgets, companies have been seeking a variety of other methods to secure additional cost reductions. There are many examples of them successfully doing so. The announced cost of developing the ultra-deep water project Mad Dog II in the Gulf of Mexico fell by around 50% between the initial design in 2013 and the time of final approval at the beginning of 2017. Similarly, the capital costs for the Johan Castberg field in the Barents Sea are estimated to have fallen by over 60% since the original development concept was initially announced in 2013. A critical question for the industry now is whether these cost reductions can be maintained permanently, i.e. whether they represent a structural change in the cost of developing new projects, or whether they are a temporary and cyclical phenomenon that will be reversed when industry activity picks up again. We explore this question by unpacking the key reasons why capital costs for conventional production have fallen to date, and then by examining how these elements might evolve in the future.

Three key factors led to the reduction in aggregate capital costs seen in recent years: changes in the types of projects that are executed; changes in the design of projects; and changes in the cost of implementing a given project design.[12] The first two elements reflect the increasing focus by companies on projects that deliver high rates of return rather than high reserve volumes: in other words a shift from volume to value (Box 4.3). Since the fall in prices in 2014, upstream companies have placed greater emphasis on developing only their highest-value prospects, taking account of the lower level of capital available and the need to ensure competitiveness in a low-price environment. There has been a parallel shift towards projects with shorter investment cycles: the clearest example of this is investment towards tight oil, but it has been visible also in a preference for conventional crude oil projects with shorter lags between approval and first production and shorter payback periods (IEA, 2017d). This "high grading" of assets leads to an overall reduction in the average capital cost of the projects that go ahead.

This emphasis on executing high-value prospects has also led to a revaluation of the design of new projects. A number of proposed projects have been "downsized" by reducing the total volume of oil that will be recovered or by lowering the planned level of peak production. Part of the cost reduction in Mad Dog II, for example, was achieved through a 10-20% reduction in the level of resources that will be produced from the field. A related knock-on effect has been the simplification of project designs. With smaller planned production capacities, it has been possible in some instances to change the type of infrastructure installed (including the choice of offshore platform) or to remove or reduce infrastructure (including infrastructure originally put in place to support future developments). Some operators have also benefited from experience gained in executing tight oil projects and have been applying a more standardised approach towards the management and execution of conventional projects.

12. A further element leading to reductions in the headline costs of projects for some companies has been a reduction in the value of local currency when expressed in US dollars. We take this into account in this *Outlook w*hen examining energy prices, investments and costs, but since we do not attempt to model exchange rate fluctuations in the future, this is assumed to have a one-off impact and so is not examined further.

Box 4.3 ▷ Choosing value versus volume

We can illustrate the impact of a company choosing to focus on maximising the value of a project rather than the volumes recovered, by examining various design strategies for developing a notional newly discovered field. Suppose a new deepwater field with around 1 500 million barrels of initial oil-in-place was discovered in around 2 300 metres of water.

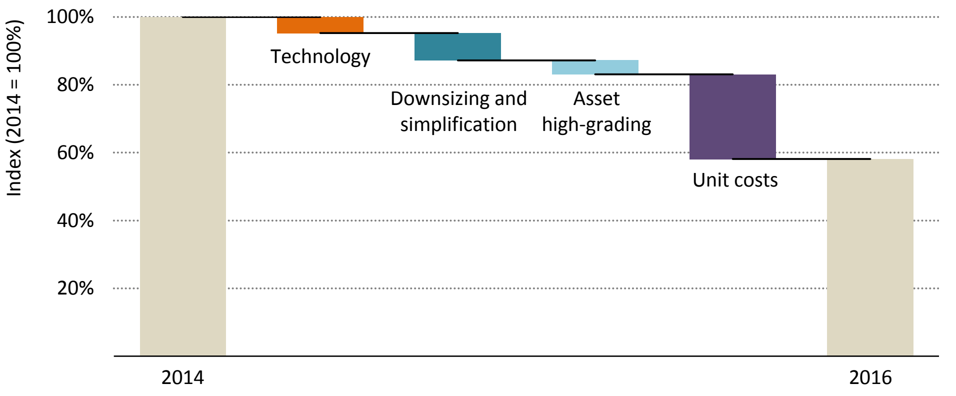
One development strategy would be to drill around 25 wells over a period of ten years. Around 25% of the initial oil-in-place would be recovered and total capital costs would be around $10 billion, taking into account drilling rig hire costs, design and construction of the production platform and raw materials.

An alternative strategy would be to drill fewer wells but focus these on the most productive areas. This would lower the level of peak production and so the platform could likely be downsized. By drilling 11 rather than 25 wells, the recovery factor for the field would drop to around 15% (the recovery from each well would be slightly higher) and total capital costs would fall to around $5.5 billion. In this indicative case, downsizing and simplifying the design of the development means that around 150 million fewer barrels will ultimately be produced from the field, but that the cost per barrel will around 10% lower than would have been the case if the aim had been to maximise recovery.

The IEA Upstream Investment Cost Index (UICI) is an indicator of how the capital costs of a set of representative upstream oil and gas projects around the world (excluding US onshore projects) have evolved over time (IEA, 2017d). It is based on changes in the cost of the construction materials and equipment (e.g. steel, cement), labour, drilling rigs and oilfield services required to develop these projects. The UICI fell by around 30% between 2014 and 2016, as a result of technological improvements and a drop in unit costs.[13] The majority of the decrease in the UICI resulted from a reduction in unit costs rather than from the kind of technological innovation that has drastically reduced the cost of producing tight oil and shale gas in the United States in recent years. Demand for oilfield labour and equipment has contracted sharply since 2014, dragging down the costs of these services and reducing margins for service companies, and the costs of many critical raw materials have also fallen. In total, we estimate that reductions in unit costs, advances in technology, downsizing and simplification, and asset high grading, have led to a 40% decrease in the average cost of developing a new conventional field since 2014 (Figure 4.11).

13. Unit costs are the cost of doing a certain amount of work such as the cost of hiring a drilling rig for a day or the cost per metre drilled for a new well.

Figure 4.11 ▷ Reductions in the capital cost per barrel for developing conventional oil projects



Capital costs for conventional projects have fallen by just over 40% since 2014, with unit costs accounting for nearly 60% of the overall reduction

The future evolution of costs

The drop in the oil price compelled operators to reduce costs to maintain competitiveness. Reductions in unit costs, downsizing and simplification have been successful to the point that a number of new projects have received development approval. Yet to what extent can these cost reductions be maintained?

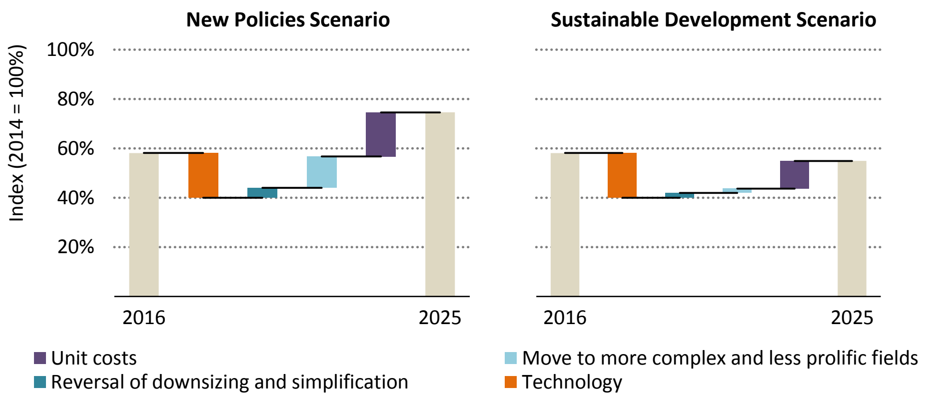
It is clear that the adoption of new technologies means a structural reduction in costs. Increased digitalisation, the use of "big data" (for example to enhance geological understanding of a reservoir) and progress in robotics present the upstream industry, like any other industry, with new opportunities for reducing costs, improving efficiencies and increasing recovery (IEA, 2017e). In contrast, reductions in unit costs are a purely cyclical phenomenon. As the oil price rises, companies restart upstream activity and new investments pick up, eventually leading to an increase in unit costs. There remains a large overhang in the availability of oilfield equipment (especially in the offshore industry), which could slow the reaction in unit costs, but once this overhang is eliminated we anticipate that unit costs globally revert to the traditional pattern of moving broadly in line with prices.

The durability of the cost reductions from downsizing and simplification are more difficult to assess. It is possible that they could represent structural changes in the types of projects developed and the design strategy used, but this is likely only to be the case if there has been a lasting change in corporate behaviour. In previous price downturns the industry similarly emphasised the importance of optimising projects for value rather than volumes recovered, though this dissipated when prices rose. It remains to be seen whether it will be any different this time. In addition, near-term cost reductions secured by taking out infrastructure from project plans (that would have been used to support future developments) could also lead to an overall increase in costs in the long term, if oil demand continues to rise and these future developments are needed.

The evolution and magnitude of changes in unit costs, downsizing and simplification therefore depend on the price trajectory and the consequent industry response:

- In the New Policies Scenario, oil demand and prices rise to 2025 and some of the cost reductions seen to date are overturned. There is a partial reversion in the industry away from a rigid focus on high-value projects, reversing the reductions seen to date from downsizing and simplification. But there is also some lasting change in corporate behaviour that leads to more efficient and standardised processes and project designs, as well as continued technological innovation. However, unit costs increase as prices rise, and the remaining conventional projects that need to be developed become more complex and less productive. The net result is a 30% increase in overall capital costs between 2016 and 2025 (Figure 4.12). Despite this sizeable increase, global average capital costs in 2025 in the New Policies Scenario remain 25% below 2014 levels.
- In the Sustainable Development Scenario, oil demand peaks around 2020 and prices remain at much lower levels. The increase in unit costs is therefore less severe: there is less need to develop more complex projects, and the industry maintains a greater focus on developing high-value projects. As a result, by 2025 the costs of conventional projects in the Sustainable Development Scenario stay around 40% below 2014 costs.[14]

Figure 4.12 ▷ Evolution of average capital cost per barrel for conventional oil projects by scenario



Average costs in the New Policies Scenario recover as prices rise and companies develop more complex fields but costs remain suppressed in the Sustainable Development Scenario

14. The assumption that the industry will react differently in the New Policies Scenario compared with the Sustainable Development Scenario as a result of the divergence in demand is a key difference in this *Outlook* than in previous editions of the *World Energy Outlook* (see Chapter 1).

In summary, the cost-cutting measures implemented by operators to date have been vital to maintaining competitiveness. Downsizing and simplifying project designs played an important part, but the largest reductions came from falls in the cost of procuring construction materials and equipment, and of contracting drilling rigs and oilfield services. Maintaining these reductions will be difficult unless demand peaks and there is continued slack in markets for services and supplies. Continued technological innovation will also be critically important because the recent emphasis on executing high-value projects is by no means guaranteed to last if prices rise.

Oil production by type

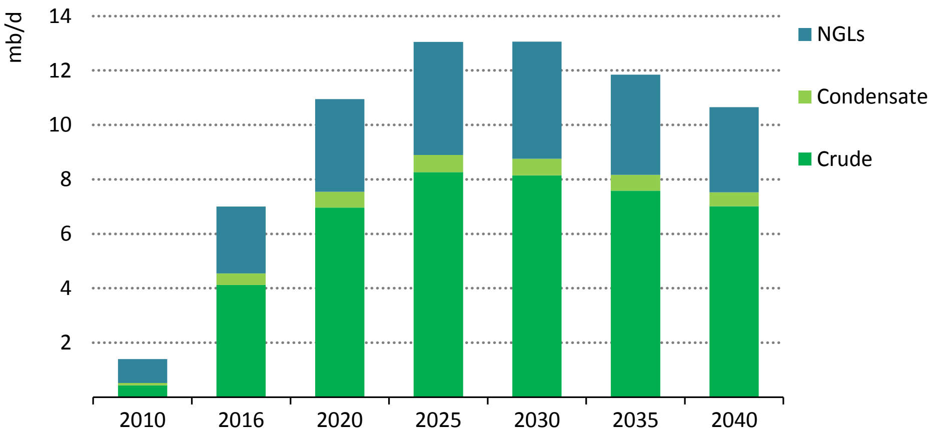
With the exception of tight oil in the United States (discussed in more detail below) there are few changes from the *WEO-2016* in this *Outlook* to 2040 for the various types of oil production. The New Policies Scenario sees:

- Global conventional crude oil production declining slowly to 2040, with new fields that have yet-to-be-developed or yet-to-be-found not able to offset entirely the underlying declines from existing fields. An increasingly important component of these new developments comes from fields found in deep and ultra-deep waters: between 2016 and 2040 these fields add over 3.5 mb/d to global oil supplies (Spotlight).
- Total production of extra-heavy oil and bitumen rising by 2.4 mb/d to just over 5.5 mb/d by 2040, despite a number of changes in the companies operating and developing Canada's oil sands and continuing concerns about the investment climate in Venezuela.
- Tight oil production outside the United States growing to 2.2 mb/d by 2040.

The biggest change in this *Outlook* compared with the *WEO-2016* is tight oil production in the United States. When oil prices fell at the end of 2014 it was envisaged that total production would soon follow suit. Monthly tight oil production did indeed fall by over 500 thousand barrels per day (kb/d) from its peak at the beginning of 2015 to its lowest point in 2016. But this drop was much less dramatic than many had anticipated, largely as a result of operators shifting drilling to their most productive acreage and drastically reducing costs (see section 3.3.2 in the *WEO-2016*). Since then operators have continued to optimise the efficiency of their hydraulic fracturing operations while also increasing their understanding of the geological characteristics of plays. After prices rose from the beginning of 2016, the shale gas and tight oil industry reacted rapidly, with the US onshore rig count increasing at its fastest ever rate on record in the 12 months after its nadir in May 2016. Production has since risen apace, reaching a new record level in mid-2017, and the current expectation is that it will continue to flourish.

Attention over the longer term has thus turned to how high tight oil production can rise and for how long it can remain at elevated levels. For this, the estimated level of tight oil resources remains the critical assumption, but also the cause of most uncertainty (see section 4.3.2). In the New Policies Scenario, production of all liquids (i.e. crude, lease condensate and NGLs) from tight formations (including sandstone, chalk and shale plays) grows to 13 mb/d in 2025 (Figure 4.13). This is led by growth in tight crude oil, which doubles from current levels to 8.3 mb/d in 2025. This is a more rapid rise in production than in the *WEO-2016* (which reached around 6 mb/d in 2025),[15] reflecting the increase in the estimated amount of resource available and a faster assumed deployment of drilling rigs as prices rise. Tight NGLs, including lease condensate, grow by nearly 2 mb/d to 2025, led by increases in ethane recovery (see section 4.3.1).

Figure 4.13 ▷ US tight liquids production in the New Policies Scenario



Tight liquids production in the United States grows to 13 mb/d by the mid-2020s before falling back to just over 10.5 mb/d in 2040

Production plateaus after 2025, and tight liquids decline after 2030 by around 2%/year to just over 10.5 mb/d in 2040. This decline is due in large part to a fall in NGLs production: while shale gas production is broadly constant throughout the 2030s in the New Policies Scenario (see Chapter 8), there is a shift from "wet" plays (such as the Eagle Ford) that produce significant levels of liquids towards "dry" plays (such as Haynesville and Fayetteville) that produce much lower levels of NGLs. Tight crude oil production remains more robust, but still declines by around 1.1 mb/d from its peak to 7 mb/d in 2040.

There is technological innovation in tight oil production throughout the New Policies Scenario, with operators improving recovery rates and reducing the amount of time to drill and complete wells (although future improvements are likely to be relatively small). As production continues to rise, however, higher levels of investment and larger numbers of drilling rigs and wells are required simply to sustain production. While the vast number of wells that have been drilled by 2025 provides an important base level of production, drilling and completing new wells remains vital.[16] From the mid-2020s, operators are forced

15. The *WEO-2016* figure includes production of both tight crude oil and tight condensate.

16. Production from a tight oil well initially declines rapidly but this eventually slows; while volumes coming from an individual well may be small, the aggregated volumes from a large number can be significant.

to move outside the play "sweet spots" as these become increasingly depleted, meaning that each well yields less production. Allied with a slowdown in the rate at which the oil price increases, this leads to a plateau and then a decline in tight crude oil production.

SPOTLIGHT

Can deepwater developments adapt to the new investment climate?

Deepwater and ultra-deepwater projects require high upfront capital investment and can have long payback periods, especially compared to tight oil.[17] As prices fell from the end of 2014, deepwater prospects were therefore some of the first to be delayed or cancelled. According to Rystad Energy, the average annual level of resources in new deepwater and ultra-deepwater projects receiving approval between 2014 and 2016 fell to less than 1.5 billion barrels, 60% lower than the level since 2000, compared with a 35% drop in other conventional projects.

Four countries currently account for nearly 90% of deepwater and ultra-deepwater production globally: Angola, Brazil, Nigeria and the United States. Yet the reduction in investment activity has not been spread evenly. Activity in Angola and Nigeria suffered to a disproportionate degree with companies reluctant to invest in the light of local content requirements, increased instability in Nigeria, and less cost deflation than has been experienced elsewhere. In contrast, activity in the United States portion of the Gulf of Mexico has continued apace, with two major recent projects Appomattox (approved in 2015) and Mad Dog Phase II (approved in 2017) set to add over 300 kb/d of new production in aggregate at peak. In Brazil, Petrobras has spent aggressively in recent years to develop projects in the resource-rich pre-salt basins (albeit less aggressively than they had originally planned). Despite multiple cost over-runs and a severe financial scandal, this investment is now beginning to bear fruit. Brazilian production reached an all-time high of 2.2 mb/d in 2016 and is expected to grow by around 1 mb/d over the next five years. The removal of Petrobras's mandatory minimum 30% operating stake in new developments has also spurred further interest from a number of foreign investors.

A number of new and emerging deepwater areas have also been receiving increased attention recently, most notably in Mexico, Guyana and Suriname. Since embarking on the liberalisation of its oil sector in 2013, successful bidding rounds have raised expectations for future growth from Mexico's offshore: as discussed in the *WEO-2016*,[18] deepwater production – with sufficient investment – could add up to 1 mb/d by 2040, reversing the long-term decline in Mexican output. In Guyana, ExxonMobil announced in mid-2017 the first phase of development of the Liza field, with planned

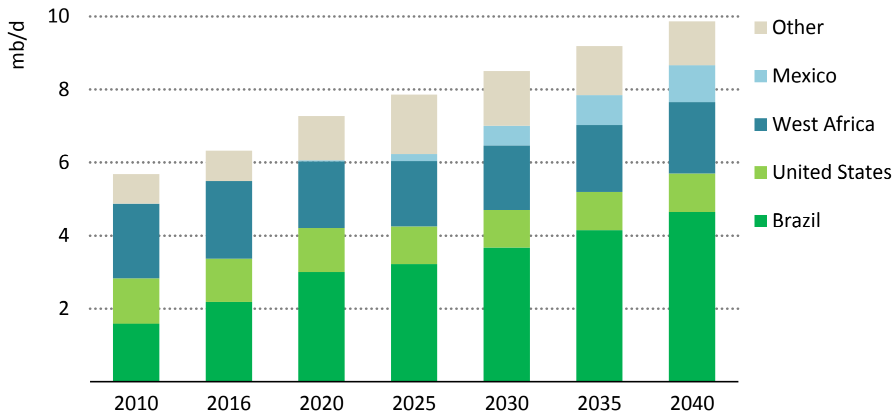
17. Deepwater fields have water depths between 400-2 000 metres and ultra-deepwater fields greater than 2 000 metres.

18. See *Mexico Energy Outlook: World Energy Outlook Special Report*, 2016, available at: *www.iea.org/weo/mexico*.

peak production of around 100 kb/d expected to occur in the early 2020s. This has led to a high degree of interest in exploring neighbouring areas, including in Suriname.

In the New Policies Scenario, crude oil production from deepwater and ultra-deepwater fields grows from 6.3 mb/d in 2016 to 7.9 mb/d in 2025, and to 10 mb/d in 2040 (Figure 4.14). The share of ultra-deepwater more than doubles during this period (from 12% in 2016 to nearly 25% in 2040), largely as a result of increases in Brazil. But there are also some potential clouds on the horizon for deepwater developments. Many recent investment decisions benefited from the ability to connect to existing infrastructure, thus avoiding the need to install new subsea pipelines, production platforms and processing units (known as "tie-backs"). This process of developing a region in increments has been critical to the success of offshore production in the Gulf of Mexico, and it will be important for the industry to demonstrate that it is cost effective to open up entirely new offshore regions in the current investment climate. Similarly, it will be vital for competitiveness that reductions in cost do not simply rebound when prices rise.

Figure 4.14 ▷ Deepwater and ultra-deepwater production by region in the New Policies Scenario



Deepwater and ultra-deepwater oil production increases by over 50% over the next 25 years with Brazil providing nearly half of production in 2040

Non-OPEC production

Total non-OPEC production reaches a high point in the mid-2020s, led by increases in the United States, Brazil and Canada (Box 4.4), before falling back. Russian production has been revised upwards in the medium term, compared with the *WEO-2016*, given the resilience shown by operators (aided by the decline in the value of the rouble and the structure of Russia's taxation system), despite the drop in oil prices and sanctions restricting access to finance and technology. Over the longer term, however, production in Russia is projected to decline gradually as the eventual move to new frontier projects in east Siberia and the Arctic, together with some tight oil development, is insufficient to offset declines in the mature production areas in western Siberia and the Volga-Urals region. Russia production falls to 8.6 mb/d in 2040 (Table 4.6).

Table 4.6 ▷ Non-OPEC oil production in the New Policies Scenario (mb/d)

							2016-2040	
	2000	2016	2025	2030	2035	2040	Change	CAAGR
North America	14.2	19.4	24.9	25.4	25.0	24.5	5.1	1.0%
Canada	2.7	4.5	5.4	5.5	5.9	6.2	1.7	1.4%
Mexico	3.5	2.5	2.7	3.0	3.3	3.4	1.0	1.4%
United States	8.0	12.5	16.9	16.8	15.9	14.9	2.4	0.7%
Central & South America	3.2	4.5	5.3	5.8	6.3	6.8	2.3	1.7%
Argentina	0.9	0.6	0.6	0.7	0.8	0.8	0.2	1.2%
Brazil	1.3	2.6	3.6	4.1	4.6	5.2	2.6	2.9%
Europe	7.1	3.7	3.6	3.3	2.9	2.6	-1.2	-1.6%
Norway	3.3	2.0	1.9	1.7	1.5	1.3	-0.7	-1.9%
Africa	1.5	1.7	1.7	1.9	1.7	1.6	-0.1	-0.2%
Middle East	2.2	1.3	1.3	1.3	1.3	1.1	-0.1	-0.5%
Eurasia	7.9	14.1	13.7	13.1	12.5	11.9	-2.2	-0.7%
Kazakhstan	0.7	1.6	2.3	2.4	2.5	2.5	0.9	1.8%
Russia	6.5	11.3	10.5	9.7	9.1	8.6	-2.8	-1.2%
Asia Pacific	7.9	8.1	7.3	7.0	6.8	6.7	-1.4	-0.8%
Australia	0.8	0.4	0.5	0.6	0.7	0.8	0.4	3.3%
China	3.3	4.0	3.5	3.3	3.2	3.1	-0.9	-1.1%
India	0.8	0.8	0.9	0.9	0.9	0.9	0.0	0.1%
Indonesia	1.4	0.9	0.7	0.6	0.5	0.5	-0.4	-2.2%
Non-OPEC	**43.9**	**52.8**	**57.9**	**57.8**	**56.6**	**55.2**	**2.4**	**0.2%**
Non-OPEC share	*58%*	*57%*	*59%*	*58%*	*56%*	*54%*	*-3%*	*n.a.*
Conventional crude oil	36.7	35.7	33.2	32.1	30.3	29.2	-6.5	-0.8%
Tight oil	-	4.5	9.0	9.3	9.5	9.2	4.6	3.0%
United States	-	4.1	8.3	8.1	7.6	7.0	2.9	2.2%
Natural gas liquids	6.2	9.7	11.4	11.8	11.8	11.4	1.7	0.7%
Canada oil sands	0.6	2.4	3.3	3.4	3.5	3.7	1.3	1.8%
Other	0.4	0.5	1.0	1.2	1.4	1.7	1.2	5.4%
Coal-to-liquids	0.1	0.1	0.2	0.4	0.5	0.6	0.5	7.1%
Gas-to-liquids	0.0	0.0	0.0	0.0	0.1	0.3	0.2	8.9%

Notes: Global tight oil figure includes tight crude oil and condensate production except for the United States, which includes tight crude oil only (US tight condensate volumes are included in natural gas liquids). "Other" includes extra-heavy oil and bitumen, coal-to-liquids, gas-to-liquids, additives and kerogen oil.

Box 4.4 ▷ Prospects for Canadian oil sands development in the New Policies Scenario

A number of major oil companies announced their intention to sell or downsize their holdings in Canada's oil sands from the end of 2016. Statoil, Shell, Marathon Oil and ConocoPhillips announced that they would sell around 300 kb/d production in aggregate to a variety of Canadian companies with a more specialist focus on oil sands development. While other major companies continue to maintain a presence in oil sands operations, it remains an open question whether the exit of these companies will impact prospects for oil sands development over the longer term. There is also an unresolved question about how oil is transported to demand centres in the light of a number of delays in the development of transmission and export pipelines.

In the New Policies Scenario, oil sands production in Canada grows from 2.4 mb/d in 2016 to 3.7 mb/d in 2040. Most of this growth takes place over the next five years as projects that were approved prior to the drop in oil prices start to come online; the remaining growth emerges slowly over subsequent years. The vast majority of projected new projects after 2025 use underground "in situ" extraction (typically via steam injection) rather than mining deposits nearer the surface. In situ projects tend to have lower production costs, a shorter lag between investment and first production, and lower upfront capital requirements than combined mining and upgrading projects. In situ projects have also historically been progressed in relatively small phases, often providing incremental production on the order of 25-35 kb/d, whereas mining projects have been major undertakings, with phases often adding around 100-120 kb/d of new production. In situ projects are therefore better suited to specialist operators who may have more constrained capital budgets.

Two greenhouse-gas (GHG) emissions reduction initiatives launched by the government in Alberta have implications for oil sands. The first is a tax of Canadian dollars (CAD) 20 per tonne of CO_2-equivalent (t CO_2-eq) that will rise to CAD 30/t CO_2-eq in 2018 and increase in real terms thereafter. The second is a 100 Mt CO_2-eq limit placed on annual GHG emissions from upstream oil sands operations (excluding emissions from cogeneration) plus a 10 Mt CO_2-eq allowance for annual emissions from new upgrader facilities. Average GHG emissions are currently around 85 kilogrammes (kg) of CO_2-eq per barrel produced and so the GHG price has had only a minor impact on production costs: the 2018 GHG price would increase production costs by around CAD 2.5/bbl. Annual upstream oil sands GHG emissions are around 70 Mt, and in the absence of a cap on GHG emissions, emissions from upstream oil sands production (excluding emissions from cogeneration and new upgrading facilities) would likely reach around 110 Mt by 2040. As a result of the cap, the industry is likely to seek ways to reduce the GHG intensity of production: in the New Policies Scenario, this is estimated to fall to around 75 kg of CO_2-eq per barrel in 2040, without any significant increase in costs.

Production in China also declines throughout the New Policies Scenario: investment in China's upstream sector has plummeted since the drop in prices and the challenge for operators is now more to slow, rather than reverse, the rate of decline (see Chapter 14). A number of other non-OPEC countries register growth over the course of the New Policies Scenario, including Kazakhstan, Australia and Argentina, the latter two benefiting from modest growth in tight oil production in later years. However, these increases are insufficient to offset the declines elsewhere and non-OPEC production falls by around 3 mb/d from its peak level to 2040.

OPEC production

There have been some changes in OPEC membership since our last *Outlook*: Indonesia again suspended its membership, less than a year after re-joining, as it was unable to agree to take part in the production cuts announced at the end of 2016, while Equatorial Guinea joined in mid-2017. There are no major changes in the long-term production outlook for members of OPEC, however there are a number of revisions in the medium term affecting individual countries. In overall terms, on a like-with-like comparison (i.e. including Equatorial Guinea and excluding Indonesia), OPEC production in 2025 is some 1.1 mb/d lower than in the *WEO-2016.* With the growth in non-OPEC production, OPEC production barely shows any increase to 2025 and only just manages to keep its share of the market above 40% (Table 4.7).

Declines to 2025 are seen in nearly all OPEC member producers outside of the Middle East with the exception of Libya. Libya has recently managed to increase production despite the continuing threat of attacks on its oil infrastructure, but its outlook remains particularly uncertain. Over the longer term we assume some degree of stabilisation and recovery, but production in 2040 remains well below its historic peak in the 1970s of over 3 mb/d. Algeria and Venezuela both see drops of around 0.25 mb/d between 2016 and 2025. Algeria has been pursuing efforts to stem the ongoing decline in production since its peak in 2007. It successfully manages to do so in the New Policies Scenario from 2025 onwards, with production remaining above 1.3 mb/d. In Venezuela, persistent underinvestment, a wider economic crisis and continuing political instability mean it is unlikely to be in a position to increase production materially any time soon.

Production from Middle Eastern members of OPEC fares considerably better. Overall output grows by nearly 6 mb/d to 2040, with Iraq leading the way. Production growth in Iraq in recent years has been remarkably resilient despite severe budgetary constraints and ever-present security threats, although these present clear downside risks to our projection of 7 mb/d by 2040. There are multiple uncertainties too with the outlook for Iran, which hold back the pace of anticipated investment in new projects, even though a number of foreign companies are seeking to expand production and investment levels. In the New Policies Scenario, Iraq becomes OPEC's second-largest producer with production increases underpinned by its huge, low-cost resource base and the fiscal pressures on it to increase production, while Iran's output rises to around 6 mb/d. Nevertheless, Saudi Arabia maintains its primacy among

OPEC countries, with production growing by 1 mb/d between 2016 and 2040, nearly two-thirds of which comes from NGLs. Saudi Arabian crude oil production in 2040 is just under 11 mb/d. The complexity of new developments in Saudi Arabia is anticipated to increase, but production costs will continue to remain among the lowest in the world.

Table 4.7 ▷ OPEC oil production in the New Policies Scenario (mb/d)

							2016-2040	
	2000	2016	2025	2030	2035	2040	Change	CAAGR
Middle East	21.3	30.4	31.4	33.1	34.8	36.5	6.1	0.8%
Iran	3.8	4.4	5.1	5.5	5.7	5.9	1.5	1.3%
Iraq	2.6	4.5	5.0	5.6	6.2	7.0	2.5	1.9%
Kuwait	2.2	3.2	3.1	3.1	3.2	3.3	0.1	0.2%
Qatar	0.9	2.0	2.0	2.2	2.4	2.5	0.5	1.0%
Saudi Arabia	9.3	12.4	12.3	12.7	13.0	13.4	1.0	0.3%
United Arab Emirates	2.6	3.9	3.9	4.0	4.2	4.3	0.5	0.5%
Non-Middle East	9.9	9.2	8.4	8.5	9.1	10.1	1.0	0.4%
Algeria	1.4	1.6	1.4	1.3	1.3	1.3	-0.3	-0.7%
Angola	0.7	1.8	1.5	1.5	1.5	1.5	-0.3	-0.7%
Ecuador	0.4	0.5	0.4	0.4	0.3	0.3	-0.2	-2.4%
Equatorial Guinea	0.1	0.2	0.1	0.1	0.1	0.1	-0.2	-5.2%
Gabon	0.3	0.2	0.2	0.1	0.1	0.1	-0.1	-3.9%
Libya	1.5	0.4	1.0	1.1	1.2	1.5	1.0	5.3%
Nigeria	2.2	1.9	1.7	1.9	2.1	2.5	0.6	1.1%
Venezuela	3.2	2.4	2.1	2.2	2.4	2.9	0.5	0.7%
Total OPEC	**31.2**	**39.6**	**39.8**	**41.6**	**43.9**	**46.7**	**7.1**	**0.7%**
OPEC share	*42%*	*43%*	*41%*	*42%*	*44%*	*46%*	*3%*	*n.a.*
Conventional crude oil	28.1	31.9	31.4	32.1	33.3	34.9	3.0	0.4%
Natural gas liquids	2.8	6.6	7.1	8.0	8.8	9.4	2.8	1.5%
Venezuela extra-heavy	0.2	0.9	1.1	1.2	1.5	2.0	1.1	3.4%
Other	0.1	0.2	0.3	0.3	0.4	0.4	0.2	2.2%
Gas-to-liquids	-	0.2	0.2	0.2	0.2	0.2	0.1	1.7%

Notes: Data for Saudi Arabia and Kuwait include 50% each of production from the Neutral Zone. "Other" includes tight oil, extra-heavy oil and bitumen, coal-to-liquids, gas-to-liquids, additives and kerogen oil.

4.3.3 Refining

After a year of buoyant margins in 2015, a large inventory overhang in 2016 put downward pressure on refining margins: this limited annual throughput growth to around 600 kb/d, less than half of the growth in oil demand (1.3 mb/d) over the same period. Despite this, the refining industry continues to enjoy a prosperous period relative to the early 2010s when a higher level of overcapacity weighed heavily on margins. Margins have remained broadly favourable so far throughout 2017 due to the combined effect of robust demand, delays in new capacity additions, and some closures of refinery capacity in recent years.

Nonetheless, the risks that have historically pressured refiners remain present. Alternative routes to meet liquid demand, such as biofuels and products fractionated from NGLs, continue to eat into the share of refineries through to 2040 (Table 4.8). Moreover, some 18 mb/d of new refining capacity is projected to come online over the projection period despite the high levels of spare capacity and a slowdown in the pace of demand growth.

Table 4.8 ▷ World liquids demand in the New Policies Scenario (mb/d)

	2016	2025	2030	2035	2040
Total liquids	**95.5**	**102.8**	**105.3**	**107.0**	**109.1**
Biofuels	1.7	2.5	3.1	3.6	4.1
Total oil	93.9	100.3	102.2	103.4	104.9
CTL, GTL and additives	0.7	1.2	1.4	1.7	1.9
Direct use of crude oil	1.2	0.7	0.5	0.3	0.3
Oil products	92.0	98.4	100.3	101.4	102.8
Fractionation products from NGLs	9.2	10.9	11.4	11.5	11.1
Refinery products	82.8	87.5	88.9	89.9	91.6
Refinery market share	*87%*	*85%*	*84%*	*84%*	*84%*

Note: CTL = coal-to-liquids; GTL = gas-to-liquids.

These new refining capacity additions are concentrated in Asia and the Middle East, which collectively account for nearly 80% of the new additions globally to 2040, and fundamentally reshape the competitive landscape of the refining industry. Newly built refineries are in general more efficient and better configured to serve changing demand patterns. Supported by robust domestic demand, their utilisation is likely to remain high, putting counterparts (especially in Europe) at risk of lower utilisation or closure. Today, the Middle East and developing economies in Asia account for 36% of global refinery throughput: this share increases to 47% in 2040 in the New Policies Scenario. Over 60% of new capacity comes online between today and 2025, which has a marked effect on patterns of oil trade. Over the past decade, trade in oil products has grown faster than crude oil trade as a result of the growth of export-oriented refiners, and it continues to do so through to 2025: after that date, both crude oil and oil products trade expand at a similar pace as new refineries are built close to demand centres.

Global refinery runs in the New Policies Scenario rise by 8.7 mb/d between 2016 and 2040 (Table 4.9). Growth is strongest in developing economies in Asia and the Middle East, and this more than offsets the declines seen elsewhere. The Middle East, which exhibits the largest growth of 4.2 mb/d, becomes the leading product exporter in the world by 2020. China, India and Southeast Asia collectively increase throughput by almost 9 mb/d, mostly to meet growing domestic demand, while Japan and Korea register a reduction in throughput to 2040, as do many other mature economies where oil demand is declining.

One key exception is the United States, which, despite also facing a decline in oil demand over the long term, benefits from the high level of complexity of its refineries (meaning they have greater capability to produce the products most in demand), growing demand in adjacent regions (notably Latin America) and the ample availability of domestic oil. Nevertheless, there are limits to the level of light crude oil that refineries in the United States can process (see section 4.3.4). As demand for gasoline in the United States wanes, US refineries emerge as major gasoline exporters to regions such as Latin America, Africa and (to a lesser extent) Asia. Over the long term, as the gasoline surplus intensifies, higher cost refiners, notably those along the east coast, may face challenges in sustaining their utilisation rates.

Table 4.9 ▷ Refining capacity and runs by region in the New Policies Scenario (mb/d)

	Capacity	Net capacity change to	Refinery runs			Capacity at risk	
	2016	2040	2016	2025	2040	2025	2040
North America	21.7	-0.4	18.8	18.5	16.8	0.5	2.7
Europe	16.2	-0.9	13.3	11.8	10.0	2.7	4.8
Asia Pacific	34.1	8.0	27.9	30.7	35.0	4.7	3.8
Japan and Korea	6.8	-0.7	6.2	5.5	4.6	0.5	1.4
China	15.6	2.6	10.8	12.5	14.0	3.8	2.3
India	4.7	3.0	4.9	5.5	7.7	-	-
Southeast Asia	4.8	2.9	4.2	5.4	6.8	0.1	-
Russia	6.4	0.0	5.6	5.0	4.8	0.7	0.9
Middle East	9.0	4.1	7.2	10.0	11.4	0.5	0.3
Africa	3.3	1.8	2.1	3.3	4.5	0.4	0.1
Brazil	2.2	0.8	1.9	2.1	2.6	-	-
Other	4.9	0.3	3.2	3.5	3.4	1.2	1.3
World	**97.7**	**13.7**	**79.8**	**85.0**	**88.5**	**10.6**	**14.0**
Atlantic Basin	54.2	1.6	44.3	43.8	41.6	5.5	9.8
East of Suez	43.5	12.1	35.5	41.2	46.9	5.2	4.2

Notes: "Capacity at risk" is defined as the difference between refinery capacity and refinery runs, with the latter including a 14% allowance for downtime. This is always smaller than spare capacity, which is the difference between capacity and refinery runs. Projected shutdowns beyond those publicly announced are also counted as "capacity at risk".

There is a growing trend of introducing and tightening regulations to reduce SO_2 emissions, particularly for transportation fuels, which has significant implications for refiners. For example, the Euro V standards, which require a reduction in the sulfur content of gasoline and diesel to less than 10 parts per million (ppm), have been widely adopted in various countries; many of the largest oil-consuming countries, including China and India, are also now in the process of introducing similar standards. In similar vein, the International Maritime Organization has decided to limit SO_2 emissions from marine transportation from

2020 onwards, which poses a near-unprecedented challenge to the refining industry (see section 4.3.1). "Desulfurisation" is fast becoming an irreversible global trend. The IMO decision and other low-sulfur regulations are likely to support the margins of complex refineries, which are able to produce low-sulfur products, and undermine those of simpler or older refineries, many of which are already suffering from low profitability. Refiners will need to invest in upgrades, retrofits or hydro-treating facilities to meet these ever-tightening standards.

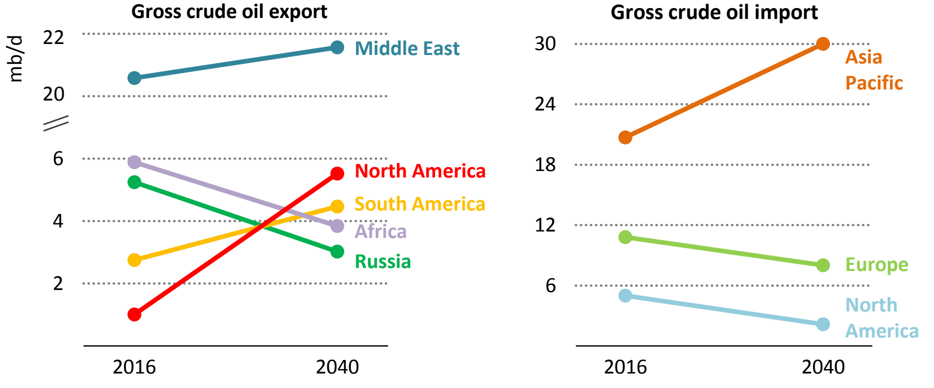
4.3.4 Trade and oil security

Crude trade trends[19]

Global crude oil trade expands by 4 mb/d over the period to 2040 in the New Policies Scenario. Yet the modest change in the headline figure does not do justice to the dynamism of the underlying shifts in the importer-exporter landscape and the direction of trade flows. Over the *Outlook* period, three major trends reshape the global crude trade picture (each of which is examined in more detail below):

- The rise of the United States as a major crude exporter, which helps North America become the second-largest provider of crude oil to the global market by 2040, ahead of South America and Russia, and behind only the Middle East (Figure 4.15).
- The rapid expansion of the refining sector in the Middle East, which means that there is relatively little growth in crude oil exports from the region.

Figure 4.15 ▷ Change in crude oil trade by region in the New Policies Scenario



North America becomes the second-largest gross crude oil exporter by 2040, while Asia Pacific's need for crude oil imports intensifies

19. Global oil trade is analysed between the 25 countries and regions for which energy demand is modelled separately in the World Energy Model (see Chapter 1). Crude oil here includes condensate.

- The ever-increasing appetite for crude oil in Asia, with a 9 mb/d increase in the region's crude oil import requirements, combined with reduced imports requirements in Europe and North America, underpinning a profound shift in trade flows.

Taken together, these trends imply the need for a major reappraisal of oil security and the means to ensure it.

Rise of the United States as a major crude exporter

The surge in tight oil output from the United States has already triggered major changes to the dynamics of global oil supply and the oil price. Through a decline in imports and a surge in exports, US tight oil is now having a similarly disruptive impact on global crude oil trade. Crude oil imports to the United States fell by more than 1.3 mb/d between 2010 and 2016 (to 7.9 mb/d), with West African exporters most affected: their exports of light crude oil to the United States fell by 80% over the same period. Concurrently, since the ban on crude oil exports was lifted in late 2015, US crude oil exports have skyrocketed to over 0.9 mb/d (in the first-half of 2017) and have expanded their range of destinations from a single country (Canada) to 27 countries across Latin America, Europe and Asia. The rapid rise in exports was supported by a wide discount of WTI (West Texas Intermediate) against other global oil pricing benchmarks, robust offshore production, cheap tanker rates, and so-called "back-haul economics"[20] that allow the more efficient use of tankers. In a period of relative abundance of oil supplies, increased exports from the United States have intensified competition for market share among exporters.

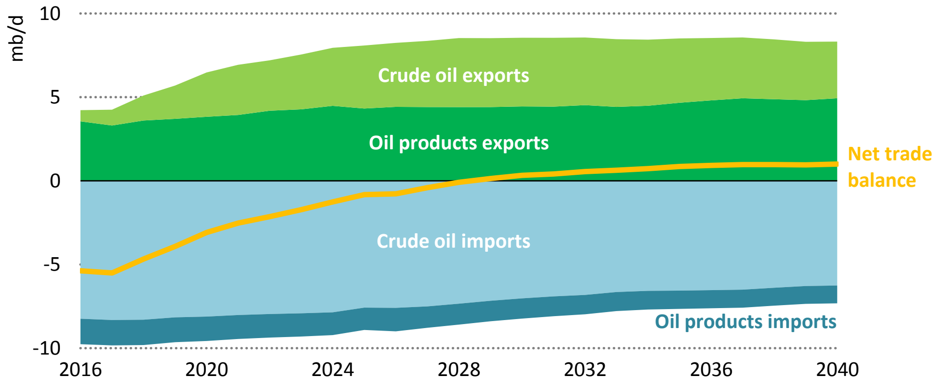
Will this level of US exports be sustained (or even increase) in the long term? With tight oil production set to grow to the mid-2020s in the New Policies Scenario, net crude oil imports into the United States drop from 7.4 mb/d today to 2.9 mb/d by 2040. Meanwhile, net product exports grow from 2.0 mb/d to 3.9 mb/d over the same period thanks in large part to efficiency measures that reduce domestic consumption. This pushes the overall net oil trade balance of the United States into positive territory by the late-2020s. In the New Policies Scenario, the United States therefore becomes a net exporter of all the fossil fuels.

However, in practice the United States remains both a large supplier and a major consumer of crude oil in the New Policies Scenario (Figure 4.16). This is mainly due to US refineries' limited ability to take domestic light crude oil (which is therefore exported) and continued demand from refineries for medium-to-heavy grades (which continue to be imported). Before the emergence of tight oil, US refineries had heavily invested in upgrading capacity and many of them are now best configured to process heavier crude oils, which are imported from the Middle East, Canada or Latin America. Although US refineries have made efforts to process more domestic light crude oil, there are limits to how much further this can go: most refiners who are able do so have already switched, as evidenced by the fact that light crude oil accounted for the bulk of the reduction in US import volumes

20. Tankers carrying crude from the Middle East to the United States used to return empty. US crude oil can now be loaded on those tankers and be sold in Europe on the return journey.

between 2010 and 2016. Although several new condensate splitters are likely to come online, it is unlikely that major new refinery investments geared towards light crude oil will materialise at scale unless there is a significant and persistent discount of domestic prices to international ones. This is what sustains continued crude oil imports (mostly medium-to-heavy oil) over the projection period.

Figure 4.16 ▷ US oil net trade balance in the New Policies Scenario



The United States becomes self-sufficient in oil from the late-2020s, but maintains substantial volumes of export and import at the same time

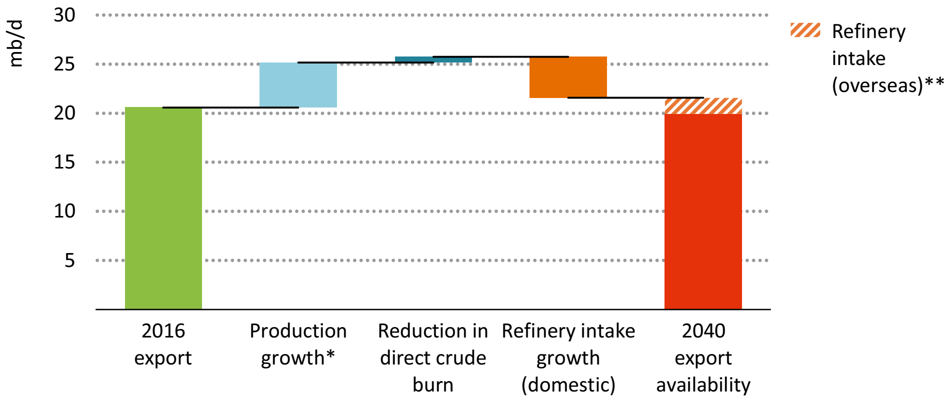
In the New Policies Scenario, gross crude oil exports of the United States reach around 4 mb/d in 2030 before gradually declining to 3.4 mb/d as tight oil production begins to wane, while gross crude oil imports in 2040 remain over 6 mb/d. US crude oil is exported to a range of destinations including Latin America, Europe and Asia. For European refiners, US light crude oil can fill the gap left by declining North Sea crude oil production. For Asian refiners, US crude oil can provide some degree of supply diversification (and a chance to produce more light products), although the long shipping distances make Asia the last destination for US cargoes. United States exports, together with those from Canada and Mexico, means that North America as a whole increases its gross crude export by 4.5 mb/d between 2016 and 2040, becoming the second-largest crude oil exporter after the Middle East.

The Middle East's refined approach

It has been a long-standing ambition of the Middle East to expand into the downstream sector to extract more value from its indigenous oil production and achieve economic diversification (Krane, 2015). This ambition gradually comes to fruition in the New Policies Scenario. With the commissioning of several new refineries, the region is now set to become not only the largest crude oil exporter but also the largest product exporter in the world. Yet in the New Policies Scenario, despite an increase of crude production by 4.5 mb/d between today and 2040, less than 1 mb/d becomes additionally available for exports due to rising consumption within the region and the expansion of refining capacity. Refineries within the Middle East currently consume around a quarter of the region's crude oil production, but the share rises to 34% by 2040 as the region adds more than 4 mb/d of net refining capacity over the *Outlook* period. This tied demand is set to reduce the amount of crude oil available for export to other regions.

However, refining capacity additions within the region are not the only factor affecting the availability of exports. Major Middle East oil producers are also increasingly participating in refinery projects in other parts of the world. For example, Saudi Arabia is currently pursuing a strategy to achieve vertical integration at a global level by taking stakes in refining assets in overseas markets in Asia and North America, which tend to refine crude oil from Saudi Arabia. Saudi Arabia's equity stakes in overseas refineries have already reached around 2 mb/d (including those under construction) and Kuwait and the United Arab Emirates plan to follow suit. By importing crude oil from the Middle East, these refineries are set to benefit from competitive feedstock, while offering stable export outlets for producers. The effect, however, is to reduce the amount of crude oil freely available on the market. Taking account of the demand from overseas refineries where Middle East producers already have an equity stake, which is likely to grow further in the future, the amount of Middle Eastern crude oil available for exports – mostly medium-to-heavy crude oil – could actually shrink over the course of the New Policies Scenario, despite growing production (Figure 4.17). The reduced availability of heavy crude oil and increased supply of light crude oil from other regions is likely to keep light-heavy differentials narrow amid a growing number of complex refineries.

Figure 4.17 ▷ Change in crude export availability in the Middle East in the New Policies Scenario



Despite production growth, crude export availability from the Middle East does not increase by much due to mounting consumption from its own refineries within and outside the region

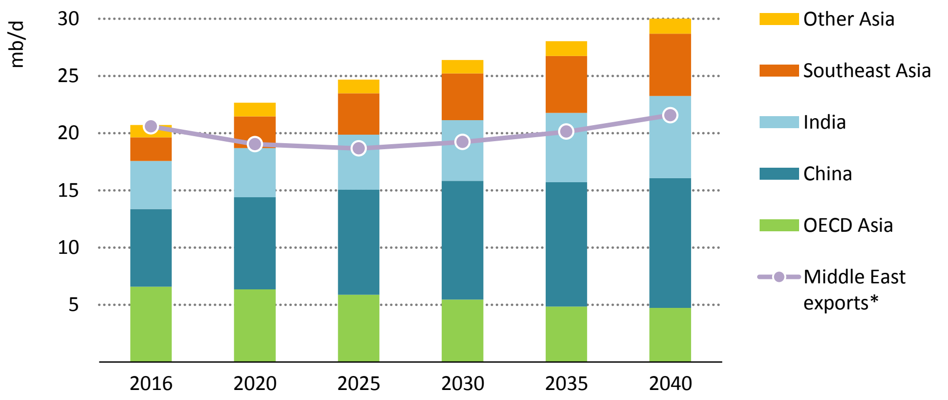
* Crude and condensate part of NGLs. ** Further investments beyond those already under construction are not considered; only capacity corresponding to the equity shares of Middle East producers is considered.

The Middle East's strategic reorientation in favour of refined products has significant ramifications for Asia, the final destination of an increasing share of global crude oil shipments, where import requirements are projected to continue their rapid upward path and where refineries increasingly compete with the Middle Eastern refineries.

Asia's inexorable appetite for crude

The Asia Pacific region accounts for the lion's share of oil demand growth over the coming 25 years, and not surprisingly, the same is true for crude oil imports. In the New Policies Scenario, Asia Pacific's combined crude oil import needs rise by 9 mb/d to around 30 mb/d by 2040, with strong growth in China, India and Southeast Asia more than offsetting declines in Japan and Korea. Asia Pacific's share of global crude oil imports rises from 50% today to 67% by 2040, underpinning an accelerated growth of eastward trade flows (Figure 4.18).

Figure 4.18 ▷ Asia Pacific crude oil imports and the Middle East's export availability in the New Policies Scenario



Asia Pacific crude oil import needs increase by 9 mb/d by 2040, outpacing the available exports from the Middle East

* Does not include demand from overseas refineries where Middle East countries have stakes.

The abundance of oil supply in recent years has made traditional exporters vie for market share in growing Asian markets. As the United States emerged as a crude oil exporter, a considerable amount of crude oil in the Atlantic Basin displaced from North America flowed towards Asia. Russia also sent increasing volumes of oil through its East Siberia Pacific Ocean pipeline and in some months overtook Saudi Arabia as the leading crude oil supplier to China. Against this backdrop, Saudi Arabia repeatedly cut its official selling prices for Asia to defend market share. These dynamics have provided some degree of comfort to Asian importers but recent relief should not be interpreted as a lasting sign of improved oil security. The rapid increase in crude oil import needs in the New Policies

Scenario along with the reduced availability of crude oil from traditional exporters point to tougher times ahead. The expanding volume of exports going through the Strait of Malacca, the world's second-busiest trade chokepoint, adds another layer of complexity to Asian importers' oil security concerns.

In the past, Asia's total crude oil import needs were less than the crude oil exports of the Middle East, but the gap has narrowed and the situation is reversed in the New Policies Scenario. This means that, while strengthening strategic ties with their largest suppliers in the Middle East, Asian importers increasingly tap into other sources. Exports from the United States will help to some extent, but this relief will be limited by the long distances involved, and by the limited extent to which US exports can meet demand for the medium-to-heavy grade crude oil, which represents a major part of Asia's needs.

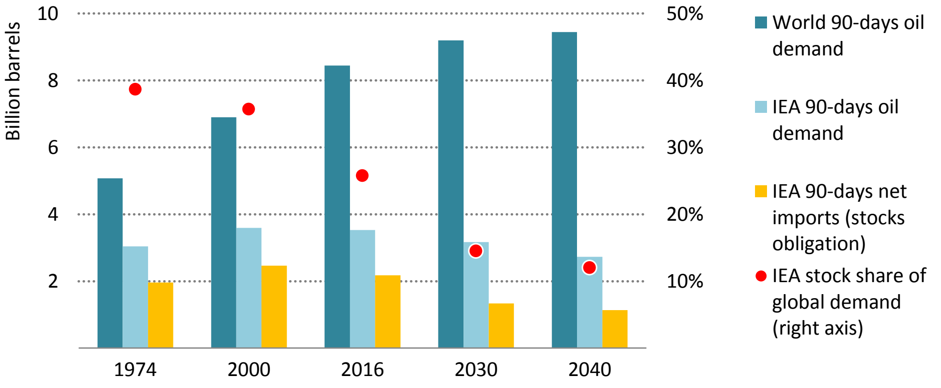
Oil products trade trends

Global oil products trade grows by 2.7 mb/d between 2016 and 2040 in the New Policies Scenario to around 17 mb/d in 2040. As with crude oil trade, the United States emerges as a key product exporter, sending around 5 mb/d of oil products by 2040 – chief among them gasoline, LPG and naphtha – to the Atlantic Basin but also to Asia. This surge in US product exports weakens the case for refining investment in Latin America, keeping the region's product balance in negative territory throughout the *Outlook* period. Europe's product balance worsens over the next ten years due to rising diesel imports, but the deficit gradually reduces in the longer term as demand shrinks. The Middle East and Asia march in opposite directions. The Middle East becomes the largest oil product exporter, increasing its product export by two-thirds over the projection period. The region sends an increasing amount of gasoline, naphtha and LPG to Asian markets, while competing with Asian refiners for diesel exports to European markets. Despite adding more than 9 mb/d of new refining capacity to 2040, Asia Pacific's net oil product import needs expand by a further 3 mb/d between 2016 and 2040. Unsurprisingly, gasoline and diesel remain the most traded products over the *Outlook* period in the New Policies Scenario, but LPG trade shows the largest growth as its use as a petrochemical feedstock expands across the world.

Implications for oil security: a fresh approach in tomorrow's new market environment

The prolonged period of low oil prices has alleviated some concerns over oil security in many oil-importing countries. In the future, however, challenges are looming as Asia's oil import needs and the Middle East's export availability head in different directions. As set out in last year's *Outlook,* there is also the possibility of a market imbalance in the 2020s as a result of the current low levels of upstream investment: indeed the challenge from inadequate investment is present even in the Sustainable Development Scenario (where oil demand peaks around 2020). As always, there is also a risk of supply disruptions due to natural disasters or geopolitical events. For example, Hurricane Harvey in late August 2017 caused more than 15% of US refining capacity to go offline for several weeks, interrupted around 700 kb/d of crude oil production and caused numerous problems for oil pipelines and terminals along the US Gulf coast, underlining that reduced oil imports do not eliminate vulnerability to supply interruptions. In the New Policies Scenario, spare production capacity to cushion the impact of potential crises continues to be concentrated in Saudi Arabia meaning that geopolitical events in the Middle East will continue to have a major influence on global oil markets.

Figure 4.19 ▷ 90-days oil demand and stockholding coverage of IEA member countries in the New Policies Scenario



Under the New Policies Scenario, the stockholding obligation of IEA member countries would cover just 11 days of global oil demand in 2040

Notes: Stock share = IEA stockholding obligation as percentage of 90-days global oil demand. Mexico is included in data for IEA member countries for projected years.

So far, a key instrument in the international toolkit to safeguard oil security has been the possibility of a co-ordinated release of emergency oil stocks by IEA member countries. However, the changing oil market landscape requires changes in this mechanism if it is to retain its effectiveness. Since its founding in 1974, the IEA has co-ordinated an emergency response system which obliges its member countries to hold oil stocks corresponding to at least 90-days of their net-imports and release them in a co-ordinated manner in the case of major physical interruptions to supply. While the system has so far provided an important safety net and mitigated the effect of various disruptions, waning oil demand in many IEA member countries and surging demand in emerging countries means a risk that the system will become progressively less effective, thereby making the whole global energy system more vulnerable. When founded in 1974, the stockholding obligation of IEA member countries represented around 40% of 90-days of global oil demand. This share fell to 26% in 2016 and, under the New Policies Scenario, would fall further to 12% by 2040 (covering 11-days of global demand), too short to compensate for a large disruption in supply (Figure 4.19). Therefore, there is a strong case to broaden the IEA oil security umbrella, in order to cover the contingencies that might arise in tomorrow's oil market. One option would be to bring the rising oil-consuming countries – many of which are now

Association countries of the IEA[21] – closer to the collective oil security system in a gradual and inclusive manner. Aggregate demand from IEA members and today's seven Association countries would account for around 60% of global oil demand in 2040.

Around 230 million barrels of oil storage capacity is currently under construction or expansion worldwide, and some 400 million barrels of storage capacity is planned. A large part of this is located in Asia and is operated by private companies (IEA, 2017c). In theory, expanded storage capacity could provide a buffer to supply disruptions, thereby contributing to improved oil security. However, storage capacity operated on a purely commercial basis may not always make such a contribution: operations typically are based on expectations about future price movements, not on the prevailing supply-demand balance. For example, in the case of physical disruptions to supply, if companies expect the trend to be sustained, they may accumulate more stocks to exploit larger profits in the future, essentially aggravating the supply-demand imbalance and inducing greater volatility in the market. Increasing commercial storage capacity therefore does not remove the need for a mechanism aimed at ensuring the provision of a public good.

While the emergency response system is critical to mitigate the impact of potential interruptions to supply, a coherent approach to oil security needs to cast its net more widely to encompass: the adequacy of investment in future supply, regular dialogue between producers and consumers, and measures to curb demand via greater efficiency or fuel switching. In this regard, the current period of lower oil prices offers an opportunity to remove fossil-fuel subsidies, which are still prevalent in many parts of the world (see Chapter 2), in order to provide incentives for investment in more efficient technologies and to create greater demand responsiveness in times of oil shortage. As discussed earlier in this chapter, countries are pushing ahead with policies to promote greater efficiency in the road freight sector and the electrification of passenger transport, with significant implications for future consumption patterns. Yet even if these efforts intensified to the extent that the world soon reached a peak in oil demand (as envisaged in the Sustainable Development Scenario), this would not remove the need for vigilance on oil security (Box 4.5).

Box 4.5 ▷ Oil security in the Sustainable Development Scenario

In the transition to a low-carbon world, as set out in our Sustainable Development Scenario, global oil consumption peaks around 2020 and declines to 73 mb/d by 2040. Asia, the epicentre of today's demand growth, also sees its oil demand peak around the mid-2020s. Lower oil demand brings lower import requirements and – coupled with lower prices – lower import bills, easing the cost burden for importing countries. In the Sustainable Development Scenario, Asia's overall oil import requirement (both crude and oil products) increases by less than 3 mb/d between 2016 and 2040, considerably lower than the 12 mb/d rise seen in the New Policies Scenario.

21. Brazil, China, India, Indonesia, Morocco, Singapore and Thailand are IEA Association countries.

However, reduced import needs do not necessarily mean that oil security concerns vanish. Even in a scenario in which demand falls by 1.7% per year in the 2030s, there is still a substantial need for upstream investment to compensate for falling production from existing fields (where observed declines in post-peak fields average more than 6%).[22] We estimate that around $5.8 trillion would still be required in upstream oil investment between 2017 and 2040, even in the Sustainable Development Scenario. Furthermore, the risks from geopolitical developments and from natural disasters would not go away: indeed, the risks of geopolitical disruption may be greater in a world where major producers have to cope with significant reductions in hydrocarbon revenues. Meanwhile, reliance on production and exports from the Middle East, the largest source of low-cost oil, remains as high as in the case of the New Policies Scenario. Maintaining a well-functioning oil security mechanism is therefore no less important in the carbon-constrained world of the Sustainable Development Scenario than it is in the New Policies Scenario.

4.3.5 Investment

The oil and gas sectors in the New Policies Scenario require cumulative investment of some $21 trillion between 2017 and 2040, three-quarters of which is in the upstream sector (Table 4.10). Upstream capital spending therefore needs to average around $640 billion every year to avoid potential mismatches between supply and demand. This figure takes into account the need to meet growing oil and gas demand while compensating for underlying declines in existing sources of production, changes in the type and location of projects that are executed, technological progress that expands the resource base and reduces costs, and the evolution of unit costs (see section 4.3.2). The $640 billion in annual upstream spending is a decrease on the investment required in the *WEO-2016* ($700 billion per year), reflecting lower costs to 2040 in this year's *Outlook* and the larger resource base, offset to some extent by higher levels of oil and gas demand. Upstream investment needs increase over the course of the New Policies Scenario from an annual average of $535 billion in the period to 2025 to $710 billion between 2025 and 2040. The investment needs over the next ten years are around 25% greater than levels seen in 2016 (and anticipated in 2017) although they remain significantly below the peak level seen in 2014 of nearly $800 billion.

22. Decline rates and the ongoing need for new upstream investment were analysed in detail in the *WEO-2016* .

Table 4.10 ▷ Cumulative oil and gas supply investment by region in the New Policies Scenario, 2017-2040 ($2016 billion)

	Total oil and gas	Upstream oil and gas	Transport		Refining oil	Annual average upstream oil and gas
			Oil	Gas		
North America	5 419	4 407	156	692	164	184
Canada	1 085	925	37	108	16	39
United States	3 596	2 839	91	535	130	118
Central & South America	1 944	1 648	95	120	81	69
Brazil	1 015	870	61	35	49	36
Europe	1 623	1 127	18	362	116	47
Africa	1 930	1 593	92	165	80	66
Middle East	3 033	2 283	211	325	215	95
Eurasia	2 611	2 141	56	349	65	89
Russia	1 714	1 350	32	279	53	56
Asia Pacific	3 606	2 220	85	767	534	92
China	1 516	1 049	21	256	190	44
India	445	203	26	80	136	8
Southeast Asia	775	496	21	128	130	21
Shipping	445	n.a.	312	133	n.a.	n.a.
World	**20 611**	**15 418**	**1 024**	**2 912**	**1 256**	**642**
Non-OPEC	n.a.	11 878	n.a.	n.a.	n.a.	495
OPEC	n.a.	3 541	n.a.	n.a.	n.a.	148

Outlook for coal

Fire and rain?

Highlights

- Against a background of falling coal use in Europe, the United States and China, global coal demand fell by 2% in 2016, for the second year in a row. In the New Policies Scenario, consumption flattens at around 5 500 Mtce over the period to 2040, a stabilisation that is the product of counterbalancing trends: coal demand keeps falling in Europe (-61%), China (-13%) and the United States (-11%), but these declines are offset by increases in some developing countries, especially in India and Southeast Asia.
- In 2015, India overtook the United States as the second-largest coal consumer and its coal use more than doubles to 1 230 Mtce in 2040 in the New Policies Scenario. However, coal faces strong competition, in particular from solar PV, the costs of which have been declining rapidly. With policy-makers looking to limit reliance on imported energy and India's domestic output projected to grow at an annual rate of nearly 4%, import growth of 45% is significantly lower than in the *WEO-2016*.
- China's coal industry restructuring is central to coal market dynamics. Various policies to manage the level of production have been implemented with the aim of keeping China's coal prices in a band of $80-90/tonne, a price level acceptable to power companies, while providing a sufficient margin for most coal mines to stay in business. The influence of China's coal prices on global prices through arbitrage and trade sees international steam coal prices rise to over $80/tonne in 2025 and then to $86/tonne in 2040 in the New Policies Scenario.
- Inter-regional coal trade stands at 1 010 Mtce in 2040, which is just below the level of 1 050 Mtce in 2016. Indonesian exports drop by some 45% as domestic use is prioritised and output growth is restricted. US exporters, with relatively high costs, also see their shipments dropping (-25%) while exports from Colombia, far from the growth markets in Asia, are flat. With plenty of low-cost coking coal, Australia expands its exports over the coming 25 years (+19%) while Russian exports, benefiting from the fall in the rouble, also increase (+13%). Declining domestic needs and proximity to growth markets underpin export growth of 20% in South Africa.
- Carbon capture and storage – an indispensable technology for the future of coal in scenarios that meet climate goals – has made limited progress in demonstrating its commercial viability in recent years. It is however an essential component of action to deliver the goals incorporated in the Sustainable Development Scenario, which sees some 210 GW of coal plant worldwide being fitted with CCS by 2040, implying that efforts to help it to become commercially viable need to be stepped up.

5.1 Recent market and policy developments

Despite all the obituaries being written for coal, it was one of the most successful commodities of 2016 for many traders and market participants. Coal prices soared, with steam coal prices in the fourth-quarter of 2016 on average 50-60% higher than in the fourth-quarter of the previous year, and coking coal prices an astounding 200% higher than in the fourth-quarter of 2015. But the rise in financial fortunes was not reflected in much positive news for the industry from the demand side. Coal remained under pressure in many of the world's largest markets. Consumption declined in the US power sector, with 2016 being the first year ever in which more electricity was generated in the United States from natural gas than from coal. A combination of policies (e.g. the UK carbon price floor) and market forces (low gas prices and higher coal prices) also led to a marked fuel switch from coal to gas in the power sector in the European Union. The load factors of coal plants in India continued to drop as new capacity coming online exceeded power demand growth, and the Chinese authorities put a number of advanced coal plant projects on hold.

So what propelled coal prices upwards last year? With global coal demand having declined in 2016 – for the second year in a row – the answer to this question lies almost exclusively on the supply side. Facing severe overcapacity, coal producers around the world reacted by cutting costs, making their businesses leaner, reassessing their core strategies and reducing capacity. In the United States, the two largest coal producers, Peabody Energy and Arch Coal, sought bankruptcy protection, from which they have since emerged. In Australia, exporters stringently maintained cost discipline, while in Indonesia many high-cost producers idled mines. From this vantage point, the global rebalancing process carries all the features of one of the classic commodity cycles that regularly shakes the extractive industries.

This cycle, however, is distinctive, because the speed and the magnitude of the price rebound are not primarily determined by market forces, but are due to direct and conscious policy interventions in China – the country that is home to the world's largest coal industry (see Chapter 14). In 2015, some 80% of Chinese coal companies were making losses. A market-based rebalancing would have risked large layoffs as well as a financial crisis because bankrupt coal companies' loans (many of which were granted by Chinese state-owned banks) remained unsettled. The Chinese authorities chose instead to introduce a set of measures to cut capacity and manage production. The reduction of annual working days from 330 to 276 was particularly effective: introduced in April 2016, it immediately reduced production by up to 15%, propelling coal prices some 40% upwards within five months. The surge in domestic prices increased China's imports, which led to a rise in coal prices around the world.

The profitability of the world's export-oriented coal industry remains – at least over the coming ten years – highly dependent on China's policy efforts to restructure its coal industry. To date, imports to China appear to be seen as a welcome source of flexibility. But there are also voices in China pushing for tighter import controls (often via quality restrictions, some of which have already been implemented). Uncertainty about coal demand growth in India is rising, due to subdued power demand growth and rapid declines in the cost of solar photovoltaic (PV) generation, while the government reiterates its determination to reduce reliance on imports. The new administration in the United States has been vocal about its willingness to support the domestic coal industry, and policy changes such as the review of the Clean Power Plan (the impact of which is now no longer considered in the New Policies Scenario) certainly affect the future prospects of coal in the country. But the primary competitor for coal in the United States is inexpensive natural gas, the resource estimates of which appear to be growing with each revision or new assessment (see Chapter 9). Whether a rise in US liquefied natural gas (LNG) exports brings domestic gas prices to a level that allows coal producers to compete is a key question for the US coal market. Southeast Asia is often accepted as an undisputed growth engine for coal demand, but public opposition against coal projects – mostly on environmental grounds such as concerns about local air pollution – is growing. Coal's main advantage in Asia, its cost-competitiveness, is challenged by the falling cost of renewables and, to an extent, by low-cost LNG, so strong growth cannot be taken for granted here either.

These developments need to be seen against the backdrop of the Paris Agreement which aims to limit the global rise in temperature to well below 2 degrees Celsius (°C). In this context, coal's future is increasingly tied to the technical and commercial feasibility of carbon capture and storage, and to its public acceptance.

5.2 Trends to 2040 by scenario

5.2.1 Market dynamics to 2025

China's administered coal industry restructuring plays a central role in coal market dynamics through the early 2020s. Various policy measures to actively manage the level of production have been announced with the aim of keeping steam coal prices in a narrow band of \$80-\$90/tonne.[1] This is understood to be the sweet spot where prices are acceptable to the power generators and industrial coal consumers while providing a sufficiently high margin for most coal companies to stay in business. Our outlook for coastal Chinese prices, \$84/tonne in 2020 and \$87/tonne in 2025, falls within the targeted range.

Coal demand growth is projected to remain subdued in the coming ten years. Global coal consumption reaches 5 490 million tonnes of coal equivalent (Mtce) in 2025, up from 5 365 Mtce in 2016, but still 120 Mtce below the level reached in 2014. China's coal demand drops slightly, reaching 2 725 Mtce in 2025, down from 2 800 Mtce in 2016. A rise in natural gas prices in the United States helps coal to gain some ground against gas in US power generation. Nevertheless, US coal demand in 2025 is projected to end up at

1. The targeted price bandwidth is Renminbi (CNY) 500-570/tonne (5 500 kilocalories per kilogramme [kcal/kg], net) at the Bohai rim (e.g. Qinhuangdao and other ports in that region). Depending on how far prices exceed or fall below this range, the National Development and Reform Commission has announced different measures that could be implemented to stabilise prices. These include the working day rule, but also the approval of new mining capacity or additional capacity closures.

460 Mtce, some 20 Mtce below 2016 levels. As energy demand growth picks up, India sees its coal demand rise to over 800 Mtce in the coming decade (up from 575 Mtce in 2016), together with Southeast Asia, where coal demand increases to over 250 Mtce in the same time frame (up from 160 Mtce today). These two regions are the primary areas of growth in an otherwise subdued global coal market.

In a market that is still characterised by overcapacity, investment activity concentrates on sustaining production in existing operations or on projects that are underway but not yet completed. In China some 440 million tonnes per annum (Mtpa) of mining capacity has received partial or full approval and is scheduled to gradually come online in the next decade. Although these projects still require considerable capital expenditure, the amount of capital invested over the coming ten years will be an order of magnitude lower than in the past decade. Export-oriented greenfield projects are rare. With the exception of the potentially huge Carmichael project in Australia's Galilee basin and another project in the Surat basin, most projects geared towards exports are either small or target coking coal. India, where coal production continues to grow and new mines are being opened at a rate that is unmatched elsewhere in the next decade, is the only country that sees investment increasing markedly in the period to 2025.

5.2.2 Long-term scenarios to 2040

The New Policies Scenario is the main scenario of this *World Energy Outlook (WEO)*. In this scenario, the coal price relative to that of other fuels, together with policy, macroeconomic and demographic assumptions means a dampening of the growth prospects for global coal consumption over the next 25 years. By the mid-2020s coal demand has returned to 2015 levels, and the 5 610 Mtce demand level reached in 2040 corresponds to the level reached in 2014 (the recent peak year), translating into an average annual growth rate of 0.2% per year between 2016 and 2040 (Table 5.1). Over the past 25 years coal demand grew, on average, by 2% per year, so this represents a major change in trends, reflecting the rapidly falling cost of renewables and the increasing focus on environmental issues by policy-makers around the world. Among the fossil fuels, coal currently ranks second after oil in terms of global primary energy supply, with a share of 27%. However, coal falls back in the mid-2030s, as its share drops to less than a quarter, and gas becomes the second-largest supplier of primary energy. The headwinds that coal faces however are still not strong enough in this scenario to keep coal demand on a declining trend in a growing global energy market. Although global coal demand growth is sluggish, maintaining production and offsetting depletion requires cumulative capital expenditure of $1 trillion for mines and coal supply infrastructure over the *Outlook* period.

The Current Policies Scenario, which is based solely on measures and policies already in force, sees global coal demand expanding much more rapidly, at an annual average rate of 1.2% to 2040 (Figure 5.1). This scenario is characterised by less stringent environmental policies, notably in terms of CO_2 emissions reduction and mitigation of local air pollution. Without the impact of new policies constraining coal use, commercial considerations mean that coal demand growth quickly re-emerges from the current slump. Despite a slight drop in its share of primary energy supply to 26% in 2040, coal retains the rank of the second most important source of primary energy, in the Current Policies Scenario, over the *Outlook* period. With 34% of electricity produced from coal in 2040, it remains the primary fuel for power generation in the Current Policies Scenario, ahead of renewables (31%) or gas (25%). In high-income countries and regions, where environmental protection is already deeply ingrained in energy policy, coal demand declines in this scenario as it does in the New Policies Scenario. In many developing countries in Asia and Africa, however, coal thrives. Growth in coal demand and depletion of coal mines requires cumulative investments of $1.3 trillion in the Current Policies Scenario (some 30% more than in the New Policies Scenario). There is significant greenfield investment and expansion into untapped coal basins, and coal prices increase to $100/tonne in 2040 (the coal price here meaning the OECD steam coal import price, a weighted average of prices paid by key importers in the OECD, including handling fees at the import port and inland delivery).

Table 5.1 ▷ World coal demand, production and trade by scenario (Mtce)

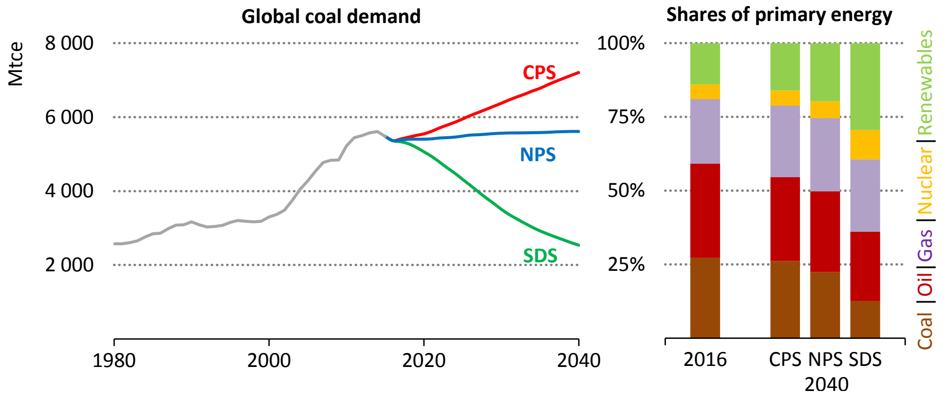
			New Policies		Current Policies		Sustainable Development	
	2000	2016	2025	2040	2025	2040	2025	2040
Demand	**3 301**	**5 364**	**5 488**	**5 613**	**5 950**	**7 208**	**4 318**	**2 539**
Power generation	2 236	3 320	3 339	3 359	3 731	4 693	2 311	826
Industrial use[2]	856	1 714	1 854	2 040	1 902	2 240	1 733	1 580
Other sectors	209	330	295	214	318	274	274	132
Power generation share	*68%*	*62%*	*61%*	*60%*	*63%*	*65%*	*54%*	*33%*
Production	**3 254**	**5 271**	**5 488**	**5 613**	**5 950**	**7 208**	**4 318**	**2 539**
Steam coal	2 504	4 049	4 319	4 574	4 734	6 040	3 300	1 834
Coking coal	449	967	900	806	923	875	826	595
Lignite*	301	255	269	233	293	293	193	110
Steam coal share	*77%*	*77%*	*79%*	*81%*	*80%*	*84%*	*76%*	*72%*
Trade**	**471**	**1 046**	**1 004**	**1 009**	**1 167**	**1 336**	**783**	**529**
Steam coal	310	756	735	721	875	1 023	546	309
Coking coal	175	292	280	306	301	329	248	233
Production which is traded	*14%*	*20%*	*18%*	*18%*	*20%*	*19%*	*18%*	*21%*

* Includes peat. ** Total net exports for all WEO regions, not including intra-regional trade.

Notes: Historical data for world demand differ from world production due to stock changes. Trade does not match the sum of steam and coking coal as a region could be a net exporter of one coal type but a net importer of another.

2. Unless otherwise stated, coal use in industry in this chapter reflects volumes also consumed in own use and transformation in blast furnaces and coke ovens, petrochemical feedstocks, coal-to-liquids and coal-to-gas plants.

Figure 5.1 ▷ Global coal demand and share of coal in world primary energy demand by scenario



The stringency of environmental policy determines the future fortunes of the coal market

Note: CPS = Current Policies Scenario; NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

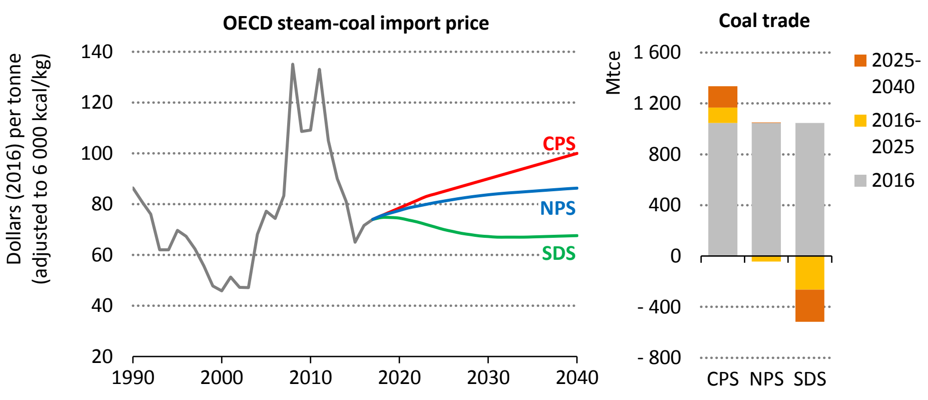
The Sustainable Development Scenario reflects the energy components of the UN Sustainable Development process and takes a different approach. It starts with a vision of where the energy sector needs to stand in 2040 to achieve three policy goals – urgent action on climate change consistent with the Paris Agreement, achieving universal access to modern energy by 2030 and significantly reducing air pollution – and then maps how to achieve them. The goals of this scenario are not compatible with unabated coal use, and thus global coal demand falls by 3% per year, on average, over the *Outlook* period.

The question of carbon capture and storage technology (CCS) looms large in this scenario. With the Petra Nova project in Texas completed in early 2017, the second large-scale coal power plant equipped with CCS has become operational. China has also begun construction of its first large-scale CCS project, at a coal-to-chemicals plant in Shaanxi province. Despite these achievements, global progress in commercialising CCS technology is lagging. The Kemper County Energy Facility in the United States, a planned integrated gasification combined-cycle plant fitted with a CCS system will be turned into a natural gas plant project in the wake of technical issues, delays and cost overruns attributed to the new coal gasification technology.

Although CCS is not only about coal, the slow progress in commercialising coal-based applications of CCS technologies is a particularly alarming signal for the coal industry, because CCS is the main lifeline for continued use of coal in the Sustainable Development Scenario. Much of the investment in CCS projects to date has been underpinned by factors such as revenue from enhanced oil recovery, and deployment at the scale and pace needed will not happen in the absence of supportive policy frameworks. Given the significant possibility of strengthened climate policies in the future, industry has a major interest in seeing faster progress on CCS. Governments, too, have a critical role to play in developing and underwriting early investment in CO_2 storage facilities and multi-user transport infrastructure, and in developing policies and incentives which address the additional operating costs associated with CO_2 capture, although the scale of the support required can vary considerably across CCS applications. Industrial processes which produce CO_2 streams with high purity may provide an opportunity for early CCS deployment with relatively limited government intervention.

By 2040, some 210 gigawatts (GW) of coal plants are fitted with CCS worldwide in the Sustainable Development Scenario, 150 GW of which is in China. Coal's share in primary energy supply drops to 13% in 2040, far behind renewables (29%) and gas (25%). Some 6% of global electricity generation is still based on coal by 2040, but almost 60% of this comes from plants equipped with CCS. There are few alternatives to coal readily available in steel production, and therefore coking coal demand remains slightly more robust than steam coal demand, but it also declines at an average annual rate of 1.9%. International coal trade consequently becomes weighted towards coking coal over time. Despite the bleak prospects for the fuel, coal investment does not grind to a halt in the Sustainable Development Scenario, since existing mines are depleted faster than demand drops. Cumulative investments in coal supply still amount to $635 billion in the period to 2040, spent on sustaining production in existing operations and compensating for depletion.

Figure 5.2 ▷ Average OECD steam coal import price and global coal trade by scenario



Through the mid-2020s, coal prices remain influenced by China's policies on coal supply

Note: CPS = Current Policies Scenario; NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

The coal market faces very different fortunes in the three scenarios. The three coal price trajectories that establish the balance between supply and demand, however, all follow two main phases (Figure 5.2). Through the mid-2020s, coal prices keep increasing, underpinned by production control measures in China to keep domestic coal prices within a target range of $80-90/tonne. Chinese coastal coal prices are at the lower end of this spectrum in the

Sustainable Development Scenario and at the higher end in the Current Policies Scenario. These prices feed through to the international market via arbitrage opportunities (see Chapter 14). From the mid-2020s through 2040, coal prices follow a long-term evolution that reflects the fundamentals of the respective scenario. The price increase over the next few years is marginal in the Sustainable Development Scenario, compared to the other two scenarios, as the decline in demand allows for the closure of some high-cost mines that are not needed. Only the least-cost mines can survive, and the pressure to improve productivity is particularly high. The gradual increase in prices in the latter half of the period in the New Policies Scenario and the Current Policies Scenario reflects upward pressure on costs (more challenging geological conditions, increasing costs for consumables like fuel, and the need to tap more remote deposits).

5.3 A closer look at the New Policies Scenario

5.3.1 Demand

Regional trends in demand

Historically, coal demand growth and gross domestic product (GDP) growth have been closely aligned, but we see this relationship changing in the New Policies Scenario. While global GDP grows by 3.4% per year on average over the next 25 years, coal demand growth levels off. However, the global trend masks some stark regional differences. Many high-income countries, often with largely flat energy demand and an economic growth model that relies to a large degree on services, choose to phase out coal use for environmental reasons. However, lower income countries at an earlier stage of their economic development typically need to satisfy fast growing energy demand fuelled in part by rapid population growth. For this group of countries, coal is often a fuel of choice, as it is inexpensive, scalable, relatively secure, easily storable and, in the case of domestic coal, brings employment benefits for local workers.

India, Pakistan, Bangladesh and parts of Southeast Asia all fall into the latter group of economies and these countries become the primary engines of future coal demand growth (Table 5.2). Coal demand in India more than doubles over the period to 2040, while in Southeast Asia it grows almost two-and-a-half times.[3] This contrasts with a drop in coal consumption by 2040 of over 60% in the European Union, more than 30% in Japan, and around 10% in the United States. As China's policy efforts to foster the economic contribution of the service sector and decrease reliance on the heavy industries bear fruit, the country gradually joins the group of countries that see their coal demand decline over the projection period. Although China's coal demand peaked in 2013, it takes time to achieve deep cuts in coal consumption. Only in the latter half of the *Outlook* period does China's coal demand drop markedly, resulting in an overall decrease in coal use of some 13% over the next 25 years.

3. Even in the Sustainable Development Scenario, coal consumption in both India and Southeast Asia continues to grow over the medium term before peaking in the mid-2020s.

Table 5.2 ▷ Coal demand by region in the New Policies Scenario (Mtce)

	2000	2016	2025	2030	2035	2040	2016-2040 Change	CAAGR
North America	817	525	481	466	455	439	- 86	-0.7%
United States	762	480	462	452	442	426	- 54	-0.5%
Central & South America	29	49	53	55	57	60	11	0.8%
Brazil	19	24	24	24	25	25	0	0.1%
Europe	578	464	383	327	266	244	- 219	-2.6%
European Union	459	342	269	218	159	135	- 208	-3.8%
Africa	128	151	160	167	178	201	51	1.2%
South Africa	117	134	130	123	117	113	- 21	-0.7%
Middle East	2	4	7	8	9	9	5	3.7%
Eurasia	202	212	221	219	222	220	8	0.1%
Russia	171	157	155	148	149	142	- 15	-0.4%
Asia Pacific	1 544	3 960	4 184	4 324	4 397	4 439	480	0.5%
China	955	2 796	2 726	2 676	2 576	2 437	- 358	-0.6%
India	208	574	800	952	1 097	1 228	654	3.2%
Japan	139	168	149	137	126	116	- 52	-1.5%
Southeast Asia	45	161	252	297	339	387	227	3.7%
World	**3 301**	**5 364**	**5 488**	**5 566**	**5 584**	**5 613**	**249**	**0.2%**

Note: CAAGR = Compound average annual growth rate.

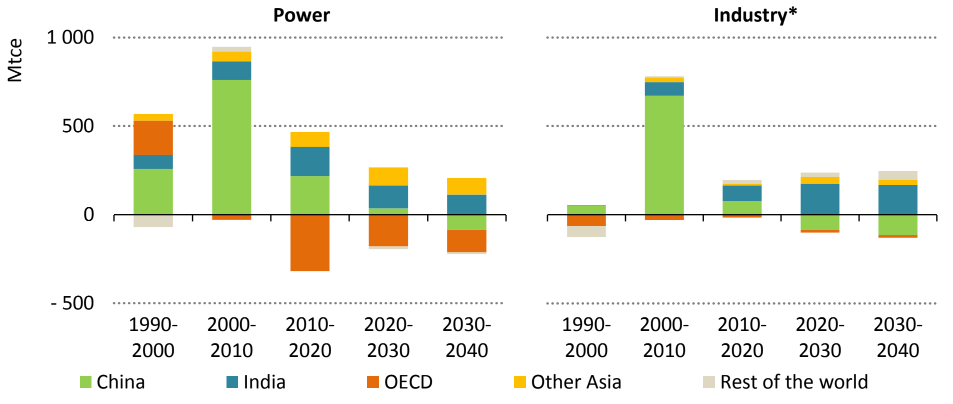
Globally, 1.1 billion people still lack access to electricity today. In the New Policies Scenario, the situation is projected to improve markedly in the coming 15 years, with over 600 million people getting access to power.[4] Expansion of the centralised electricity grid remains the primary means for electrification as it usually offers the least-cost option per kilowatt-hour of electricity for those within easy reach of existing networks. Over half of those who gain access in our *Outlook* do so via a connection to a centralised grid. Where access is provided through the grid, coal plays an important role in supplying the additional electricity. In India and Southeast Asia, for example, where by 2030 almost everyone has access to electricity, coal accounts for 23% of the electricity supplied to those who gain access in India, and 18% in Southeast Asia. In sub-Saharan Africa, which is less reliant on coal and has a stronger focus on off-grid solutions, coal supplies just under 15% of the electricity provided to those who gain access by 2030. In the New Policies Scenario, many people still remain without access to electricity even after 2030, concentrated primarily in sub-Saharan Africa, whereas in the Sustainable Development Scenario universal access is achieved by that time, with a much lower contribution from coal.

4. Access numbers in this paragraph discuss the time horizon to 2030 as this is the end date for the Sustainable Development Goals and the time frame shown in the *Energy Access Outlook: from Poverty to Prosperity, World Energy Outlook Special Report* (IEA, 2017a).

Sectoral trends in demand

Power generation and industry – with steel and cement production at the forefront – are the main consumers of coal, accounting for 62% and 32% of the global coal use respectively. The share of coal use in the power sector drops by two percentage points, while that of industry increases to 37% in 2040. Coal burn in the buildings, transport and agriculture sectors is rare today and diminishes further over the *Outlook* period. Coal is the primary fuel for power generation today, accounting for 37% of the world's power output, but this share drops to around a quarter in 2040, as renewables continue their ascent and become the number one source of power generation in the mid-2020s. Electricity generation from coal increases by some 10% through 2040, but coal burn in the power sector hardly increases, a clear sign that the world's coal fleet becomes more efficient. Three-quarters of the 880 GW of new coal plant entering into service over the next 25 years uses either supercritical (440 GW) or ultra-supercritical technology (235 GW), bringing down the share of the less efficient subcritical plants in the global coal fleet from over 60% in 2016 to less than 40% in 2040. With growing shares of variable renewables, new plants need to be designed with flexibility criteria in mind – including ramping capability, minimum load requirements, part-load efficiency losses and start-up times – but the existing fleet can, often with minor retrofitting investments, also become more flexible (IEA, 2014).

Figure 5.3 ▷ Incremental coal demand by key sector and region in the New Policies Scenario



Coal use is propelled by power generation, steel and cement production in India and other Asian countries while coal use in China has entered long-term decline

* Includes own use and transformation in blast furnaces and coke ovens, petrochemical feedstocks, coal-to-liquids and coal-to-gas plants.

Coal consumption in industry grows by 20% over the period to 2040, with notable regional variations. China reduces its industrial coal use as it substitutes coal with other fuels and technologies (Figure 5.3). While coal consumption increases strongly in the chemical industry and in the production of synthetic fuels, gas use grows strongly in light industry branches, pushing out coal, and electric arc furnaces (based on scrap and electricity) grow strongly in steel production, displacing basic-oxygen furnaces (which use coke). In contrast, steel output in India more than quadruples and cement production triples over the next 25 years, causing industrial coal demand to grow sharply. India becomes the primary source for industrial coal consumption growth (including strong growth of coal demand in light industry).

5.3.2 Supply

Reserves and resources

The world is not short of coal: 1 030 billion tonnes of proven reserves (coal that is known to exist and thought to be economically exploitable with today's technology) are more than sufficient to meet any plausible level of coal demand over the *Outlook* period (and well beyond). In our New Policies Scenario, around 180 billion tonnes of coal are produced cumulatively over the next 25 years, exploiting less than a fifth of the world's coal reserves. The current estimate of coal reserves is not a static number, but can change over time, as more exploration is carried out, technologies advance and prices evolve. Coal reserves are also widely distributed, with all continents having significant deposits of the fuel, meaning that, typically, coal is not subject to energy security concerns due to geopolitical tensions. The world's coal resources, that is, deposits that are not necessarily exploitable at current prices or with current technology, are more than 20-times larger than reserves (Table 5.3).

Table 5.3 ▷ Remaining recoverable coal resources, end-2015 (billion tonnes)

	Coking coal	Steam coal	Lignite	Total resources*	Share of world	Proven reserves	Share of world	R/P ratio**
North America	1 034	5 838	1 519	8 390	36%	259	25%	345
Central & South America	3	32	25	61	0%	14	1%	141
Europe	187	387	402	976	4%	133	13%	223
Africa	35	262	0	297	1%	13	1%	50
Middle East	19	23	-	41	0%	1	0%	981
Eurasia	731	2 191	1 380	4 302	19%	189	18%	405
Asia Pacific	1 507	6 026	1 413	8 946	39%	419	41%	83
World***	**3 516**	**14 758**	**4 739**	**23 013**	**100%**	**1 029**	**100%**	**143**

* The breakdown of coal resources by type is an IEA estimate and proven reserves are a subset of resources. ** The reserves to production ratio (R/P) represents the length of time that current proven reserves would last if production was to continue at current rates. *** Excludes Antarctica.

Sources: IEA analysis; BGR (2016).

Production

Global coal production reaches just over 5 600 Mtce in 2040, up from 5 270 Mtce in 2016 (Table 5.4). Outside China, most coal is produced in surface mines, but the depth of China's coal reserves means that 90% of extraction there requires underground mining. As a result, nearly two-thirds of the global coal production comes from underground operations.

Coal mining is generally a labour intensive business, and we estimate that around 5 million people were directly employed by the coal industry worldwide in 2016. In the New Policies Scenario, productivity improvements especially in China and India bring this figure down to around 1.5 million in 2040. Job losses on this scale – whether due to mechanisation, restructuring or loss of competitiveness – are bound to be politically sensitive, especially given the tendency for entire communities to be dependent coal on mining. The contraction of coal mining in western Europe in recent decades has shown that it is challenging to manage job losses while avoiding social hardship and preparing coal mining communities for a new economic future without coal. Other parts of the world, including China, eastern Europe and the Appalachian region in the United States are likely to face similar challenges over the *Outlook* period as their coal industries improve productivity or close mines for want of profitability.

Table 5.4 ▷ Coal production by region in the New Policies Scenario (Mtce)

	2000	2016	2025	2030	2035	2040	2016-2040	
							Change	CAAGR
North America	824	566	537	514	499	489	-77	-0.6%
United States	767	509	499	482	469	459	-50	-0.4%
Central & South America	48	91	91	91	91	95	4	0.2%
Colombia	36	84	84	84	84	88	3	0.2%
Europe	396	242	187	151	117	106	-136	-3.4%
European Union	307	177	122	87	59	49	-129	-5.3%
Africa	187	216	234	238	246	276	60	1.0%
South Africa	181	205	210	204	198	200	-6	-0.1%
Middle East	1	1	1	1	0	0	-1	-4.8%
Eurasia	234	362	367	371	371	378	15	0.2%
Russia	184	294	290	292	289	294	1	0.0%
Asia Pacific	1 564	3 793	4 072	4 199	4 259	4 269	477	0.5%
Australia	235	416	421	438	443	473	57	0.5%
China	1 019	2 516	2 592	2 575	2 504	2 367	-149	-0.3%
India	187	403	610	752	885	994	591	3.8%
Indonesia	65	349	341	321	309	316	-33	-0.4%
World	**3 254**	**5 271**	**5 488**	**5 566**	**5 584**	**5 613**	**342**	**0.3%**

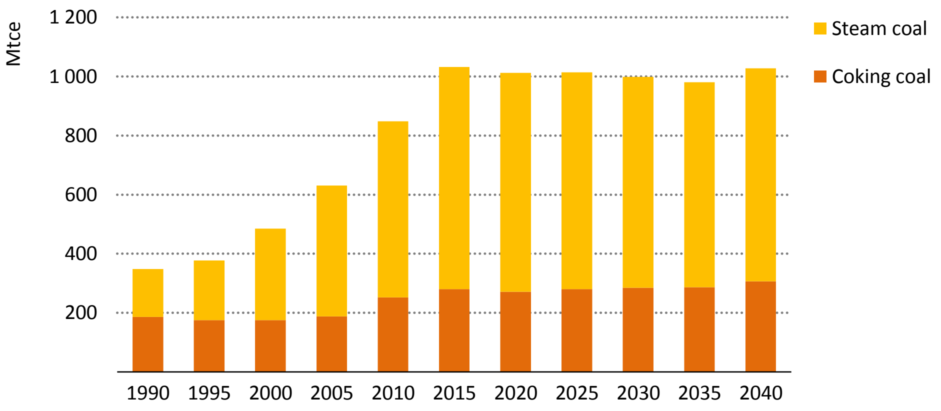
Note: Historical data for the world can differ from demand in Table 5.2, due to stock changes.

China remains the world's largest coal producer throughout the projection period while India, currently the fourth-largest producer (but third-largest in terms of mass, as Indian coal typically has high ash content) overtakes the United States (and Australia) in the early 2020s to become the second-largest coal producer. The share of steam coal increases from around three-quarters now to over 80% in 2040, as coking coal production declines from 967 Mtce in 2016 to 805 Mtce in 2040 (and lignite production drops from 255 Mtce to 230 Mtce). The drop in coking coal production is mostly due to China moving away from the basic-oxygen furnace in steel production. Export-oriented coal producers like Australia, Russia or Mozambique manage to expand their coking coal production over the next 25 years, primarily targeting rapidly growing steel producers like India.

Trade[5]

In the past 25 years, coal trade has more than tripled. It fell by 4% in 2015, but is estimated to have rebounded slightly in 2016. In the New Policies Scenario coal trade does not grow, with trade volumes in 2040 still below 2015 levels (Figure 5.4). In overall terms, the age of rapid expansion in coal trade is over. However, the global trend masks stark regional variations and some differences between types of coal.

Figure 5.4 ▷ Global trade by coal type in the New Policies Scenario



Global coal trade stays broadly flat over the projection period

Over the *Outlook* period, coal imports decline in advanced economies like the European Union, Japan and Korea. They also decline in China, which in 2016 was the biggest coal importer in the world. Imports continue to play an important balancing role during China's coal industry restructuring process, but this process is assumed to be largely accomplished

5. Unless otherwise stated, trade figures in this chapter reflect volumes traded between the countries/regions modelled in the *WEO*, and therefore do not include intra-regional trade.

by the mid-2020, and China's need for coal imports therefore declines. By 2040, Chinese coal imports have dropped to 70 Mtce, down from nearly 200 Mtce in 2016 (Table 5.5).

The declines are offset by increases in other parts of the world, notably South and Southeast Asia. In India, imports, currently in decline, are expected to pick up again from the early 2020s and increase through to 2040. India thus regains its position as the world's largest importer, with procurements from the international market reaching over 235 Mtce in 2040 – a 45% increase over 2016 import levels (see section 5.3.3). Similarly, fast growing and price sensitive economies like Viet Nam, Philippines, Malaysia, Thailand and Pakistan increasingly turn to the international coal market to meet their energy needs.

Table 5.5 ▷ Coal trade by region in the New Policies Scenario

	2016		2025		2040		2016-2040
	Trade (Mtce)	Share of demand*	Trade (Mtce)	Share of demand*	Trade (Mtce)	Share of demand*	Change (Mtce)
North America	56	10%	56	10%	49	10%	-6
United States	44	9%	37	7%	33	7%	-12
Central & South America	41	45%	38	42%	35	37%	-7
Colombia	79	93%	77	92%	78	89%	-1
Europe	-206	44%	-196	51%	-138	57%	-68
European Union	-149	44%	-148	55%	-86	64%	-63
Africa	66	31%	74	32%	74	27%	8
South Africa	72	35%	80	38%	87	43%	14
Middle East	-3	69%	-7	90%	-9	96%	6
Eurasia	148	41%	146	40%	158	42%	10
Russia	134	46%	135	47%	152	52%	18
Asia Pacific	-82	2%	-112	3%	-170	4%	87
Australia	360	86%	364	87%	427	90%	67
China	-196	7%	-134	5%	-70	3%	-126
India	-163	28%	-191	24%	-235	19%	72
Indonesia	292	84%	249	73%	163	52%	-129
Japan	-168	100%	-149	100%	-116	100%	-52
World**	**1046**	**20%**	**1004**	**18%**	**1009**	**18%**	**-38**

* Production in net-exporting regions. ** Total net exports for all *WEO* regions, not including intra-regional trade.

Note: Positive numbers denote net exports and negative numbers denote net imports of coking and steam coal.

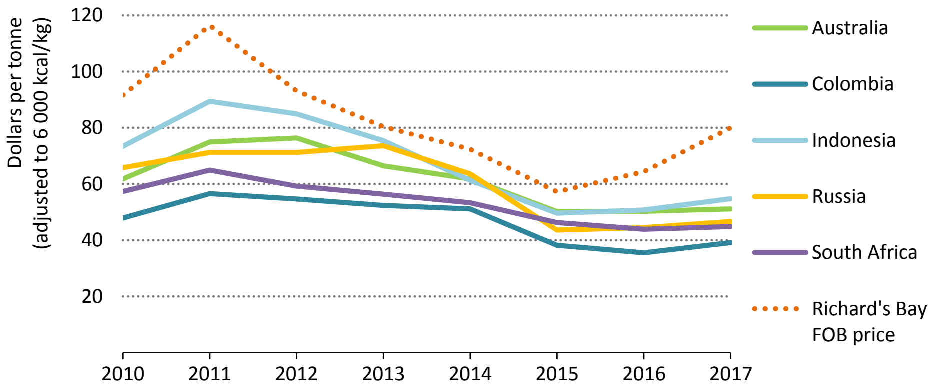
Steam coal has dominated the expansion of coal trading over the past 25 years and now accounts for more than 70% of trade. This pattern changes over the *Outlook* period, with coking coal trade growing by 0.2% per year while steam coal trade declines. Coking coal is scarcer than steam coal, and even countries like India that are endowed with considerable overall coal reserves may not be self-sufficient in terms of domestic coking coal production. Heavy industries like steel and cement are particularly important in developing countries, and they underpin growth in coking coal trade.

Costs and investment

Unless new infrastructure such as a railway line or port needs to be built to develop a new coal field, capital expenditure in coal mining is relatively modest. The costs of coal production tend to be dominated by its variable components, on-site labour and mining materials such as fuel, explosives and spare parts. The variable costs of production, sometimes termed cash costs, are thus central to the economic viability of a mining operation. If prices fall below the variable costs of a mine, then a mine is likely to be temporarily or permanently shut, unless there is an expectation that this is a very temporary state of affairs.

5

Figure 5.5 ▷ Average FOB cash costs for global seaborne steam coal trade and Richard's Bay FOB coal price



The export-oriented coal industry has achieved marked cost cuts in the past few years

Note: FOB = free on board.

Sources: CRU Thermal Coal Cost Model (2017); IEA analysis.

Coal prices dropped steeply between 2012 and 2016. Since 2012, all major steam coal exporters have managed to achieve substantial cost reductions in response. Marginal costs – the costs of the last mine needed to satisfy demand – are a good indicator for price formation (see the *WEO-2016* for a detailed discussion), but what happens at the margin is typically not representative of the cost position in the industry. Average costs are a better indicator as to how the industry has managed to cut costs during the period of falling coal prices. Cost cuts were achieved principally through mine closures, workforce reduction, cost discipline, high-grading (that is focussing on the most productive parts of a coal deposit), and deferral of capital expenditure. In some countries, marked contributions also came from a favourable exchange rate evolution (see the *WEO-2016*). The cuts were deepest in the countries that have a high-cost base such as Australia, Indonesia and Russia (Figure 5.5). South Africa and Colombia, with most of their operations at the lower end of the cost curve, felt less pressure to bring costs down.

Although average costs cannot explain price levels, a comparison of the two shows that the Richard's Bay FOB coal price (the price that South African exporters receive) came dangerously close to the average costs of a number of producers between 2013 and 2015. While this coal price may not reflect what other producers received in terms of price, it still suggests that a number of operations around the world were running at a loss in this period.

Coal prices have been moving upwards since early 2016, raising the profitability of the coal industry. Although export-oriented coal industries have been working hard to bring down their cost base and reduce overcapacity, their efforts played a limited role in this recent rise in prices. With global demand estimated to have declined over the course of 2016, what bumped prices up on the international market was an (unexpected) increase in Chinese imports following the introduction of measures to control domestic production in early 2016. Current price levels should thus not be misinterpreted as a true signal of scarcity. Many new mining projects may now look attractive again, but our projections suggest that Chinese imports will decline again after a period of volatility over the next few years (see Chapter 14). Many mines that have been idled in Indonesia and elsewhere could make a gradual comeback without much capital expenditure. Investment activity however is projected to pick up from the mid-2020s when many of the mines that were built during a period of rapidly rising coal demand, in the early 2000s, near depletion (the average lifetime of a mine is around 25 years).

In the New Policies Scenario, cumulative investments of some $1 trillion are needed in the global coal supply chain in the period to 2040. More than three-quarters of the spending is for mining, with the remainder for infrastructure. To keep an existing mine operational, substantial capital needs to be spent over its lifetime on maintenance and replacement of machinery and equipment. Such spending accounts for half of the mining investment over the period.

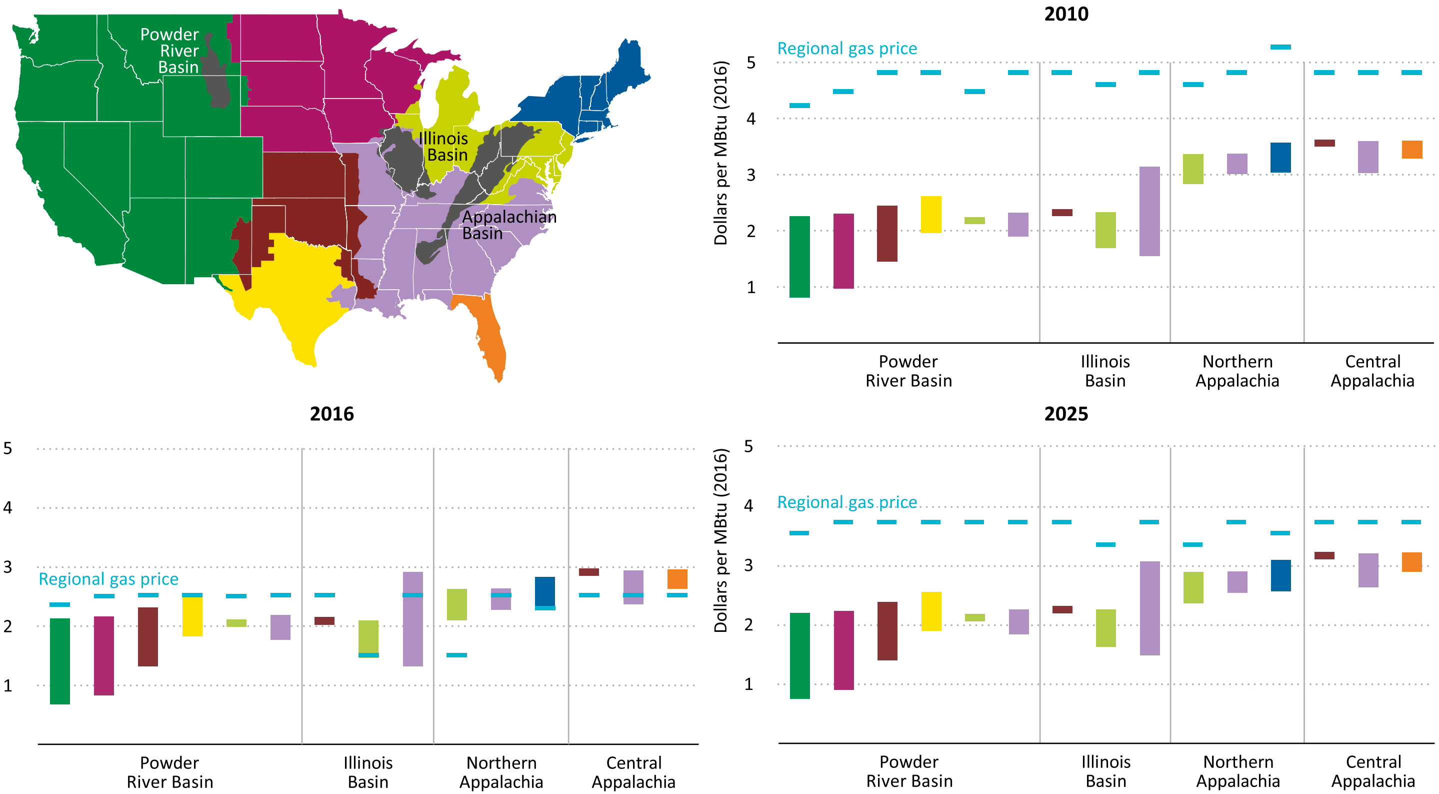
5.3.3 Regional insights[6]

United States

The US coal market is undergoing a period of rebalancing, reorganisation and consolidation, and provides a good example of such a process happening in a market-based way. In 2016, there was a period when companies accounting for around half of the country's coal production were under bankruptcy protection. Capital was written off, jobs were lost, assets were closed and costs were cut. This caused much hardship in communities that depend heavily on coal mining, but the country's major coal producers are now better prepared for a tough and uncertain future.

6. Please refer to Chapter 14 for regional insights on China's coal market.

Figure 5.6 ▷ **Delivered cost of coal and natural gas to different power systems in the United States**



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Even without taking into account the typically higher efficiency of gas-fired plants, gas has outcompeted coal in the eastern US in 2016. With gas prices rising in the long term, the position of coal improves, but efficiencies remain critical for the dispatch order of coal and gas.

Coal production is estimated to have fallen by 17% to around 510 Mtce in 2016, the second year of decline in a row. Environmental policies have played a role in this decline: for instance, the introduction of the Mercury and Air Toxics Standard has pushed many older coal plants into retirement. But the primary reason for declining production is the ample availability of inexpensive natural gas. In 2016, for the first time, more electricity was generated from gas than from coal, but the competitive picture is not uniform across the country: coal-to-gas competition has a strong geographic component and needs to be assessed on a regional level (Figure 5.6). The western United States, where low-cost coal (mostly from the Powder River Basin) prevails, sees limited exposure to gas competition. In the eastern United States – the location of the Marcellus play, the biggest shale deposit in the United States, and mostly served by higher cost coal from the Appalachian basins or by coal transported over long distances – the situation is different, and coal faces strong competition from gas. The outlook for the various basins thus differs. The Powder River Basin and to a degree also the Illinois Basin primarily struggle with coal plant retirements over the coming 25 years, while the Appalachian basins bear the brunt of lower coal demand due to fuel switching.

Coal consumption in the United States drops to 460 Mtce in 2040, some 10% below today's levels. The figure of 460 Mtce in 2040 is 70 Mtce higher than in the *WEO-2016*. There have been two major revisions since last year: on the one hand, the New Policies Scenario no longer includes the Clean Power Plan, which as a result raises coal demand. On the other hand, an upward revision in shale gas resources translates into a lower natural gas price in the United States, which reduces coal demand. Coal-fired power plant capacity falls from 287 GW in 2016 to around 210 GW in 2040 – no new coal plants are built in the United States, although there are a few lifetime extensions (see Chapter 6).

Coal industry employment dropped below 50 000 in 2016, and our projections suggest that this could fall to less than 35 000 by 2040. These job losses would be concentrated in the eastern United States (West Virginia, Kentucky and Pennsylvania), where operations are often small and relatively high cost. Exports provide limited relief: Europe, the traditional market for coal from the eastern United States, continues to import less coal, while other suppliers to Europe, especially Colombia, have a more favourable cost base. As a result, US net coal exports drop from just under 45 Mtce in 2016 to around 30 Mtce in 2040.

India

India is the hope of many coal-exporting companies around the world. However, the fundamentals for coal demand growth there are less strong than just a few years ago, and it cannot be taken for granted that rising demand will lead to increasing imports.

Our *Outlook* projects coal demand expanding to just under 1 230 Mtce in 2040, up from 575 Mtce in 2016 (rising at an average rate of 3.2% per year). The primary driver is economic growth, which brings increases in living standards, infrastructure investment and urbanisation. As a result, production of steel more than quadruples by 2040, that of cement triples, and electricity generation more than triples.

The utilisation of coal-fired power plants has been dropping over the past years, and that has raised doubts over whether India actually still needs new coal plants once those that are under construction are completed. In the New Policies Scenario, coal remains a key pillar of the power system in India. We project the commissioning of 370 GW of new coal-fired capacity over the *Outlook* period (of which 50 GW are currently under construction). However, this projection is subject to many uncertainties. Two are particularly important. The first concerns the rate of economic growth. Our scenarios assume GDP in India to grow at a rate of 6.5% per year through 2040: a lower rate of growth would depress electricity demand and consequently the call on coal-fired plant, whereas a higher rate of growth would increase them. The second concerns the rate at which the cost of alternative technologies comes down. The Indian government has made solar PV an energy policy priority and, with rising deployment levels, costs have fallen at an impressive speed (see Box 5.1). Over the year 2016, installed PV capacity in India increased by nearly 80% to 9 GW. India has set itself an ambitious target of reaching 100 GW of solar PV by 2022: this looks hard to achieve, but a faster-than-expected drop in costs would result in significant upside potential for solar PV and downside for coal.

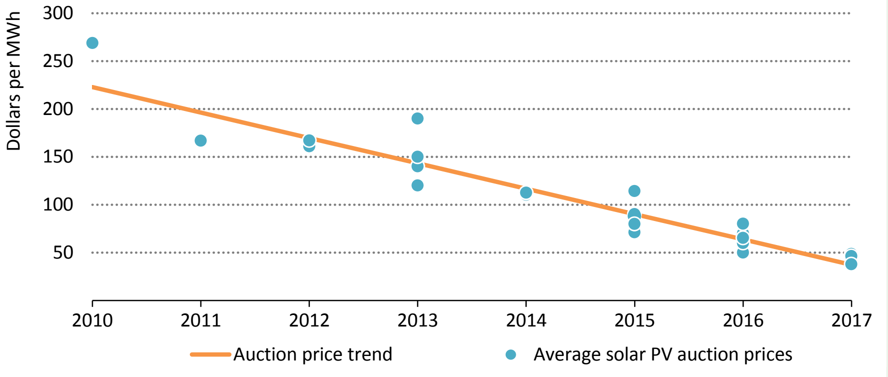
While coal production increases in India may have fallen short of annual production growth targets, it saw increases of 8% in 2014, 4% in 2015 and another 7% increase is estimated to have taken place in 2016. India's coal production is projected to increase further from around 400 Mtce in 2016 to almost 1 000 Mtce in 2040. The coal shortage experienced a few years ago has passed, although inefficient allocation mechanisms mean that some plants still run short of coal at times while pit-head stocks rise at the mines. When there were domestic coal shortages, coal consumers in India far from the coast had to rely on expensive coal imports to meet their needs, but that economic inefficiency is now gradually disappearing, and Indian coal imports fell in 2016 for the second consecutive year. Over the next ten years, steam coal imports remain largely flat while imports of coking coal increase markedly. By 2040, coal imports are projected to increase from 163 Mtce in 2016 to 235 Mtce, with three-quarters of the increase in imports coming from coking coal.

The likelihood of an increase in imports of coking coal is relatively uncontroversial in India, given limited domestic coking coal reserves. However, the projection of rising steam coal imports from the late 2020s is subject to considerable policy uncertainty. The underlying logic behind our projection is that market-based competition for coal could see India's west coast emerging as a new arbitrage point and price marker for global trade, in a way that is similar to China's coastline today. For the moment, imports appear to be the cheapest supply option along most of India's western coastline. However, it cannot be taken for granted that domestic coal would be at a disadvantage: the coal tax reform proposed in May 2017 seems likely to improve the position of domestic coal, and so does a new allocation system for coal that would facilitate the purchase of domestic coal for those buyers that do not have a formal supply contract with Coal India Limited. The possibility of a strengthened future policy commitment to renewables, or indeed to natural gas, also raises questions about India's future coal demand and, in turn, its import requirements. A reversal in the projected trend of rising imports is possible if circumstances change: this would have significant repercussions for coal exporters around the world.

Box 5.1 ▻ Coal's number one competitor in India: the sun

Already in early 2016, India's former Minister for Power, Coal, New and Renewable Energy said that "I think a new coal plant would give you costlier power than a solar plant". Indeed, auction prices for large-scale PV installations have dropped rapidly over the past few years. In 2010, the auction price for a PV tender exceeded $250 per megawatt-hour (MWh), more than five-times what an average coal plant received for a MWh at that time (Figure 5.7). Seven years later, auction prices have gone as low as $40/MWh (tender for the 750 megawatt Bhadla Solar Park). A combination of factors explains the sharp drop in PV cost, among them a reduction in module prices, fierce competition between developers, a fall in the cost of financing, and the strengthening of the Indian rupee in currency markets.

Figure 5.7 ▻ Auction results for solar PV in India



Solar PV auction prices are falling fast in India, narrowing the cost gap with other technologies

As discussed in the special focus on renewables in the *WEO-2016*, auction prices may not reflect the full underlying costs of the projects, and there is uncertainty over whether the achieved auction prices are actually profitable for the developers. It is also worth remembering that the PV auctions in 2017 are for delivery a few years later, so do not necessarily reflect prevailing costs (developers may have built in an assumption about future cost reductions into their bid). But developers clearly believe in India's solar potential, and are keen to gain a foothold in what is set to be a huge market for the solar industry. Moreover, the cost gap between PV and coal-fired electricity is closing fast and, while coal-fired generation is a mature technology that is unlikely to become significantly cheaper, the future is likely to see further reductions in PV costs. Solar PV could therefore disrupt the future of coal in a country that has been widely expected to be a major growth engine for global coal use for decades to come.

Major exporters

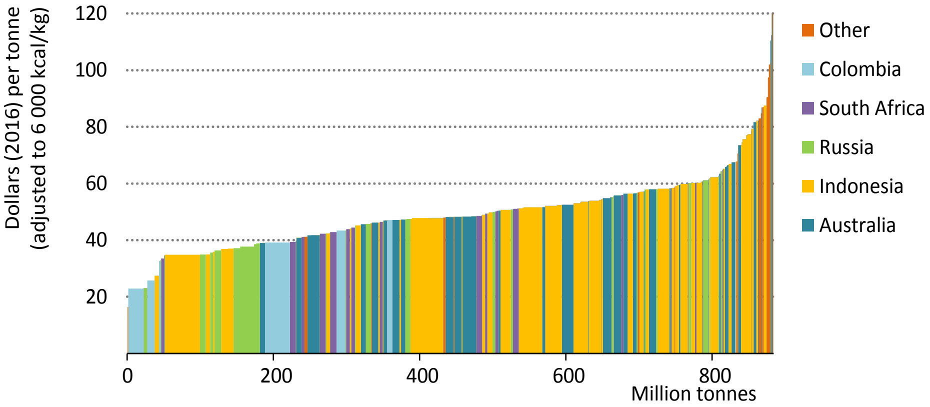
Australia, the world's largest coal exporter with shipments of 360 Mtce in 2016, has two primary competitive advantages: the presence of a world-class mining industry in a regulatory environment that is generally conducive to the extractive industries, and the availability of high quality coal reserves at shallow depth (a lot of which is coking coal). Coal companies in Australia have navigated the industry crisis better than many of their peers elsewhere, rigorously cutting costs and improving productivity. Australian coal exports remained flat in 2016, but they are projected to rise over the *Outlook* period to around 425 Mtce in 2040. The share of coking coal in Australian exports stays at around half, and the rise in exports means that Australia increases its market share of the international coking trade to over two-thirds in 2040. The recent merger and acquisition wave has increased supplier concentration in the coking coal business, an evolution that is closely eyed by steel producers around the world.

The Galilee Basin, a huge untapped coal deposit in Queensland, is targeted by various companies as the next frontier for Australian steam coal exports. Various projects are in the pipeline: the most advanced is Adani's Carmichael project, which encompasses the development of a mine and an associated railway to the port of Abbot Point. These projects have spurred much controversy on environmental and economic grounds. Our New Policies Scenario is consistent with some development happening in the Galilee Basin, but the commercial viability of the projects is closely tied to the trajectory for coal imports in India and production in Indonesia, which is subject to significant uncertainties in both countries (see sections on India and Indonesia).

Indonesia has a diverse coal industry. There are some large companies with access to low-cost coal deposits which achieve considerable economies of scale and produce some of the least-cost coal available to the international market (Figure 5.8). However, many operations are small and have higher costs: during times of high prices they tend to increase output and exports rapidly. Together with a high share of costs incurred in US dollars, which has prevented Indonesian companies benefiting from the general appreciation of the dollar (see Chapter 5 of the *WEO-2016*), this has pushed many mines to the high-cost end of the seaborne supply cost curve. We estimate that, after two years of decline, Indonesia managed to slightly expand its exports in 2016, but they remain significantly below the 342 Mtce reached in 2013. The Indonesian government has announced plans to cap coal production at 400 million tonnes (broadly equivalent to 300 Mtce) from 2019 onwards, and to prioritise supply to the domestic market. This informs our long-term production outlook, although the fragmented nature of the Indonesian coal industry (it has many small mines that are difficult to control) and the importance of coal mining for employment and fiscal revenues together mean that meeting the target will be very challenging.

The New Policies Scenario sees Indonesian coal production dropping to 340 Mtce in 2025 and to 315 Mtce in 2040. With domestic demand growing strongly, exports drop faster, from over 290 Mtce in 2016 to less than 250 Mtce in 2025 and further to around 165 Mtce in 2040. For the Indonesian coal industry, the *Outlook* period is thus characterised by a decisive shift in focus away from export towards the domestic market. This creates space for other exporters to take market share from Indonesia in a market with otherwise limited growth potential. The actual Indonesian export trajectory however is subject to considerable uncertainties concerning the pace at which domestic consumption grows and the willingness of Indonesian policy-makers to stick to a hard production cap during periods of higher coal prices. Indonesia may well keep its newly acquired role of swing supplier in the Asia-Pacific market and temporarily ramp up production to benefit from price volatility. It remains relatively easy in Indonesia to open new coal mines, bring idled coal mines back online and ramp up production at existing facilities.

Figure 5.8 ▷ FOB cash costs for global seaborne steam coal trade



Many Indonesian mines are high cost and can adjust their output to price signals, turning the country into a swing supplier in the Asia-Pacific region

Sources: CRU Thermal Coal Cost Model (2017); IEA analysis.

Russia is currently a very competitive coal exporter on the international market and has managed to expand its shipments continuously over the past few years. Our estimates for 2016 exports point to a 10% increase over the 120 Mtce achieved in 2015. Direct mining costs in Russia are among the lowest in the world, but what tips the balance in terms of competiveness on the international market are the railway tariffs for inland transport distances that can easily reach 6 000 kilometres. The recent devaluation of the rouble has significantly reduced this transport cost component and helped to shift many Russian mines to the low-cost end of the supply curve. Based on our assumption of constant exchange rates, Russian coal remains relatively low cost in the long run, but the country's export prospects are held back by declining import needs in some of its traditional markets like the European Union, Japan and Korea. To benefit from growth in South and Southeast Asia, the Russian mining industry moves further east where plenty of untapped coal deposits are located. A few projects are already under development like the Elga and the Amaam projects. Overall, Russian exports are projected to increase by 13%, topping 150 Mtce in 2040.

Colombia provides some of the least-cost coal to the international market, and is estimated to have increased exports in 2016 by 7% over the level of 74 Mtce in 2015. The main difficulty Colombia's coal industry faces in the longer term is that it is far away from the few growth centres in global coal trade. Today, Colombian coal exporters ship some 65% of their product to Europe, but this market is in decline. North Africa and Turkey continue to offer some export potential, but not enough to offset the declines elsewhere, especially in northwest Europe. Supported by low freight rates, Colombian exporters have occasionally managed to place tonnage in India and other parts of Asia in the past few years. We project Colombian exports to stay largely flat at 80 Mtce through 2040, a result in part of the high sensitivity of Colombian competitiveness to ocean freight rates, which are projected to gradually increase over time.

South Africa is well placed both to serve the mature markets in the Atlantic basin and to benefit from import growth in the Indian Ocean, but its coal industry nevertheless faces a number of challenges in the coming decades. Domestic coal demand has peaked and the fuel is being gradually pushed out of power generation by rapidly expanding renewables. By 2040, the *Outlook* sees coal demand falling to less than 115 Mtce, down from 135 Mtce in 2016. Coal mining in the Mpumalanga province is mature and many mines are nearing depletion. To increase production, mining activity in the remote Waterberg basin would have to be expanded. Further development of the Waterberg would primarily target domestic demand but also would have positive spill-overs for exports. Our analysis suggests that South African exports increase from 72 Mtce in 2016 to around 85 Mtce in 2040 while production drops slightly (to below 200 Mtce in 2040). However, renewables and natural gas are increasingly gaining traction with the government. Upside for either of the two would translate into further downside for coal and possibly delay development of the Waterberg, which would constrain the availability of coal for exports.

Mozambique is set to play an increasingly important role in global coking coal trade. The 18 Mtpa Nacala corridor has eased the bottlenecks in the country's coal supply chain and played a crucial role in enabling economies of scale to bring costs down. With a number of other infrastructure projects in the pipeline, we project an increase in Mozambican coal exports from 6 Mtce in 2016 to 30 Mtce in 2040.

Mongolia has plenty of high quality coking coal, but the country's landlocked geography ties the Mongolian coal industry's future entirely to the fortunes of the market in China. Mongolia achieved a record 25 Mtce exports to China in 2016, but we anticipate Mongolian exports declining over the projection period to less than 15 Mtce.

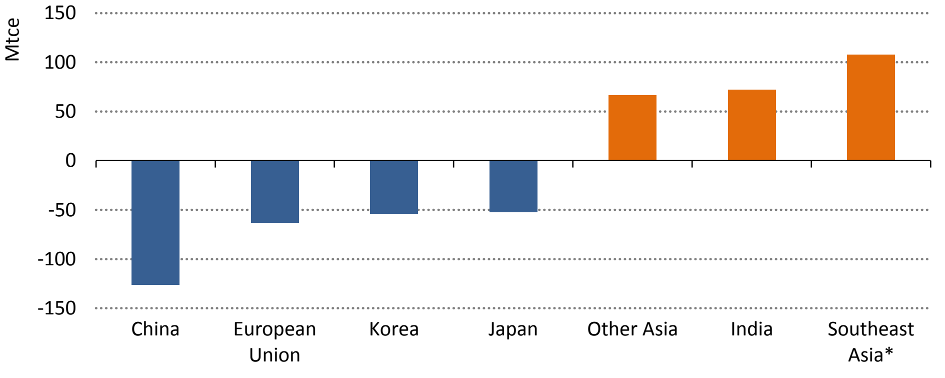
Canada is a significant exporter of coal (mostly coking coal) with net shipments of around 20 Mtce in 2016. We expect exports to broadly stay at this level over the *Outlook* period.

Major importers

The **European Union** (EU) has targets to cut greenhouse-gas emissions by 40% by 2030 (compared to 1990) and to expand renewables to 27% of total final energy consumption.

These have clear negative implications for coal, and various EU countries already have plans in place to close all their coal-fired power plants over the coming decades, including France (by 2023), the United Kingdom (by 2025) and Finland (by 2030). As a result, coal demand in the European Union drops by over 60% in the next 25 years to 135 Mtce in 2040 – a bigger drop than in any other region. Domestic coal production falls even faster, reaching less than 50 Mtce in 2040, down from around 175 Mtce in 2016. The combination of the two trends results in a fall in imports from 150 Mtce in 2016 to 85 Mtce by 2040 (Figure 5.9).

Figure 5.9 ▷ Change in net coal imports by key region in the New Policies Scenario, 2016-2040



There are stark regional contrasts in the way coal imports change between 2016 and 2040

*Southeast Asia excludes Indonesia.

Japan's imports are estimated to have stayed flat at just under 170 Mtce in 2016. Its imports are projected to drop by 30% over the period to just over 115 Mtce in 2040, reflecting 60% growth in electricity generation from renewables by 2040, together with energy efficiency improvements and the restart of some nuclear power plants. The primary uncertainty for this import trend is the speed at which nuclear power plants are allowed to restart.

Korea's coal imports are estimated to have stayed flat in 2016 at around 115 Mtce. Korea's new government has stated its willingness to reduce the country's reliance on coal, and has outlined a set of measures designed to curb coal use. Among them are the closure of ten old coal plants, a moratorium on new coal plants, a set of environmental criteria for plant dispatch and an increase in coal taxes. As a start, the government ordered a temporary shutdown of eight old coal plants for one month during June 2017. At the same time Korean policy-makers envisage a strong push for renewables and natural gas. Against this backdrop, we see Korean coal imports dropping by nearly 50% to less than 60 Mtce in 2040.

Southeast Asia, together with India and other developing economies in Asia, is the primary growth centre of coal demand in the world.[7] The region's coal consumption grows two-and-a-half times to around 385 Mtce in 2040. Coal demand growth in Southeast Asia is clearly a power generation story: power plants account for three-quarters of the additional coal use in the coming 25 years. Electricity demand grows by 3.7% per year over the period and the region's power system planners need to mobilise all sources of power generation to keep pace. Coal is a fuel of choice not only because it is markedly cheaper than natural gas in the long term but also because coal projects are in many cases easier to pursue as they do not require capital-intensive fuel delivery infrastructure (unlike gas). However, some major planned coal projects face considerable public opposition, including the Krabi plant in Thailand, the Inn Din plant in Myanmar and the Atimonan plant in Philippines, which has delayed development of some new capacity. The share of coal in the region's power mix increases from 35% today to 40% in 2040 while that of gas drops from nearly 45% to less than 30%. The region as a whole is a net exporter of coal, but net exports dwindle over the *Outlook* period as Indonesian coal exports decline and other economies' coal imports increase.

7. For a more detailed analysis, please refer to *Southeast Asia Energy Outlook*: *World Energy Outlook Special Report* (IEA, 2017b) available at *www.iea.org/southeastasia*.

Power markets and electrification

Empowering the world

Highlights

- Electricity demand rises by 60% to 2040 in the New Policies Scenario, with over 85% of global growth occurring in developing economies. Motor systems, appliances, cooling, and information and communication technologies (ICT) make up almost 75% of the global increase in electricity demand. Energy efficiency and structural change see the link between economic growth and electricity demand weaken globally, despite greater electrification of heat and transport.
- The past year has seen significant policy changes in the power sector in major economies, especially a shift away from coal towards renewables. On this new course, global gas-fired capacity overtakes coal by 2030 and solar PV surpasses wind by 2025 and hydropower by 2040. While nuclear development is confined to a small number of countries, renewables expand everywhere. Coal capacity continues to grow, but at a much slower pace than in the past and increasingly concentrated in Asia.
- Global growth in electricity supply to 2040 is mainly from wind and gas (23% each) and solar PV (20%). The share of fossil fuels in generation falls from two-thirds today to half by 2040, while renewables rise from 24% to 40%. Nuclear's share is steady at about 10% and China is the global leader by 2030. In the European Union, wind becomes the leading source of electricity soon after 2030. In the United States, low gas prices help the fuel maintain its leading role. In India, coal's share drops from 76% today to half by 2040, as solar PV rises by 100-fold and wind by nine-fold.
- The trend in global use of fossil fuels in the power sector largely decouples from the trend in electricity demand, as a result of the rise of renewables and power plant efficiency gains. For example, gas-fired electricity generation increases by close to 60% from 2016 to 2040, while related gas use rises by less than 40%, due to greater reliance on highly efficient plants.
- Total investment in the power sector to 2040 is $19.3 trillion, almost half of total energy supply investment. Renewables capture two-thirds of the investment in power plants. Subsidies for renewables in power were $140 billion in 2016, mainly through feed-in tariffs. Support mechanisms harnessing competitive forces, such as auctions, are set to become dominant, helping to lower the global average subsidy per unit of output for new solar PV by 70% by 2030 and those for wind by 40%.
- Global CO_2 emissions from the power sector rise by only 5% from 2016 to 2040, while meeting 60% higher electricity demand and 10% more heat demand. Declines are most pronounced in the European Union, United States, Japan and Korea. In China, CO_2 emissions peak around 2030. Emissions of all primary pollutants are reduced through fuel switching, efficiency gains and end-of-pipe control technologies.

6.1 Recent market developments

Electricity is an essential energy carrier for modern economies, providing energy services for cooling, refrigeration, lighting and information technologies, among others. Between 1990 and 2016, global electricity demand doubled, while total primary energy demand increased by almost 60%. This trend is set to continue, as economic growth and rising incomes, notably in developing countries, will raise demand for electricity-based services, and the 1.1 billion people who currently lack electricity gain access. Today, the power sector is responsible for close to 60% of the world's coal use, 36% of natural gas use and nearly 40% of energy-related greenhouse-gas emissions. This position, combined with the suite of low-carbon power generation technologies that are available at low cost, especially renewables, puts the power sector at the heart of any climate change mitigation strategy.

Electricity demand, after growing rapidly through the early years of this century, has slowed notably in advanced economies since the recession of 2008-09, and, more recently, in developing economies, such as China. For example, in the United States, electricity demand has been broadly flat since the recession, while in the European Union it has fallen by around 3%. In China, the growth of electricity demand was only 4% per year from 2013 to 2016, compared with 11% from 2000 to 2013. There are now some strong indications that the rate of electricity demand growth is decoupling from the rate of economic growth in a number of regions. Still, electricity demand growth has been rapid in some countries. For instance, growth in India went from an already strong 6.8% per year (2000-13) to 7.4% per year since 2013, as the government vigorously pursued the goal of universal access to electricity (though about 240 million people still lack electricity access today).

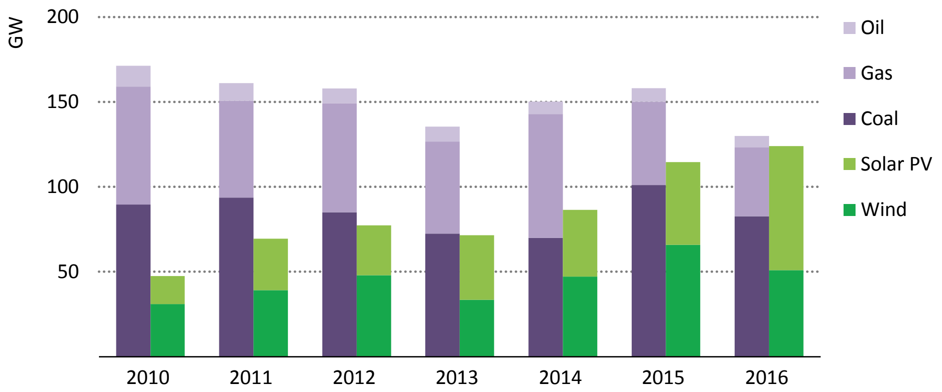
Low-carbon technologies in power generation continue to gain momentum, highlighted by the ratification in October 2016 of the Paris Agreement, committing the world to act together to mitigate climate change. Renewable energy technologies led the way in 2016, adding 165 gigawatts (GW) of power generation capacity worldwide, outpacing growth for all other sources combined.[1] Capacity additions of hydropower have slowed in recent years, falling more than one-quarter from a high-water mark in 2013, mainly due to a slowdown in China. This reduction was more than offset by the rapid growth of solar photovoltaics (PV) and wind power. Taken together, they added 126 GW of new capacity in 2016, just 4 GW short of equalling the combined total of new coal, gas and oil capacity (Figure 6.1). The global increase in solar PV of 74 GW in 2016 was almost one-quarter of total power generation capacity added in the year, and a 50% jump above the global deployment in 2015. China was the standout performer, with 34 GW of additions, a record level for any country by a wide margin, putting the 2020 minimum target of 110 GW well within reach. The dramatic change in the contribution expected from this technology is highlighted by the fact that a decade ago, China's official target for 2020 solar PV capacity was 1.8 GW. The United States also set a record with close to 15 GW of solar PV additions in 2016, double the previous year, while additions in Japan fell from 11 GW to 8 GW. India doubled the

1. Power generation capacity for all technologies is reported in gross terms.

deployment of solar PV in 2016, adding 4 GW, and is expected to almost double the rate of deployment again in 2017, based on strong policy support and declining technology costs.

Global wind power capacity additions were 52 GW in 2016, down about 20% from the high-water mark in 2015, but still the second-highest total ever deployed. Again China led the way, with wind power additions of about 20 GW: though lower than the 33 GW added in 2015, this still leaves China on track to meet the 2020 target of 210 GW. The change was largely due to announced cuts in future feed-in tariffs, highlighting the critical role of policy support in order to achieve stable growth. The European Union, notably Germany and France, continues to be among the global leaders in wind power, adding 13 GW in 2016. About 8 GW of wind power was added in the United States and 4 GW in India.

Figure 6.1 ▷ Global power generation capacity additions for fossil fuels, wind power and solar PV



Annual capacity additions of solar PV and wind power have been closing the gap with fossil fuels

Policy and market frameworks continue to play a critical role in the success of wind and solar PV, while the preferred method of support is changing. Auction schemes are gaining prominence and add to the momentum established by feed-in tariffs. Starting in developing countries, the trend has spread to more mature economies, including Japan and European Union (EU) countries such as Spain, so that almost 70 countries now use auction schemes. By fostering competition, auction schemes have been able to deliver some remarkably low guaranteed prices for the electricity delivered by renewables. Contracted prices for new solar PV projects continued to set new record lows over the last year, as low as $30 per megawatt-hour (MWh) in some regions, including in Mexico, United Arab Emirates and Chile, and below $40/MWh in India. Offshore wind also set records through auctions, with the first projects bid indicating no need for external support, sending a signal through the energy world (Box 6.3).

The nuclear power industry enjoyed successes and challenges in 2016. For a second year in a row, over 10 GW of new nuclear capacity came online, a level not seen since 1990. A further 60 reactors, with a combined capacity of 65 GW, were under construction at the start of 2017 and slated to become operational by the mid-2020s. Over one-third of these new builds were in China. In Japan, nuclear plants are slowly re-entering service, with 12 reactors now meeting post-Fukushima standards and five having re-started as of mid-2017. However, in 2016 just 3 GW of new construction was started, about half the average rate of the previous five years. In addition, the financial difficulties of the nuclear industry have cast a shadow over the industry and future growth prospects.

Globally, gas-fired capacity has expanded by 20% since 2010, this technology having been the preferred dispatchable option in advanced economies for the past decade. Combined-cycle gas turbine units accounted for almost three-quarters of all new gas-fired capacity deployed since 2000. This fleet of modern, flexible and high efficiency power plants, along with more being built, is set to change the balance and efficiency of fossil-fuel consumption in the power sector. A key factor behind this is the availability of cheap gas in a number of jurisdictions, most notably the United States, where gas prices remained very low in 2016. This situation helped gas-fired electricity generation exceed that from coal plants in the United States for the first time in 2016. The increasing availability of liquefied natural gas from multiple producers, with greater destination flexibility, brings energy security benefits and is set to reshape gas markets (see Chapter 9).

Recent developments affecting coal use have been mixed. Since 2000, 1 100 GW of coal-fired power plants have been built worldwide, 780 GW built in China alone. Gross coal capacity additions in 2016 amounted to 83 GW, more than any other technology. Plants built since 2000 represent over half of the total coal capacity in place today and they can be expected to operate through to 2040 and beyond. In addition, more than 210 GW of coal capacity is under construction, led by 90 GW in China (despite overcapacity concerns), almost 50 GW in India and close to 25 GW in Southeast Asia. On the other hand, retirements have accelerated in many countries, most notably in the United States, where 26 GW of coal-fired capacity has been closed in the last two years. In terms of recent trends in output the picture is still more mixed. Generation from coal experienced strong growth in the period 2000-13, driven by growth in developing Asia, notably China and India. However, between 2013 and 2016, total coal-fired generation declined, its share of global electricity supply falling from 41% to less than 38% (though coal remained the largest single source of electricity). In China, overcapacity and the surge of renewables capacity have meant declining utilisation of coal plants: the capacity factor dropped from 60% in 2011 to 49% in 2016. In the United States, coal-fired electricity generation in 2016 was nearly 40% below the peak set in 2005.

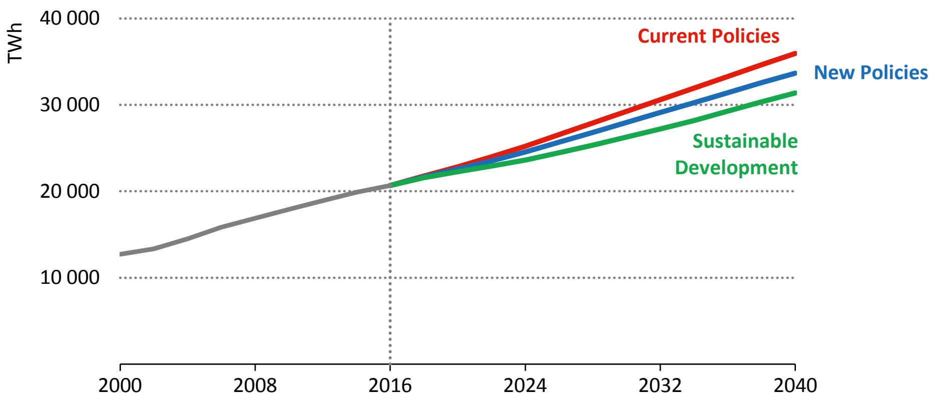
Energy storage – specifically lithium-ion batteries – and the digitalisation of the power sector represent two emerging market developments with the potential to change the nature of the sector. While energy storage has been an important part of many power systems for decades, in the form of potential energy in water reservoirs at hydropower facilities, interest in batteries is growing as their costs are declining. Batteries are increasingly being considered for applications at the utility scale (Box 6.2) and at the point of consumption. Batteries can provide a range of benefits, from helping to integrate variable renewables to deferring network investments, and can be built most anywhere in a matter of months. Batteries are one element of the digitalisation of the power sector, an emerging trend whereby digital sensors, data and analytics are being applied to power plants and network infrastructure. These tools present not only opportunities for efficiency gains and cost reductions within current market designs, but also the potential to reshape the design and operations of power systems through enhanced connectivity of both supply and demand (IEA, 2017a).

6.2 Electricity demand

6.2.1 Trends to 2040 by scenario

A further rise in electricity demand[2] is common to all *World Energy Outlook (WEO)* scenarios and, as electricity demand growth continues to outpace growth in final energy demand, the share of electricity in total energy use increases. Yet the differing policy inputs and assumptions that define the three *WEO* scenarios result in considerable divergence in electricity demand growth trajectories (Figure 6.2).

Figure 6.2 ▷ Evolution of electricity demand in the three *WEO* scenarios



Electricity demand continues to grow in each scenario, yet as a result of differences in policies and objectives, demand in 2040 varies considerably between scenarios

2. Electricity demand is defined as total gross electricity generated less own use in generation, plus net trade (imports less exports), less transmission and distribution losses.

The New Policies Scenario, the central scenario, reflects policies that are in place today, as well as an assessment of the implications of announced policy intentions and targets. In the New Policies Scenario, electricity demand reaches 34 470 terawatt-hours (TWh) in 2040, up from 21 375 TWh today. In each of the *WEO* scenarios, end-uses such as motor systems in industry, space cooling, large appliances, information and communication technologies (ICT), and small appliances are major contributors to rising demand for electricity. The share of electricity in final energy demand is set to rise from 18.7% today to 23.2% in 2040, due to structural change and electrification of new end-uses.

By 2040, electricity demand in the Current Policies Scenario (which assumes only policies currently in place) is nearly 37 000 TWh, 7% higher than in the New Policies Scenario, the difference is equivalent to nearly three-times the electricity demand of Russia today. Higher electricity demand in the Current Policies Scenario relative to the New Policies Scenario primarily reflects less ambitious energy efficiency policies in the buildings and industry sectors.

Far-reaching energy efficiency policies driven by decarbonisation ambitions see lower electricity demand growth in the Sustainable Development Scenario relative to the other scenarios, reaching 32 000 TWh in 2040. Demand in the Sustainable Development Scenario would be lower still were it not for the achievement of universal access to electricity, a central pillar of the scenario. This adds to electricity demand in 2040, but only to the extent of around 260 TWh more than in the New Policies Scenario. Additional electrification puts upward pressure on electricity demand in the Sustainable Development Scenario: electric vehicle (EV) uptake and electrification of other end-uses sees the share of electricity in final end-use rise to 26.5% in 2040, over three percentage points higher than in the New Policies Scenario. Transport electricity demand in the Sustainable Development Scenario is more than twice that in the New Policies Scenario, yet economy-wide electricity demand is more than 2 400 TWh lower (double the electricity demand of India today) primarily as a result of more intensive energy efficiency in end-uses.

6.2.2 Electrification: changing sources of growth

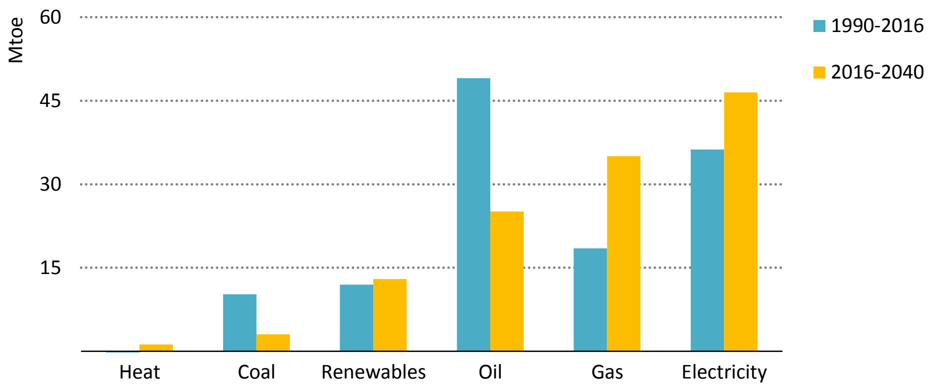
Electricity is becoming the energy of choice in most end-uses. Electrification is driven by many factors: accelerating adoption of EVs and heat pump proliferation see passenger vehicle and heating energy demand increasingly turn to electricity; the evolution of industrial production and processes requires more electricity,[3] millions of new middle-income families in developing countries add appliances and install cooling, and electricity progressively reaches those without access. Digitalisation can facilitate the electrification of energy demand.[4] In the New Policies Scenario, electricity demand

3. Examples of additional electricity demand include the transition to electric arc furnaces in the steel industry and the deployment of heat pumps to provide heat in industry (see Chapter 7.5.2).

4. For more information on the interaction between digitalisation and electricity demand, see *Digitalization & Energy* (IEA, 2017a).

growth is concentrated within certain end uses: 74% comes from industrial motors systems, space cooling, appliances and ICT. With total electricity demand growing at 2% per year from 2016 to 2040, nearly twice the rate of final energy demand, electricity experiences more growth than all fuels in the New Policies Scenario, meeting over 37% of additional final energy demand (Figure 6.3).

Figure 6.3 ▷ Annual average growth of final energy demand historically and in the New Policies Scenario



Electricity contributes the largest share to meeting additional energy demand and average growth in volume is more than in the past

Note: Energy demand by end-use fuel refers to the direct use of fuels at the end-use sector level, i.e. heat refers to heat supplied by district heating networks and oil refers to refined oil products.

Demand growth in advanced economies

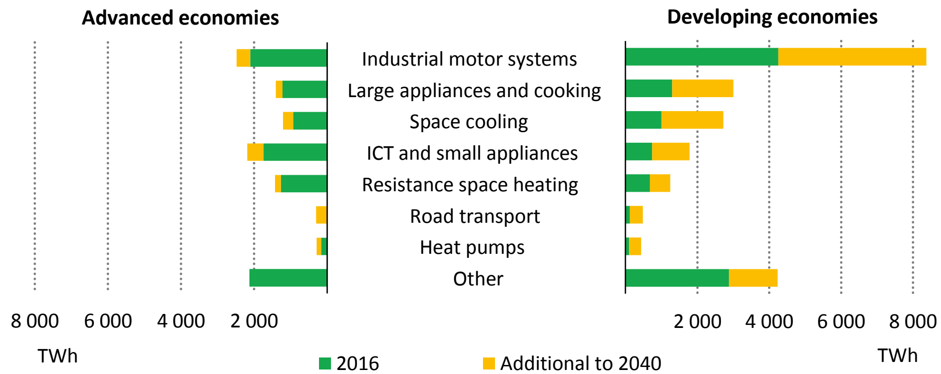
Electricity demand growth in the New Policies Scenario is dominated by developing economies, to the extent that advanced economies account for only 14% of additional demand to 2040. In advanced economies, overall electricity demand is expected to rise by only 0.7% per year, growth resuming after several years of stagnation. A growth rate of only around 0.2% in Japan and 0.4% in the European Union is projected (Table 6.1). The return of demand growth is principally due to additional demand for ICT and small appliances,[5] industrial motors, electric vehicles (EVs) and cooling.

The rapid penetration of devices such as smart phones and tablets has driven demand growth from ICT and small appliances, especially digital devices, in recent years and continues to do so through to 2040. In advanced economies, demand from ICT and small appliance loads has increased from around 600 TWh in 1990 to more than 1 700 TWh

5. ICT and small appliances include connected devices such as smart phones and tablets, computers, televisions and the data infrastructure supporting these loads, as well as other small appliances.

in 2016, doubling their share in total electricity demand to become the second-largest end-use (Figure 6.4). Electricity demand from ICT and small appliance loads is projected to continue to grow faster than total demand throughout the New Policies Scenario, reaching almost 2 200 TWh in 2040, more than double the total electricity demand of Japan today. Within transport, as EVs grow to represent 14% of the passenger car stock in advanced economies by 2040, their share in total electricity demand grows from less than 0.1% today to over 2% in 2040.

Figure 6.4 ▷ Electricity demand by end-use in the New Policies Scenario



Growth is centred in developing economies, driven by electric motors in industry, large appliances and cooling. In advanced economies, ICT and small appliances contribute to modest growth

Notes: Industrial motor systems refers to demand from motors and associated end-use devices in the industry sector. Heat pumps does not include those used for cooling. Large appliances include all refrigeration and cleaning appliances. Other includes loads from agriculture, desalination, other industrial loads, non-road transport and lighting.

In the cases of lighting, large appliances and heating, increases in demand for energy services are substantially offset by energy efficiency improvements, limiting electricity demand growth. For large appliances (e.g. washing machines, refrigerators, dishwashers), as ownership levels approach saturation point in advanced economies, continuing improvement in energy efficiency sees demand fall in the New Policies Scenario in Japan and major European economies. Meanwhile, the ongoing replacement of incandescent light bulbs with light-emitting diodes (LEDs) halts electricity demand growth for lighting (see Box 7.2 in Chapter 7). In addition, energy efficiency efforts continue to moderate demand for space and water heating. Although energy service demand rises in advanced economies, improvements in insulation and heat pump adoption see this demand satisfied more efficiently, limiting economy-wide electricity demand growth to 1 800 TWh over the period 2016-40. The service demand for residential space heating met by heat pumps grows by 165 TWh in the New Policies Scenario, yet due to the high efficiency of heat pumps, only 65 TWh of electricity is required to meet this additional demand. Within the largest source of electricity demand today, industrial electric motor systems, energy efficiency policies regulating motors and their associated end-use devices (e.g. pumps and fans) in key markets, such as the European Union and the United States, limit average annual demand growth in advanced economies to 0.7%.

Demand growth in developing economies

In developing economies, electricity demand climbs by almost 3% per year through to 2040, with industrial motor systems contributing a staggering 37% of demand growth in developing economies. India is the fastest growing market, with electricity demand increasing by over 5% per year, driven by the achievement of universal access to electricity by 2025[6], expanding household demand for energy services (especially cooling) as incomes rise, and increasing use of electric motor systems in industry (Table 6.1). Despite a significant slowdown of growth to 2.3%, China is expected to be the largest contributor to additional global electricity demand (see Chapter 13). Nonetheless, continued efforts in energy efficiency in China and the growing role of the services sector in the economy significantly restrain demand growth, with energy efficiency expected to lead to a cumulative reduction in electricity demand of almost 2 000 TWh over the period 2016-40, equivalent to over a fifth of 2040 electricity demand in China. Economic transition and the increasing contribution to the gross domestic product (GDP) of the services sector also rein in growth, since industrial activity in developing economies as a whole is five-times more electricity intensive than activity in the services sector, and nearly ten-times more intensive in China.

Although the relative importance of the industry sector in certain economies, such as China, is decreasing, electric motor systems and electrification of heat used in industry continue to drive demand growth across developing economies. Growing at nearly 3% per year, motor system demand almost doubles by 2040, remaining by far the largest end-use in developing economies. Meanwhile the share of electricity use in developing economies to meet industrial heat demand grows from almost 3% today to 4.5% in 2040, representing an additional electricity demand of over 700 TWh by 2040. Nonetheless, thanks to economy-wide efficiency improvements, growth in electricity use slows considerably in the developing world, relative to historical trends (see Chapter 7). Demand growth is also driven by space cooling as the middle class expands and unit costs for air conditioners fall, so that space cooling demand in the buildings sector rises by 170% (Figure 6.4). Space cooling demand grows fastest in sub-Saharan Africa (excluding South Africa), at 7.4% per year, while China's cooling demand increases by 700 TWh by 2040, the largest absolute increase worldwide, with cooling demand in China exceeding the total electricity demand of Japan today. India also sees rapid expansion of demand for space cooling, which increases to over 15% of electricity demand in India in 2040.

6. For more information on access to electricity, see *Energy Access Outlook: from Poverty to Prosperity, World Energy Outlook Special Report* (IEA, 2017b).

Table 6.1 ▷ Electricity demand by region and scenario (TWh)

				New Policies						Current Policies		Sustainable Development	
	2000	2016	CAAGR 2000-2016	2020	2025	2030	2035	2040	CAAGR 2016-2040	2040	CAAGR 2016-2040	2040	CAAGR 2016-2040
North America	4 261	4 694	0.6%	4 866	5 017	5 208	5 417	5 651	0.8%	5 980	1.0%	5 505	0.7%
United States	3 590	3 886	0.5%	4 027	4 131	4 266	4 409	4 570	0.7%	4 846	0.9%	4 545	0.7%
C & S America	660	1 063	3.0%	1 164	1 308	1 479	1 664	1 858	2.4%	1 987	2.6%	1 733	2.1%
Brazil	327	512	2.8%	559	617	690	769	852	2.1%	918	2.5%	827	2.0%
Europe	3 114	3 555	0.8%	3 698	3 790	3 902	4 041	4 194	0.7%	4 522	1.0%	4 005	0.5%
European Union	2 605	2 857	0.6%	2 947	2 980	3 026	3 096	3 178	0.4%	3 436	0.8%	3 090	0.3%
Africa	385	655	3.4%	736	885	1 099	1 371	1 707	4.1%	1 608	3.8%	1 753	4.2%
South Africa	190	207	0.5%	221	240	267	299	335	2.0%	359	2.3%	275	1.2%
Middle East	359	910	6.0%	974	1 118	1 337	1 576	1 798	2.9%	1 976	3.3%	1 621	2.4%
Eurasia	809	1 065	1.7%	1 120	1 193	1 273	1 354	1 432	1.2%	1 506	1.5%	1 248	0.7%
Russia	677	865	1.5%	896	934	985	1 030	1 069	0.9%	1 126	1.1%	946	0.4%
Asia Pacific	3 611	9 433	6.2%	10 738	12 551	14 434	16 199	17 827	2.7%	19 258	3.0%	16 155	2.3%
China	1 174	5 320	9.9%	6 087	7 018	7 905	8 645	9 230	2.3%	10 279	2.8%	8 260	1.8%
India	376	1 102	6.9%	1 383	1 880	2 449	3 033	3 606	5.1%	3 732	5.2%	3 350	4.7%
Japan	1 005	969	-0.2%	962	967	978	991	1 005	0.2%	1 043	0.3%	855	-0.5%
Southeast Asia	322	837	6.2%	993	1 214	1 461	1 718	1 997	3.7%	2 105	3.9%	1 828	3.3%
World	**13 199**	**21 375**	**3.1%**	**23 295**	**25 861**	**28 733**	**31 622**	**34 467**	**2.0%**	**36 837**	**2.3%**	**32 022**	**1.7%**

Notes: Electricity demand is defined as the total gross volume of electricity generated, less own use in the production of electricity, plus net trade (imports less exports), less transmission and distribution losses. CAAGR = compound average annual growth rate. C & S America = Central and South America.

Electrification of the transport sector also contributes to rising electricity demand: electricity consumption for road transport is projected to expand by 300% in the New Policies Scenario to nearly 490 TWh, led by increasing demand from EVs as they grow to represent 14% of all passenger cars on the road in 2040. China leads the electrification of transport in developing economies, nearly tripling road transport electricity demand to 342 TWh, while India and Indonesia see the share of EVs rising to 13% and 7% respectively.

Although starting from a smaller share than in advanced economies, demand for ICT and small appliance loads in developing economies more than doubles in the New Policies Scenario, making up 8% of total demand by 2040. Increasing demand for ICT and small appliance loads is driven by rising ownership of radios, televisions, computers and, of course, mobile phones, among the 700 million people who gain access to electricity for the first time, as well as by households with an existing electricity connection. Expanding access to clean cooking contributes to a near-doubling of electricity demand for cooking by 2040. Concurrently, continued energy efficiency efforts limit growth in electricity demand from large appliances, such as refrigerators and washing machines. The effects of energy efficiency are also felt in space heating and water heating end-uses, with their share in final demand decreasing as heat pumps increasingly replace resistance heating. As a result of energy efficiency efforts, electricity intensity in buildings in developing economies stabilises at much lower values than in advanced economies, reaching 60 kilowatt-hours (kWh) per $1 000 of GDP in 2040, relative to 120 kWh in advanced economies today, and 90 kWh per $1 000 of GDP in 2040.

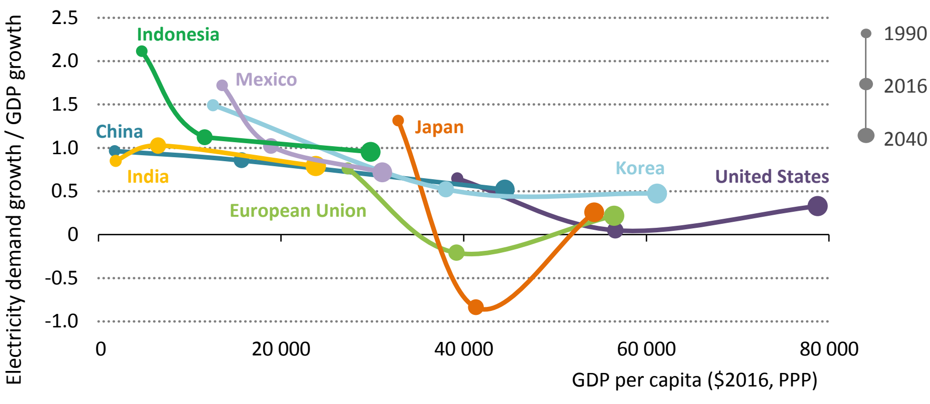
6

6.2.3 Electricity demand and economic growth

Economic growth continues to be a strong driver of electricity demand growth, and prior to the global financial crisis in 2008, a 1% rise in global economic growth required an increase of close to 1% in global electricity demand. However, the link is weakening and the relationship between GDP growth and electricity demand has even been negative in certain regions after the start of the financial crisis (Figure 6.5). Globally in the New Policies Scenario, electricity demand is projected to grow by 60%, while GDP grows by 124% by 2040, meaning that less electricity is required to produce each unit of economic output than in the past. This is the case despite greater electrification and the return of electricity demand growth in advanced economies, as they resume smooth and sustained economic development. Decoupling of electricity demand and economic growth is driven by structural transformation and by enhanced energy efficiency efforts globally. The transition towards a more services-oriented economy is central to the decoupling story, especially in developing economies, since the electricity intensity of the services sector today is globally four-times lower than the electricity intensity of the industrial sector. However there are significant regional variations.

In developing economies, prior to the global financial crisis, electricity demand was growing as fast as GDP: a 1% increase of GDP resulted in a 1% increase of electricity demand. This ratio fell below 1% in the post crisis period and is expected to decline further, as the shift towards services in economies gathers pace, driven by China. In the New Policies Scenario developing economies are projected to see GDP grow by over 180% to 2040, while power demand increases by slightly less than 100%. Decoupling continues despite greater electrification and growing residential demand for electricity services as incomes rise, and access to electricity is gained by many of the almost 1.1 billion people who still lack access. The speed of decoupling in developing economies highlights the important role of energy efficiency and technological progress in reducing the amount of electricity needed to fuel development, in addition to the impact of structural transformation.

Figure 6.5 ▷ Relationship between electricity intensity of the economy and income, historically and in the New Policies Scenario



The electricity intensity of the economy is declining at a global level, however electrification of new end-uses results in a rebound in advanced economies.

Notes: PPP = purchasing power parity. Points represent the GDP per capita at the indicated year, while the average of ratios of electricity demand growth to GDP growth is taken over representative periods; 1990-2007 for the year 1990, 2008-2016 for the year 2016 and the New Policies Scenario projection period (2017-2040) for the year 2040.

6.3 Electricity supply

6.3.1 Recent policy developments

Government policies play a substantial role in shaping the supply of electricity and recent months have brought a host of policy updates for major regions. The latest policies considered in the New Policies Scenario include formal planning documents from China and India, as well as signalled intentions on energy policies from newly elected administrations in Korea and France. Collectively, these policies continue the evolution of the power mix that has already started, in most cases looking to new technologies to reduce the environmental impact associated with meeting the growing demands for electricity.

Recent policy changes add to current momentum for renewables, furthering what has become a global phenomenon (Table 6.2). China and India have confirmed their commitment to rapidly scale up renewable energy to help meet growing electricity demand while addressing air pollution concerns. Korea and France, according to indications from new administrations, are now looking more to renewables rather than nuclear power to meet carbon-dioxide (CO_2) emissions reduction targets submitted to the United Nations Framework Convention on Climate Change under the Paris Agreement. Taken together, these policies are set to further the success of wind and solar PV, as they are particularly fuelled by strong policy support. The notable exception to the rule is the United States, where the announced intentions of the new administration to remove the Clean Power Plan would eliminate binding CO_2 emission targets, resetting the long-term trajectory for fossil fuels and low-carbon sources in the US power sector (Box 6.1).

6

Table 6.2 ▷ Recent developments in regional power sector policies included in the New Policies Scenario

Region	Policy	Authority	Release date	Impact on outlook by source			
				Renewables	Nuclear	Gas	Coal
China	13th Electricity Development Five-Year Plan (to 2020)	NEA	December 2016	↑	↑	↑	↓
India	Draft National Electricity Plan (to 2022)	CEA	December 2016	↑	↑	↑	↓
Korea	Proposed energy pillars (to 2025)	New admin.	2017	↑	↓	↑	↓
France	Announced energy policy (to 2025)	New admin.	2017	↑	↓	–	↓
European Union	No new coal power plants post-2020	26 of 28 countries	2017	–	–	↑	↓
Indonesia	PLN electricity supply business plan (2017-2026)	PLN	March 2017	↑	↑	↑	↓
Canada	Phase out traditional coal-fired power plants by 2030	New admin.	November 2016	↑	–	↑	↓
United States*	Removal of Clean Power Plan (to 2030)	New admin.	2017	↓	–	↓	↑

*For the United States, impacts are indicated relative to the case in which the Clean Power Plan is enforced.

Note: NEA = National Energy Administration in China; CEA = Central Electricity Authority in India; admin. = administration; PLN = Perusahaan Listrik Negara, the state electricity company in Indonesia.

The latest set of policy changes also generally seeks to reduce the reliance on coal-fired power plants. A key motivation, particularly emphasised in China, India and Korea, is to improve air quality by reducing air pollution from electricity generation. The European Union intends to go further, with nearly all member countries committing not to build new coal-fired power plants after 2020. Joining the United Kingdom in still more aggressive action, France and Canada aim to eliminate traditional coal-fired electricity generation completely by 2025 and 2030 respectively. Again, the United States stands outside this trend, signalling more flexibility to use coal in electricity generation in the long term.

Aside from renewables and coal, the impact of recent policies is less uniform. For nuclear, the latest policies are mixed, with a confirmed intention to scale up the use of nuclear power in China and India set against signalled intentions to reduce the reliance on nuclear power in France and Korea, two countries that have been leaders in the nuclear industry. The outlook for natural gas is generally improved by the recent changes. In many cases, natural gas is the source that fills the gap left by policies to reduce reliance on coal or nuclear, and raise the contribution of renewables. Historically low prices for natural gas in many markets are serving to encourage both gas exporters and importers to increase their use of gas in the power sector.

Box 6.1 ▷ Changing policy and market landscape in the United States

As the second-largest energy consumer in the world today, the policies adopted by the United States have significant implications for the global energy economy. Over recent years, the United States had enacted a number of state- and federal-level policies designed to reduce CO_2 emissions and diversify the power mix. At the federal level, the Clean Power Plan provided strong incentives for states to reduce the carbon-intensity of electricity supplies through measures which include energy efficiency, fuel switching (mainly from coal to gas), and the promotion of nuclear power and renewables. In addition, Carbon Pollution Standards for New Power Plants set CO_2 emission standards for new fossil-fuelled power plants, while production and investment tax credits, which have been effective in supporting wind and solar PV, were extended.

However, in March 2017, the new federal administration issued executive orders directing the US Environmental Protection Agency (EPA) to review the Clean Power Plan and Carbon Pollution Standards, with the stated intention of suspending, revising or abolishing regulations that unduly burden domestic energy resource development. This review could be expected to modify policies designed to reduce emissions from both existing and new power plants. In the absence of implementation of the Clean Power Plan and Carbon Pollution Standards, limits on the use of unabated coal-fired power plants would be removed, expanding opportunities to continue to run coal-fired plants in the long term and reducing opportunities for low-carbon technologies.

Many states are, nonetheless, pursuing their own energy strategies, led by some of the largest states. California is pursuing ambitious renewable energy goals: 33% by 2020 and 50% by 2030, and actively considering a drive towards 100% clean energy by 2045. Texas, which produced more non-hydro renewable energy in 2016 than any other US state, has already exceeded its target for renewable energy capacity by 2025. Hawaii, Massachusetts, New York, Oregon, Vermont and 22 other states, plus the District of Columbia, are also aiming to raise the share of renewables in their energy mix. Complementing these policies, about 20 states are moving forward with implementation plans for the Clean Power Plan. On the other hand, 20 states have stopped the development of their compliance plans.

Low natural gas prices and the financial difficulties in the nuclear industry are also contributing to the reshaping of the US energy outlook. In 2016, the average price for gas delivered to power plants fell below $3 per million British thermal units (MBtu), down 10% from the previous year. This sparked additional coal-to-gas switching, to the extent that in 2016 gas-fired electricity generation exceeded that of coal for the first time. Related to natural gas prices, wholesale electricity market prices have been very low, a positive development for consumers, but a competitive challenge for other market participants. In particular, the financial strain of lost revenue has been felt by nuclear power plants operating in these markets, to the extent that exceptional measures were taken in two states (New York and Illinois) to avoid the early retirement of several nuclear plants. The prospects of expanding the fleet of nuclear power plants have weakened: financial difficulties for nuclear developers have stopped work on two of the four reactors currently under construction.

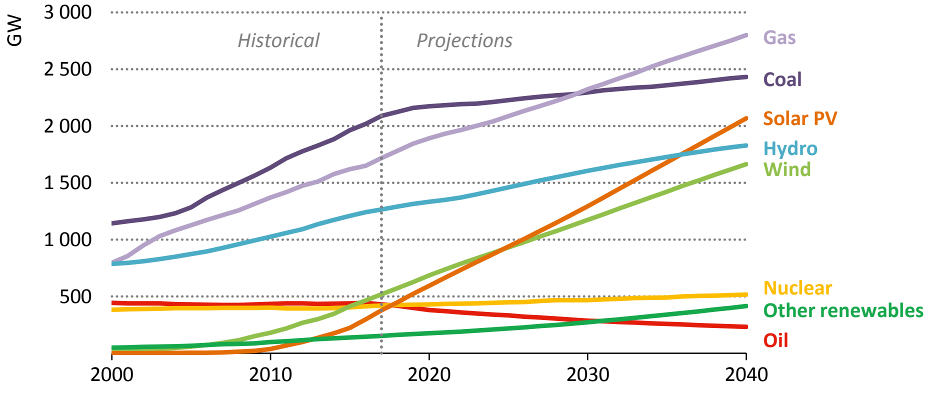
In addition to a broad shift in technology preferences, there are also transitions in policy preferences occurring. A key driver is that renewable energy technologies continue to improve, with implications for the policies supporting their deployment. The costs of renewables continue to fall, making renewable energy increasingly competitive with other sources of electricity and poised to move into a new phase of deployment, less reliant on government intervention. In 2016, the global weighted average capital cost of solar PV fell by 20%, compared with the year before. Wind power costs have also improved in recent years, with the promise of strong cost reductions still to come, particularly for offshore wind projects. Policies supporting the deployment of renewables are increasingly focused on encouraging competition between those bidding for long-term contracts, which provide them with a degree of insulation from market price risk. This enables them to attract low-cost financing, and minimise the eventual cost of support to consumers or taxpayers. This competition provides for achieving renewable energy targets at lower cost to consumers and, in some cases, taxpayers.

The clean energy transition in the power sector, accelerated by recent policies, raises questions about the ability of the power market, as currently designed, to deliver a reliable supply of electricity. All supply technologies are already finding it difficult to mobilise investment based on market-based revenues alone, in part due to the increasing share in the mix of variable renewables – mainly wind power and solar PV – but also due to low natural gas prices. In 2016, 94% of the global power sector investment, including for renewables, was made by companies operating under fully regulated revenues or mechanisms to manage the revenue risk associated with wholesale electricity market pricing (IEA, 2017c). These challenges will persist, risking under-investment in the new power plants needed to ensure the reliability of the electricity supply, until electricity market designs are able to catch up with the evolving power mix (see section 6.3.3).

6.3.2 Power generation capacity

The type of power plants that are being built around the world is changing. Fossil-fuelled power plants have long dominated the power sector but, after the projects currently under construction are completed, fossil fuels, and especially coal, lose considerable ground. In the New Policies Scenario, natural gas overtakes coal in global capacity by 2030, while among renewables, solar PV overtakes wind power by 2025 (Figure 6.6). By 2040, global solar PV capacity in the New Policies Scenario exceeds that of hydropower (though electricity generation from hydropower remains double that of solar PV in 2040).[7]

Figure 6.6 ▷ Installed power generation capacity by type in the New Policies Scenario

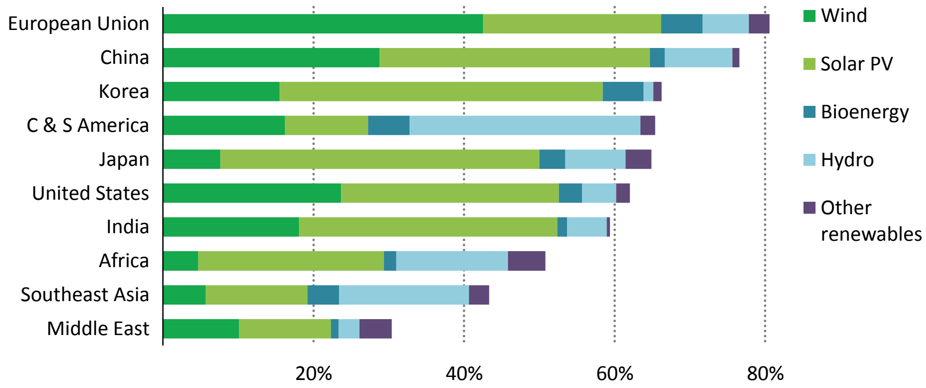


The New Policies Scenario reshuffles the leaders in power generation capacity; by 2030, gas surpasses coal while wind and solar PV gain ground

In 2016, global capacity additions of renewables exceeded additions of all fossil-fuelled power plants, marking a turning point in the power sector. This trend is strongly confirmed in the New Policies Scenario, as policies in place or under consideration lead renewables to account for more than 60% of global capacity additions over the period to 2040 (including replacing retirements). Renewables also represent the majority of capacity additions in most regions (Figure 6.7). In the European Union, renewables are projected to account for over 80% of the new power generation capacity built to 2040, led by onshore and offshore wind (Box 6.3). China has stepped to the forefront and become a leader in renewable energy over the past five years. To 2040, more than three-quarters of capacity additions in China are renewables-based technologies, helping it to maintain its position as the largest market for renewable energy.

7. The amount of electricity produced annually from a unit of capacity varies widely across technologies. For example, in 2016, 1 GW of solar PV capacity produced 1.0 TWh of electricity on average worldwide, compared with 2.1 TWh for each GW of wind power, 3.3 TWh for each GW of hydropower, 4.6 TWh for each GW of coal-fired capacity and 6.3 TWh for each GW of nuclear capacity.

Figure 6.7 ▷ **Share of renewables in total capacity additions by region in the New Policies Scenario, 2017-2040**



Renewables are a global phenomenon, representing the majority of capacity additions to 2040 in most regions of the world

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

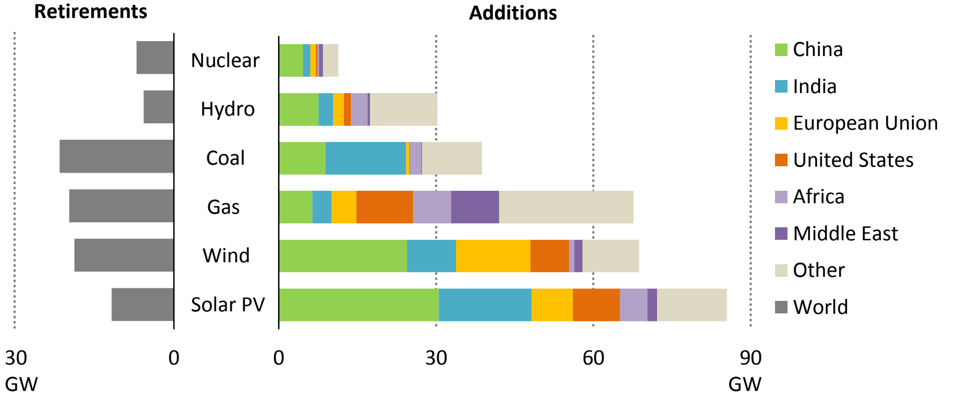
The outlook for solar PV has brightened in recent months, largely due to improved prospects in China and India. In the New Policies Scenario, solar PV capacity reaches 740 GW in 2040 in China, about 50% higher than in the *WEO-2016*, and tops 420 GW in India, twice the level reached in previous projections. Together, they account for close to three-quarters of the overall upward revision for solar PV. Record levels of deployment in both countries in 2016 raise the near-term trajectory, while recent policy changes and new long-term guidance indicate more sustained growth. In China, the solar PV target has been reframed as a minimum in the 13th Five-Year Plan and ambitions for the long term have been set out in the Energy Production and Consumption Revolution Strategy. In India, the National Electricity Plan sets official targets for 2022 and provisional guidance for 2027, and the government recently took steps to convert ambitions into reality by doubling the solar park capacity target, supporting the development of utility-scale projects. Lower projected costs for solar PV also contribute to the upward revisions, with significant cost reductions linked to aggressive deployment in the medium term, making solar PV one of the lowest cost technologies in both regions by 2030 (see section 6.3.7).

Solar PV is set to account for the largest share of renewable energy capacity additions in several regions, including Africa, China, India, Japan, Korea, Middle East and the United States. India's ambitious targets for solar PV and renewables look to reduce its reliance on coal. In Japan, solar PV dominates capacity growth in pursuit of a 2030 target of 7% of electricity generation, set as part of a broader renewable energy goal (22-24% of generation) in the National Energy Plan. In Korea, a new administration is looking to reshape the power sector, including aggressive targets for renewables. Solar PV is expected to play a lead role, as there are limited opportunities for other renewable energy technologies in the country.

In the United States, solar PV (and wind power) is set for strong growth over the medium term, but then capacity growth slows, on the assumption that the Clean Power Plan is not implemented at the federal level. State-level action and competitive costs help renewables remain relevant in the long term.

Hydropower capacity continues to grow in all regions, and plays an important role in expanding electricity supply in developing economies. China is again the leader in terms of capacity expansion, with over 180 GW of new capacity added to 2040, alongside the massive buildout of wind and solar PV. In Central and South America, hydropower represents the largest share of capacity additions to 2040, tapping into high-quality resources. Sub-Saharan Africa, with several large-scale projects under development, is looking to hydropower as a means of affordably expanding centralised electricity supply, complementing efforts to provide electricity access to tens of millions through mini-grid and off-grid solar PV systems (IEA, 2017b). In Southeast Asia, hydropower capacity more than doubles to 2040 in the New Policies Scenario, both to meet domestic demand and for export (IEA, 2017d). Hydropower capacity continues to expand in advanced economies as well, though expansion is mainly achieved through upgrading and re-powering existing dams, rather than developing new projects.

Figure 6.8 ▷ Global average annual capacity additions and retirements by technology in the New Policies Scenario, 2017-2040



After a century of dominance, fossil-fuelled power plants no longer lead, as renewables account for more than 60% of total capacity additions to 2040

In the New Policies Scenario, the fleet of fossil-fuelled power plants continues to expand to 2040. On average, each year to 2040 sees 68 GW of gas-fired power generation capacity come online worldwide, plus 39 GW of coal-fired power plants and 4 GW of oil-fired capacity (Figure 6.8). Among fossil fuels, gas-fired power plants continue to be the option of choice in many regions, thanks to the low upfront investment costs of new gas-fired power plants, the speed at which they can be built and the increasing availability of gas at moderate prices in many markets. Gas-fired power plants also offer particularly flexible operations that suits them well to a future with increasing contributions from variable renewables. Gas is also favoured due to its low CO_2 and pollutant emissions relative to coal- and oil-fired power plants. Once king, coal steps back from its leading role. With many plants under construction, global coal-fired capacity additions are close to 70 GW per year on average to 2020 (four-fifths of the pace set over the past decade). However, from 2021 to 2040, the capacity of new build coal-fired power plants slows to 33 GW per year, while the rate of retirements is 20 GW per year. With clear policies in most advanced economies targeting the reduction of coal use in electricity generation, the expansion of coal-fired power is mainly in developing economies, increasingly concentrated in Asia.

As of 2016, the European Union was the world leader in installed nuclear capacity with 127 GW, led by France (66 GW),[8] Germany (11.4 GW), United Kingdom (10.4 GW) and Sweden (10 GW). The United States had the second-largest fleet of nuclear power plants in the world (105 GW), followed by Japan, China and Russia.

In the New Policies Scenario, global nuclear capacity increases steadily from 413 GW in 2016 to near 520 GW by 2040, although the expansion is confined to a shrinking number of regions. Moreover, the global distribution of nuclear power changes significantly. Strong growth in China and India far outpaces reductions in the European Union, Japan and Korea. China more than triples capacity and becomes the leader in nuclear energy by 2030, surpassing the United States and the European Union (Figure 6.9). Nuclear capacity in the European Union falls by about one-third to 2040, in line with announced reductions in Belgium, France, Germany and Switzerland. The United States also sees declining nuclear capacity, as recent financial difficulties weigh heavily on the industry – the completion of the reactors actively under construction are outweighed by the retirement of many ageing power plants. India becomes one of the top-five leaders in nuclear energy, in pursuit of its ambitious target to reach 63 GW of capacity by 2032. In Russia, state support drives continued expansion of nuclear power from current levels to 34 GW by 2040, though slow electricity demand growth limits the opportunities for expansion. Japan sees a gradual re-introduction of nuclear plants, after operations were suspended following the accident at Fukushima Daiichi; operational capacity is just above 30 GW in 2040 in the New Policies Scenario, more than one-third below the levels reached prior to 2011. In Korea, in line with the recently announced change of policy following strong earthquakes in late 2016, the reliance on nuclear power is reduced over time. The completion of reactors currently under construction lifts the total nuclear capacity close to 30 GW in Korea in the medium term, after which the lack of lifetime extensions bring the nuclear power plant fleet down to just half that level by 2040.

8. All capacities indicated are in gross terms, before accounting for onsite use of electricity.

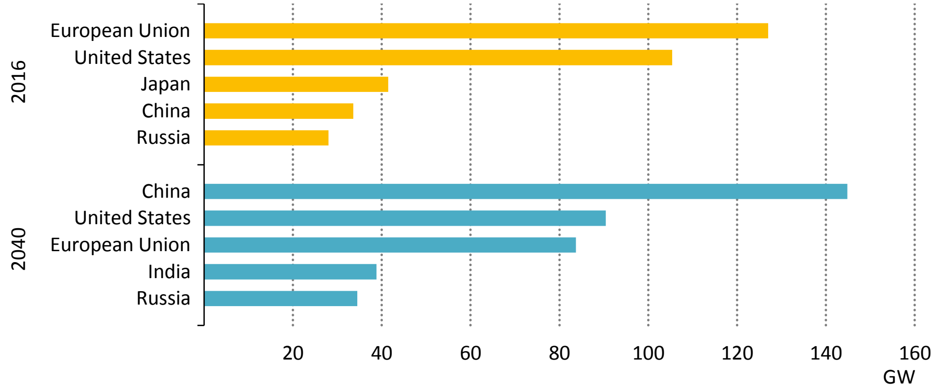
Table 6.3 ▷ Cumulative power plant capacity retirements by region and source in the New Policies Scenario, 2017-2040 (GW)

	2017-2025						2026-2040						2017-2040
	Coal	Gas	Oil	Nuclear	Renewables	Total	Coal	Gas	Oil	Nuclear	Renewables	Total	Total
North America	64	57	52	14	22	210	29	91	16	12	167	315	524
United States	58	51	43	11	17	180	22	88	8	12	140	270	450
Central & South America	1	5	9	0	4	19	3	8	10	1	28	50	70
Brazil	0	1	1	-	3	5	1	0	1	1	17	20	25
Europe	67	14	31	27	39	179	101	47	18	56	292	514	693
European Union	45	7	26	26	34	137	83	40	15	43	272	454	591
Africa	8	3	11	-	2	23	25	15	10	2	9	61	84
South Africa	8	-	1	-	0	8	24	0	0	2	3	29	37
Middle East	0	11	12	-	0	23	0	31	27	-	1	59	83
Eurasia	25	55	4	8	0	93	30	46	5	12	4	97	189
Russia	21	47	2	8	0	78	22	41	2	12	3	80	158
Asia Pacific	49	26	32	20	17	144	115	64	59	16	364	618	762
China	25	0	1	-	4	30	46	1	3	-	236	287	317
India	7	0	0	0	2	10	34	7	9	1	43	94	104
Japan	7	17	20	10	5	59	10	22	19	5	47	104	162
Southeast Asia	0	2	5	-	3	10	5	18	16	-	12	51	61
World	**215**	**172**	**151**	**70**	**84**	**692**	**302**	**302**	**144**	**100**	**866**	**1 714**	**2 405**

Table 6.4 ▷ **Cumulative gross power plant capacity additions by region and source in the New Policies Scenario, 2017-2040** (GW)

	2017-2025						2026-2040						2017-2040
	Coal	Gas	Oil	Nuclear	Renewables	Total	Coal	Gas	Oil	Nuclear	Renewables	Total	Total
North America	3	137	8	3	213	365	0	208	6	7	349	569	934
United States	2	107	7	3	175	295	-	153	5	5	287	450	745
Central & South America	5	26	2	2	69	105	5	66	3	4	144	222	327
Brazil	1	6	0	1	35	44	0	6	2	3	72	82	126
Europe	34	44	1	8	222	309	22	124	2	32	517	697	1 007
European Union	11	26	0	4	183	224	5	88	1	21	462	577	801
Africa	18	57	10	-	57	143	32	115	11	7	202	366	509
South Africa	13	3	0	-	8	24	24	7	0	7	23	61	85
Middle East	3	81	12	6	16	118	1	140	3	12	96	251	369
Eurasia	17	71	0	11	10	109	15	66	0	17	47	146	255
Russia	8	52	0	10	7	78	6	42	0	16	38	102	180
Asia Pacific	342	193	10	74	895	1 513	433	297	20	89	1 940	2 778	4 291
China	141	77	0	52	540	811	72	76	0	59	1 022	1 229	2 039
India	120	30	4	9	191	354	251	59	8	24	546	886	1 240
Japan	5	23	0	3	35	65	3	23	0	3	76	105	171
Southeast Asia	41	26	3	-	48	118	58	83	5	2	120	269	387
World	**422**	**609**	**43**	**105**	**1 484**	**2 662**	**508**	**1 015**	**44**	**168**	**3 294**	**5 030**	**7 692**

Figure 6.9 ▷ **Top-five regions by installed capacity of nuclear power plants in the New Policies Scenario**



The European Union steps down as the leader in nuclear energy, making way for China to take the lead

Across all fuels, close to 700 GW of power generation capacity is set to be retired worldwide by 2025 (Table 6.3), representing about 10% of all installed capacity today. By 2040, about 2 400 GW of capacity will have been retired worldwide in the New Policies Scenario, equivalent to more than one-third of the current global power plant fleet. Age accounts for most retirements, as more than 1 100 GW have already been operating for more than 40 years. Of these ageing power plants, almost 60% are fossil-fuelled – 320 GW of coal, about 200 GW of gas and 125 GW of oil – with standard operational lifetime of 50 years or less. Challenging market conditions contribute to the coming wave of retirements, as low natural gas prices and increasing renewables suppress wholesale electricity prices in many competitive markets, including in the United States and European Union, reducing revenues from energy sales for all market participants. Direct policy interventions also drive retirements, with specific targets to phase out coal and nuclear in several markets.

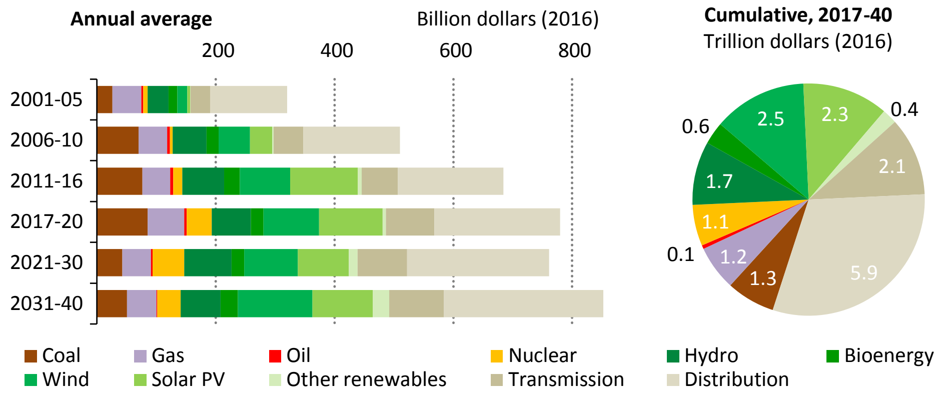
6.3.3 Investment

Over the period to 2040, cumulative investment in the power sector amounts to some $19.3 trillion, making up about 47% of overall investment in energy supply in the New Policies Scenario.[9] On an annual basis, an average of $800 billion per year is invested in new power plants and networks, as well as refurbishing and upgrading ageing infrastructure. This is a continuation of the rising investment trend in the power sector in recent years, the level of which exceeded $700 billion in 2015 and 2016. Investment in power plants makes up close to 60% of the total in the power sector, with the remaining portion invested in

9. Energy supply investment includes that for oil, gas, coal, biofuels and electricity supply.

transmission and distribution (T&D) networks to support the efficient delivery of supply (Figure 6.10). Distribution, the last step in the delivery of power to consumers, captures over 30% of total power sector investment to 2040. Power plant investment is dominated by renewables, as they account for two-thirds of the global total (wind and solar PV together make up close to 45%).

Figure 6.10 ▷ Global annual average power sector investment and cumulative investment to 2040 in the New Policies Scenario



Renewables make up two-thirds of total power plant investment, while continued network investment supports the efficiency and security of electricity supply

Developing economies account for two-thirds of global investment in the power sector in the New Policies Scenario, in order to meet growing electricity demand and to build the supporting infrastructure. Collectively, they account for the bulk of global investment in power plants (65% of the total), particularly coal (86%) and hydropower (78%), but also solar PV (65%), nuclear (63%), gas (61%) and wind (52%). China alone accounts for close to 30% of global wind power investment to 2040, while China and India make up 45% of solar PV investment. In advanced economies, an average of $280 billion per year to 2040 is invested in the power sector in the New Policies Scenario. While the total increase in electricity demand in advanced economies is only one-sixth that of developing economies, power plant investment is about half as much per year on average due to efforts to decarbonise electricity supply and the need to replace ageing power plants. Advanced economies make up close to 40% of global investment in renewables to 2040, and nearly half of the investment in wind power and bioenergy-based power plants. Within advanced economies, renewables account for almost three-quarters of power plant investment to 2040, and more than two-thirds of renewables investment goes to wind and solar PV. Gas-fired power accounts for 12% of the total, nuclear 10% (falling after 2030) and coal only 5%. Over 60% of power plant investment in advanced economies to 2040 is required just to maintain the status quo, replacing capacity retirements.

Table 6.5 ▷ Cumulative investment in the power sector by region and type in the New Policies Scenario, 2017-2040 ($2016 billion)

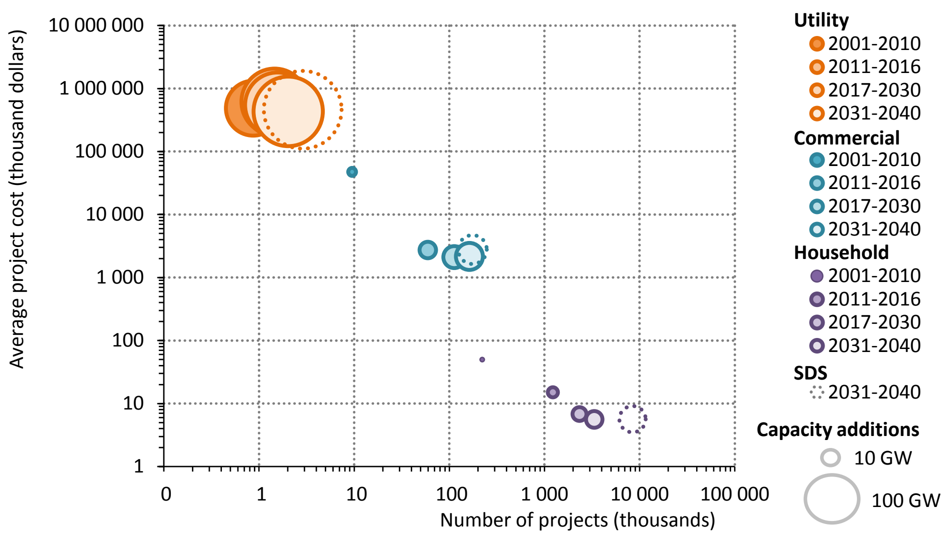
	2017-2025						2026-2040						2017-2040
	Fossil fuels	Nuclear	Renewables	Total plant	T&D	Total	Fossil fuels	Nuclear	Renewables	Total plant	T&D	Total	Total
North America	134	59	410	602	370	972	207	80	579	865	626	1 491	2 463
United States	108	43	340	491	311	802	162	65	477	704	497	1 201	2 003
Central & South America	26	9	139	173	154	327	54	16	275	346	304	651	978
Brazil	6	5	68	80	78	158	5	11	134	151	152	303	461
Europe	111	71	478	661	394	1 054	142	181	947	1 269	637	1 906	2 960
European Union	52	54	402	507	286	794	81	133	845	1 059	452	1 512	2 306
Africa	74	-	126	201	180	381	141	27	387	556	592	1 148	1 529
South Africa	23	-	17	40	20	60	46	27	43	116	61	177	237
Middle East	78	21	35	134	77	211	113	42	188	343	219	562	773
Eurasia	108	43	22	173	98	270	109	67	108	284	161	445	715
Russia	71	41	16	127	57	184	63	62	90	215	100	315	500
Asia Pacific	517	223	1 348	2 087	1 437	3 525	745	261	2 555	3 560	2 776	6 336	9 861
China	151	146	760	1 057	714	1 771	103	158	1 266	1 527	1 169	2 696	4 467
India	159	26	240	426	283	709	336	67	594	996	631	1 627	2 336
Japan	33	15	79	126	77	204	26	22	128	177	141	317	521
Southeast Asia	82	-	98	180	207	387	149	9	227	385	470	855	1 242
World	**1 048**	**426**	**2 558**	**4 031**	**2 710**	**6 741**	**1 510**	**674**	**5 039**	**7 223**	**5 315**	**12 538**	**19 279**

Note: T&D = transmission and distribution.

Worldwide network investments total $8.0 trillion from 2017 to 2040 in the New Policies Scenario (over $330 billion per year on average), with contrasting patterns between advanced and developing economies (Table 6.5). About 70% of global investment in T&D occurs in developing economies, where two-thirds of network investment is linked to expanding and reinforcing grid networks to meet growing demand. By contrast, close to two-thirds of network investment goes to replace ageing infrastructure in advanced economies. In both advanced and developing economies, investments to support expanding renewable energy supplies make up roughly 10% of total network investments.

Adequate investment in the long-term security of electricity supply is at stake in some regions, in the light of changing conditions in electricity markets. In particular, investment in utility-scale conventional generating capacity is becoming more risky in the face of the growth of variable renewables. Adding to the complex landscape is the expanding role for smaller players and smaller projects in electricity supply (Spotlight). For projects commissioned in 2015, less than 5% of fossil fuels, nuclear and hydropower capacity were owned by households, communities and auto-producers, while these entities owned 16% of new wind, solar and other non-hydro renewables (IEA, 2016a). However, while there is a proliferation of smaller projects in the New Policies Scenario, utility-scale projects continue to dominate electricity supply (Figure 6.11).

Figure 6.11 ▷ Average project cost, number of projects and capacity additions historically and projected in the New Policies Scenario



The number of power projects undertaken by smaller players continues to increase, yet utility-scale projects remain the backbone of the power system

Note: SDS = Sustainable Development Scenario.

SPOTLIGHT

The expanding role of smaller players in electricity supply

There has been a paradigm shift in the supply of electricity in recent years, with millions of households, along with communities and businesses, investing directly in their own supplies of electricity, most often in the form of renewables. Previously, the supply of electricity had been the exclusive domain of utilities, with large-scale power plants generating electricity and delivering it to consumers, often over long distances. The falling costs of solar PV and wind have made dedicated energy supply more affordable for consumers, leading to a proliferation of small-scale projects, with capacities of 10 kilowatts (kW) or less in most cases. Much smaller projects of less than one kW are being deployed in huge numbers as well, particularly in sub-Saharan Africa, where they often provide the first access to electricity for many communities. Collectively, households have accounted for about 6 GW of capacity additions annually since 2010, with the leading markets in the European Union, United States, Japan and Australia.

Beyond households, commercial entities and industry have directly financed wind and solar PV, often built onsite, or indirectly supported projects through power purchase agreements. These projects can reduce energy costs in some instances, help meet environmental goals and bolster the sponsor's environmental credentials. To date, increasing numbers of companies are undertaking to source 100% of their electricity consumption from renewables, including firms in the United States, European Union, China and India. Community co-operatives are growing in popularity, pooling resources to finance bigger investments, most often wind turbines or solar PV, to serve local loads and/or sell back to the grid. Micro-grids are becoming more widespread, not just to power remote communities or small islands, but also to serve grid-connected districts as a backup system for crucial business processes or community facilities (e.g. hospitals), to increase their resilience in the event of network outages.

Non-utility companies are using new technologies to compete with utilities to provide energy services to the market. Some small independent power producers are investing in solar PV and wind farms that are typically only tens of megawatts (MW) in size (compared to traditional fossil-fuelled plants of several hundred MW). Specialised energy storage companies are also entering electricity wholesale markets, primarily to provide frequency regulation services, unlike most generators, who derive the bulk of their revenue from the sale of energy.

The expanding role of smaller players is characterised by:

- Broad set of investors and developers.
- Small project sizes and relatively low investment requirements.
- Diverse interests, going well beyond pure financial considerations.
- Decentralised production, often onsite or located close to demand.

Looking forward, smaller players are set to further expand their contributions to electricity supply. In the New Policies Scenario, falling project costs help drive the expansion of the global market for rooftop solar PV, with installations increasing from an average of about 1 million projects per year since 2010 to over 2 million projects per year to 2030 and 3 million per year over the last decade of the outlook. The economics of rooftop solar PV are bolstered over time, due to declining solar PV costs and rising wholesale and end-user electricity prices in most regions (though reforms of electricity tariffs to make them more cost-reflective could make solar PV less attractive, and large-scale installations will also benefit from cost reductions). In addition, smart meters and cost reductions for energy storage, connected appliances and EVs enable consumers to consume onsite more of the electricity produced, further improving the economic case for solar PV. These considerations also support the continued expansion of commercial-scale projects by communities, businesses and non-utility energy companies, which are projected to collectively undertake well over 100 000 projects per year by 2030.

The expanding role of smaller players is attracting new sources of funding for energy projects. In addition to direct investment by households, communities and businesses, new financial products, such as green bonds, are becoming increasingly available. Investors in these instruments are looking for new avenues for investment, which provide reliable financial returns and help to meet corporate sustainability goals. About $80 billion worth of green bonds were issued in 2016, almost double of the value issued in 2015, and over $50 billion of this sum was dedicated to energy-related projects (IEA, 2017c). Crowdfunding – an emerging means of collecting funds from small investors to finance projects – has begun to be used for energy investments as well. Enabling consumers to meet their own electricity demands is helping to accelerate the transition towards clean energy across the world, in advanced economies and the poorest countries alike. The falling costs of renewables and the expanding diversity of financial solutions are contributing to the expansion of electricity access through off-grid and mini-grid solutions, particularly in rural areas in sub-Saharan Africa (see Chapter 3).

In the New Policies Scenario, a global average of about 270 GW of utility-scale projects is completed annually, accounting for more than 80% of total new capacity. Where electricity demand growth is modest and smaller players are taking more responsibility for supply, as in the European Union and some markets in the United States, the role of the central grid is moving towards that of supplementary supplier, with its revenue stream more at risk. To generate the necessary utility-scale investment, it may well be necessary to make market changes, for example to remunerate the provision of the balancing services vital to the network. Capacity mechanisms are a new design element being considered and tested in several wholesale electricity markets, intended to provide a fixed payment to sources that contribute to the adequacy of power supply. Encouraging competition among sources of flexibility, including energy storage, demand-side response and dispatchable power plants will serve to make market reforms more durable as technologies and market conditions evolve. The additional revenue streams would also serve to strengthen the financial situation of existing power plants and other sources of flexibility on the supply side, further supporting the reliability and security of electricity supply. Other countries that are looking to incorporate elements of liberalised markets into their own electricity markets, including China and Mexico, will need to address similar challenges.

Efficient T&D networks are essential to the security of electricity supply and may require change to support an efficient power system and to keep pace with the evolution of the power sector. Investment in T&D is highly regulated, making the regulatory regime an important determinant of investment in new network infrastructure and the upkeep of existing assets. The regulatory model of providing a specified rate of return, applied in many markets, is effective in encouraging new investment, but it requires informed oversight to avoid excessive spending. Networks also require continual investment in the upkeep of existing infrastructure to keep them operating efficiently, which is not always incentivised appropriately. Two broad trends – the growth of distributed renewables and the digitalisation of energy assets – are driving the power system towards greater complexity and connected operations, emphasising the importance of sophisticated network regulation and integrated planning.

6.3.4 Electricity generation

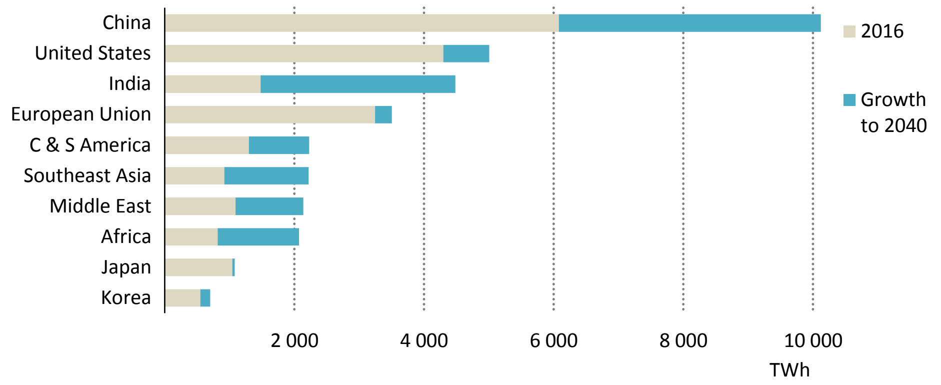
The way in which electricity supply evolves depends strongly on the nature of power sector policies. In the New Policies Scenario – reflecting current and proposed policies and measures on both the demand and supply side – global total electricity generation increases by just under 60% from 2016 to 2040 (Table 6.6). With many proposed policies incentivising renewables, their share of total generation increases from 24% in 2016 to 40% by 2040. With the contribution of nuclear power stable over time, the share of fossil fuels falls from two-thirds in 2016 to just over half by 2040. In the case of the Sustainable Development Scenario, more aggressive deployment of renewables and other clean energy technologies is required to meet climate, pollution and development-related goals. In this scenario, renewables account for over 60% of total generation by 2040, with nuclear power providing an additional 15%. Fossil-fuelled plants are progressively phased out, falling to just 22% of the total generation in 2040. Of the remaining fossil-fuelled generation in 2040, close to 30% comes from power plants equipped with carbon capture and storage (CCS), which reduces the CO_2 emissions per unit of output by an order of magnitude. Phasing out coal-fired power plants without CCS is an important element of the decarbonisation of electricity supply. In the Current Policies Scenario, in which only established policies are considered, changes in the power sector are much less pronounced. With less aggressive energy efficiency efforts, the needed electricity supply is 8% higher in 2040 than in the New Policies Scenario. Fossil fuels remain the source of the majority of electricity to 2040, their share reduced only gradually to 60%.

Table 6.6 ▷ World electricity generation by source and scenario (TWh)

			New Policies		Current Policies		Sustainable Development	
	2000	2016	2025	2040	2025	2040	2025	2040
Total	**15 477**	**24 765**	**29 657**	**39 290**	**30 724**	**42 321**	**28 226**	**35 981**
Fossil fuels	10 017	16 136	17 124	19 758	18 666	25 336	14 071	7 971
Coal	6 005	9 282	9 675	10 086	10 897	14 386	6 575	2 195
Gas	2 753	5 850	6 730	9 181	7 033	10 428	6 903	5 585
Oil	1 259	1 004	719	491	736	523	593	192
Nuclear	2 591	2 611	3 217	3 844	3 218	3 825	3 531	5 345
Renewables	2 869	6 018	9 316	15 688	8 840	13 160	10 625	22 664
Hydro	2 619	4 070	4 804	6 193	4 755	5 964	4 986	6 928
Bioenergy	164	566	867	1 424	833	1 211	952	1 807
Wind	31	981	2 192	4 270	1 983	3 358	2 785	6 950
Solar PV	1	303	1 264	3 162	1 096	2 192	1 629	5 265
Other renewables	53	98	188	638	173	436	274	1 715
Fossil fuels	*65%*	*65%*	*58%*	*50%*	*61%*	*60%*	*50%*	*22%*
Coal	*39%*	*37%*	*33%*	*26%*	*35%*	*34%*	*23%*	*6%*
Gas	*18%*	*24%*	*23%*	*23%*	*23%*	*25%*	*24%*	*16%*
Oil	*8%*	*4%*	*2%*	*1%*	*2%*	*1%*	*2%*	*1%*
Nuclear	*17%*	*11%*	*11%*	*10%*	*10%*	*9%*	*13%*	*15%*
Renewables	*19%*	*24%*	*31%*	*40%*	*29%*	*31%*	*38%*	*63%*
Hydro	*17%*	*16%*	*16%*	*16%*	*15%*	*14%*	*18%*	*19%*
Bioenergy	*1%*	*2%*	*3%*	*4%*	*3%*	*3%*	*3%*	*5%*
Wind	*0%*	*4%*	*7%*	*11%*	*6%*	*8%*	*10%*	*19%*
Solar PV	*0%*	*1%*	*4%*	*8%*	*4%*	*5%*	*6%*	*15%*
Other renewables	*0%*	*0%*	*1%*	*2%*	*1%*	*1%*	*1%*	*5%*

The absolute size of electricity markets is an important consideration when considering the impact of policies in the various regions on global fuel markets, technology development and global climate change. As of 2016, China was the largest market for electricity in the world, producing over 6 000 TWh in that year alone. The United States and European Union followed a notable distance behind, with some 30% and 45% less total electricity supply respectively. In the New Policies Scenario, even with the implementation of energy efficiency measures, electricity markets in China and India experience robust growth in absolute terms. Total generation increases in China by 4 000 TWh, nearly the size of the US electricity market today, while the growth in India is similar to the size of the European Union market today (Figure 6.12). Strong growth in other developing economies, notably Southeast Asia and Africa, indicates the importance of the policy choices to be made in these regions on global energy trends.

Figure 6.12 ▷ Total electricity generation by region in 2016 and growth to 2040 in the New Policies Scenario



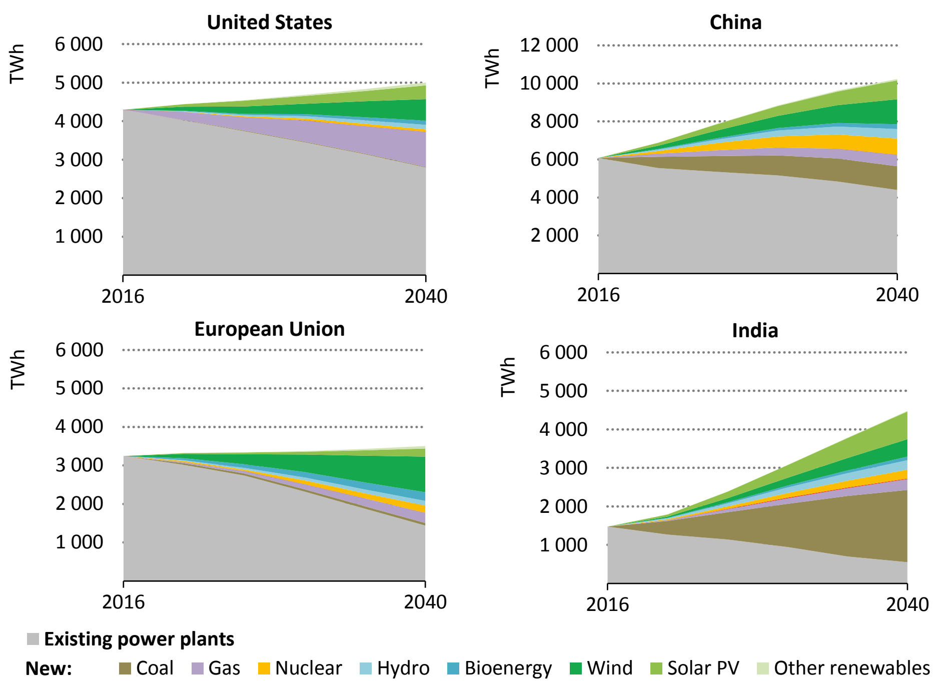
Electricity supply is set to increase by over 4 000 TWh in China, almost as much as US total generation today, while growth in India is nearly as much as the EU total today

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

Low-carbon technologies can reshape the power mix not only by meeting electricity demand growth, but also by replacing output from retired power plants and displacing output from fossil-fuelled power plants. In advanced economies, electricity supply growth is modest, but the retirement of ageing power plants provides opportunities for new sources of electricity. For example, in the European Union, the expansion of renewables-based electricity (over 1 500 TWh) far outpaces electricity supply growth to 2040, replacing lost output from retirements and displacing output from existing plants (Figure 6.13). Similarly, in the United States, the expansion of renewables notably exceeds the increase in electricity supply to 2040. Even where demand growth is strong, replacing ageing plants and displacing output from less efficient designs expand the market for new power plants. Renewables provide half of the overall increase in output from new power plants in China to 2040, and about 40% in India. The completion of many new nuclear reactors adds to the low-carbon electricity supply in China and India, as well as in South Africa and the Middle East.

By 2040, a diverse set of low-carbon technologies generate half of global electricity supply in the New Policies Scenario, 15 percentage points higher than in 2016 (Figure 6.14). Hydropower remains the largest low-carbon source of electricity to 2040, at 16% of global electricity generation throughout the period, though it makes a much larger contribution in Central and South America, Nordic countries and sub-Saharan Africa. Wind power surpasses nuclear to become the second-largest low-carbon source of electricity by 2040. It plays far and away the largest role in the European Union, reaching 27% of generation in 2040 due the strong growth of both onshore and offshore wind. Nuclear power provides about 10% of global electricity supply to 2040, with higher contributions in Japan, Russia, Korea, European Union, United States and several countries in Eastern Europe. Solar PV provided about 1% of global electricity supply in 2016. Widespread policy support and falling costs help raise its global share to 8% by 2040, and about twice that level in India and sub-Saharan Africa. Other renewable energy technologies – bioenergy, geothermal, concentrating solar power and marine power – continue to grow and reach 5% of global electricity supply by 2040. In the New Policies Scenario, limited deployment means that CCS-equipped power plants provide less than 1% of electricity supply to 2040. Expanded opportunities for CCS in the power sector could be unlocked through aggressive research and development programmes, broader support for low-carbon technologies or stringent CO_2 targets, as in the Sustainable Development Scenario.

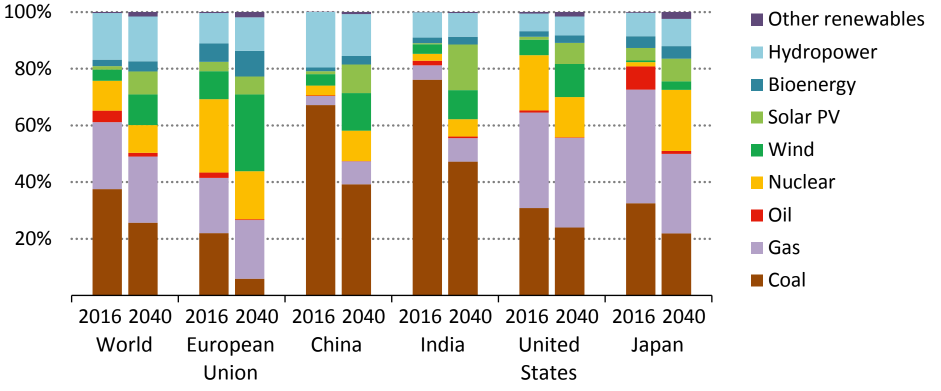
Figure 6.13 ▷ Electricity generation by existing and new power plants by type in the New Policies Scenario



Low-carbon technologies make up the majority of output from new power plants, reshaping power mixes around the world

As the share of variable renewables is set to increase in many markets, questions are being asked about the ability of power systems to cost-effectively integrate their output into electricity supply. Our analysis of the hourly balance of electricity supply and demand in the United States, European Union and India suggests that commonplace actions, mainly grid infrastructure upgrades and deployment of flexible forms of supply, are sufficient to fully integrate variable renewables up to about one-quarter of annual electricity supply, higher than the level reached in most regions in the New Policies Scenario (IEA, 2016b). Simulations examining sub-hourly intervals in a large portion of the US power system found that integrating up to 30% shares of wind and solar PV is feasible without advanced flexibility measures (Bloom et al., 2016). Furthermore, analysis indicates that this level of variable renewables can be integrated at little additional cost to the system in the long term (IEA, 2014). To this end, initiatives are underway to make sure that power plant flexibility is fully tapped (e.g. the Advanced Power Plant Flexibility Campaign by the Clean Energy Ministerial[10]). Beyond these levels, additional measures such as demand-side response and energy storage may be needed to ensure that the variable output from wind and solar PV are put to best use.

Figure 6.14 ▷ Share of total generation by type worldwide and in selected regions in the New Policies Scenario



Current and proposed policies strongly reshape the power mix in the New Policies Scenario, nearly doubling the share of renewables and driving down coal's contribution

While gas-fired electricity generation increases by close to 60% to 2040 in the New Policies Scenario, its share of total electricity supply holds steady at about 23%. The United States continues to produce the most electricity from gas-fired power plants to 2040, though the fuel's market share declines slightly, to less than one-third in 2040. The Middle East remains the second-largest market for gas-fired electricity, generating about two-thirds of its electricity from gas. In 2040, North Africa is the most reliant region on gas, at over 70% of total generation, followed by Mexico and Caspian countries where gas provides at least half of their electricity supply. In Japan, the re-introduction of nuclear reduces the need for fossil fuels in the power sector, driving down the share of gas from 40% in 2016 to below 30% in 2040. In the European Union, gas-fired power retains a market share of around 20%, in spite of strong carbon policies. In China and India, gas-fired generation rises substantially (China becomes the third-largest producer of gas-fired electricity by 2040), though gas provides less than 10% of generation to 2040 in both markets.

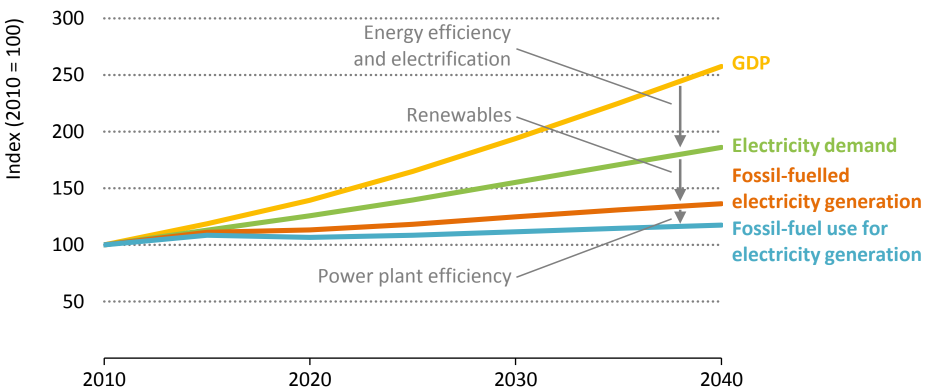
10. For more information, see *http://www.cleanenergyministerial.org/*.

Global coal-fired electricity generation is set to increase by less than 10% to 2040 in the New Policies Scenario (in stark contrast to the doubling over the last 25 years). In turn, coal's share of global electricity supply tumbles from 37% in 2016 to 26% in 2040, continuing the recent trend (down from 41% in 2014). The decline is most marked in the European Union, where coal's share falls from over 20% to just 6% by 2040, while in Japan, its share drops from 33% to 22%. In Korea, based on its new policy direction, the share of coal declines from over 40% of generation today to less than 15% by 2040. The United States sees a small reduction in coal-fired power, but coal's share slips from 31% in 2016 to 24% by 2040. US coal-fired output has already fallen almost 40% from its 2005 peak. While China and India mount major fuel diversification programmes, coal remains the primary source of electricity in both regions throughout the period to 2040. Combined, they generate more than 60% of global coal-fired electricity by 2040. India sees coal-fired power growing at around 3% per year to 2040, supplementing the growth of solar PV and other renewables. Southeast Asia sees coal's share rise by five percentage points to 2040, as coal-fired output nearly triples.

6.3.5 Fossil-fuel consumption in power

As discussed in section 6.2.3, a major change is occurring in the relationship between economic growth and electricity demand. Even in some major growing economies, such as China, recent power demand growth is well below that of GDP. A second trend can also be discerned: a falling ratio of fossil fuel inputs per unit of electricity demand (Figure 6.15). This is, in part, an obvious consequence of the rising share of renewables in electricity supply. However, it is also a result of ongoing efficiency improvements in fossil-fuelled power plants, notably coal and gas (oil-fired electricity generation declines in absolute and percentage terms, to about 1% of electricity supply in 2040).

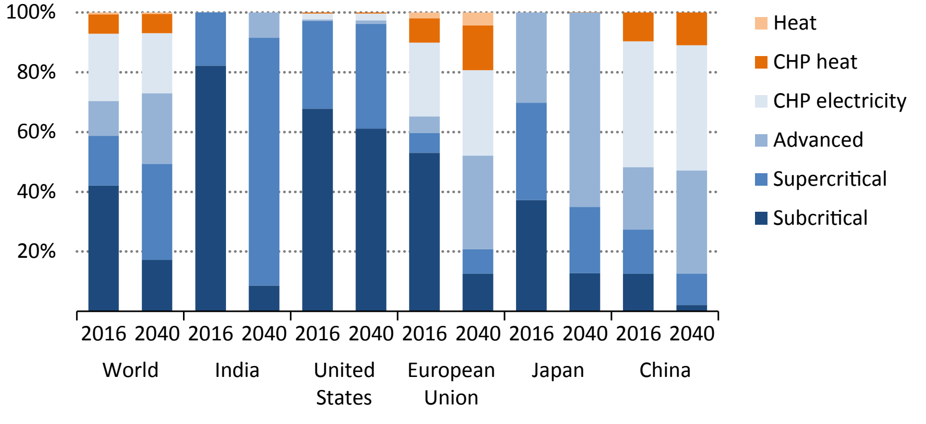
Figure 6.15 ▷ Decoupling of global GDP growth and fossil-fuel consumption in electricity generation in the New Policies Scenario



A three-stage decoupling is taking place in power, separating economic growth and the growth of electricity demand, fossil-fuelled generation and fossil-fuel consumption

While global coal-fired electricity production increases by 9% to 2040 in the New Policies, the amount of primary energy consumed in the process rises by just 1%. The improvement reflects the increasing contribution of more efficient supercritical and advanced technologies (Figure 6.16). In Japan, the fleet of coal-fired power plants has achieved the highest average efficiency (42%) in the world for producing electricity, with further gains expected. In China, the average efficiency of coal-fired generation (including highly efficient combined heat and power plants) has already improved sharply since 2000, from less than 37% to over 42% in 2016. Over the *Outlook* period, efficiency continues to improve (to 45%). Had coal plant efficiency remained at 2000 levels, by 2040 China would be consuming about 20% more coal than projected, an absolute increase of some 310 Mtce (about 6% of global coal consumption today). India sees plant efficiency rising from 35% today, to almost 40% by 2040, so that as generation increases by more than 85%, coal use rises by less than 70%. In the European Union, coal-fired power plants that produce electricity only are largely phased out in pursuit of CO_2 emission reductions.

Figure 6.16 ▷ Share of coal consumption by technology in electricity and heat production in the New Policies Scenario



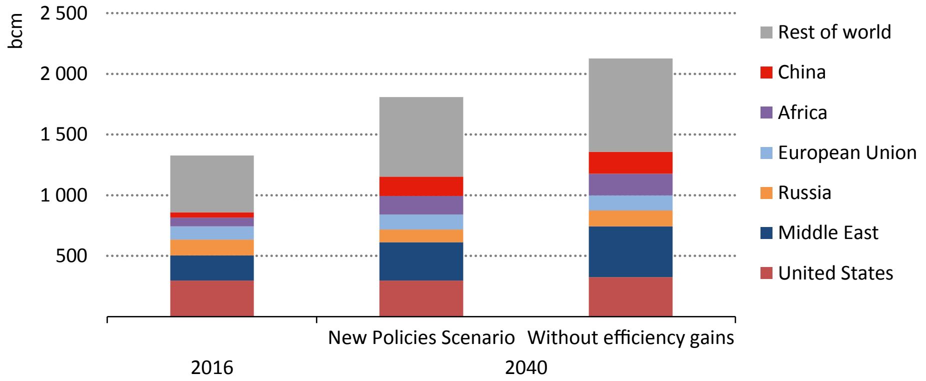
Coal plant efficiency gains are driven by reducing the use of the least efficient designs and shifting to new, higher temperature and pressure designs

Note: CHP = combined heat and power; Advanced = ultra-supercritical and integrated gasification combined-cycle designs.

In the case of natural gas, the global average efficiency in the power sector rises from just over 50% to beyond 55%, as the penetration of high efficiency combined-cycle designs increases. Improved efficiencies in more conventional steam and gas turbines also contribute to the improvement. However, the rising share of variable renewables in generation requires thermal plants to operate more flexibly, partially offsetting the potential efficiency gains. Overall, while gas-fired generation grows at 1.9% annually to

2040, the use of gas by the power sector grows at only around two-thirds of that rate, or 1.2%. In the case where the projected efficiency improvements do not eventuate, global natural gas use would be higher by some 275 billion cubic metres (bcm), more than twice the current total gas use in Japan (Figure 6.17). In the Middle East, efficiency gains make an important contribution to mitigating the increase in gas demand, as gas-fired generation nearly doubles.

Figure 6.17 ▷ Gas consumption in electricity generation with and without projected efficiency gains over time in the New Policies Scenario



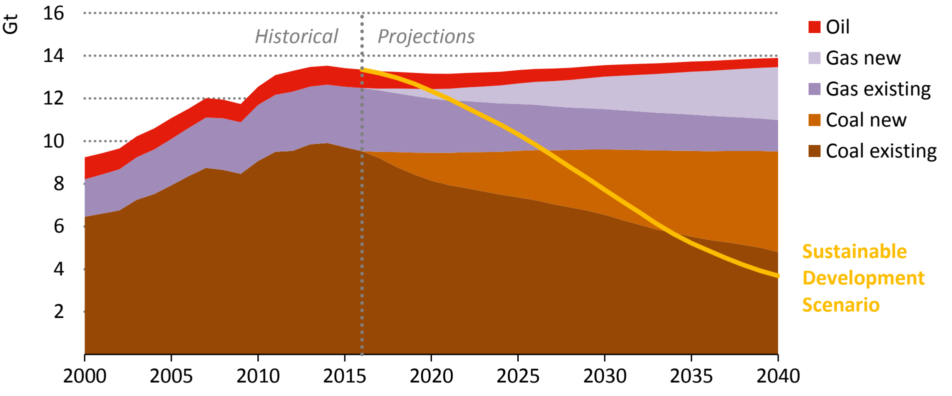
Natural gas use in electricity generation rises by 480 bcm to 2040, but without power plant efficiency gains the increase would be 275 bcm larger

6.3.6 Power sector CO_2 and pollutant emissions

Over the past three years, global power sector CO_2 emissions have declined slightly to 13.4 gigatonnes (Gt) in 2016 (including those related to both the production of electricity and heat). The reduction was driven by a fall in emissions from coal-fired power plants, a remarkable change from the near-doubling that took place since 1990. As the power sector accounts for more than 40% of global energy-related CO_2 emissions, this has helped global energy-related CO_2 emissions to stay flat since 2013. Within the power sector, the production of electricity accounts for over 90% of emissions. In the New Policies Scenario, even though electricity supply expands by almost 60% to 2040, related CO_2 emissions rise by just 4%. To achieve this, the global average CO_2 emissions intensity of electricity generation drops from 494 grammes of CO_2 per kilowatt-hour (g CO_2/kWh) in 2016 to below 330 g CO_2/kWh by 2040, slightly below the average for an efficient gas combined-cycle gas turbine (CCGT) power plant. Heat contributes the remaining share of CO_2 emissions from the power sector, and, over the projection period, global heat-related emissions increase by 3% worldwide.

In 2016, coal-fired power plants emitted 9.5 Gt of CO_2, accounting for more than 70% of power sector CO_2 emissions. In the New Policies Scenario, the average emissions intensity of coal-fired generation declines from 950 g CO_2/kWh today to 880 g CO_2/kWh in 2040, enabling CO_2 emissions from coal-fired generation to stay broadly flat to 2040, not returning to the high point set in 2014 (Figure 6.18). Nonetheless, from 2017 to 2040, existing coal plants emit more than 160 Gt CO_2, representing a significant challenge in the fight against climate change. Emissions from gas-fired power plants make up 22% of total power sector emissions today, with an average emissions intensity of 440 g CO_2/kWh, which falls to 385 g CO_2/kWh in 2040 due to efficiency gains. The use of oil accounts for the small amount of remaining emissions, though its use and related emissions are falling in most regions. In the Sustainable Development Scenario, CO_2 emissions in the power sector are rapidly reduced, with emissions in 2040 three-quarters lower than in the New Policies Scenario.

Figure 6.18 ▷ Global power sector CO_2 emissions by fuel in the New Policies Scenario

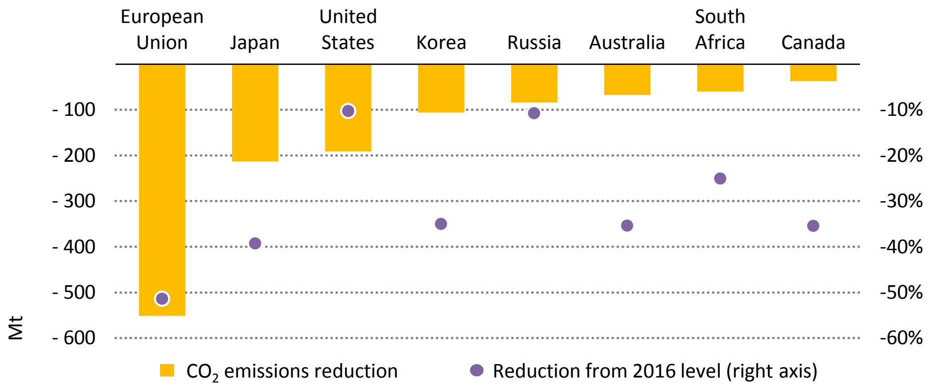


While CO_2 emissions from coal-fired electricity generation peaked in 2014, overall emissions in the power sector increase slightly by 2040

The evolution of CO_2 emissions varies widely across regions, with absolute reductions in many regions. The European Union leads the way, reducing power sector CO_2 emissions by more in absolute and percentage terms than any other region (Figure 6.19). Other countries reducing their power sector emissions by more than 30% from today's level are Japan, Korea, Australia and Canada, with South Africa achieving nearly the same rate of progress. While achieving a lower rate of reduction, the United States falls third in terms of absolute emission reductions in the power sector to 2040. Even though some regions do not achieve a reduction in the absolute level of emissions in 2040 in the New Policies

Scenario, all regions reduce their emissions intensity per unit of economic activity over time. Per unit of GDP, CO_2 emissions reductions of 60% or more are achieved in China, Mexico and Chile, while India and Brazil achieve more than 50% reductions.

Figure 6.19 ▷ Reduction of power sector CO_2 emissions in selected countries in the New Policies Scenario from 2016 to 2040

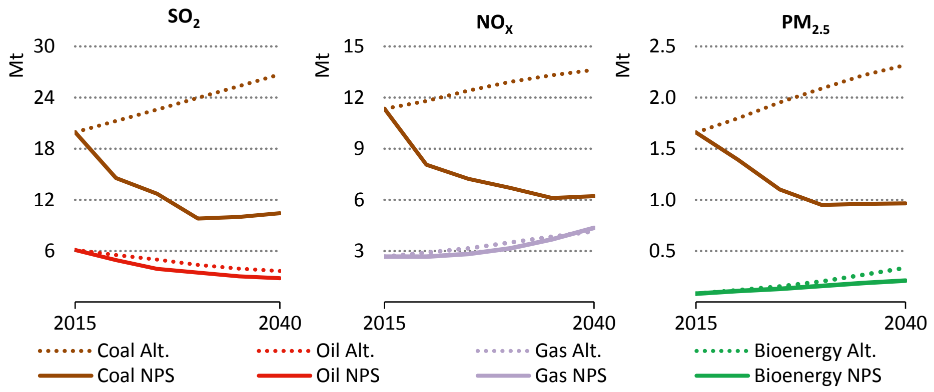


Current and proposed policies put the power sector at the forefront of the energy transition, reducing related CO_2 emissions in several markets

An important additional benefit of efforts to reduce fossil-fuel use in the power sector is lower emissions of the air pollutants that cause millions of premature deaths every year. With efficiency gains and more fossil-fuelled power plants equipped with control technologies, pollutant emissions are set to decline substantially. Without these improvements, emissions of sulfur dioxides (SO_2) and fine particulate matter ($PM_{2.5}$) from the same level of electricity and heat production would be twice as high by 2040, and nitrogen oxides (NO_X) emissions would be 60% higher (Figure 6.20).

Coal-fired power plants are the leading source of all primary air pollutants within the power sector, accounting for more than 70% of the total SO_2, NO_X and $PM_{2.5}$ emissions in 2015. Over the *Outlook* period, SO_2 emissions, together with $PM_{2.5}$ emissions, are reduced as the total of coal and oil consumption fall. In both cases, the declining trends are slightly offset by the increased use of bioenergy, which more than doubles by 2040. In the case of NO_X emissions, stronger dependence on natural gas in electricity supply means that overall emissions from the power sector in 2040 are reduced by 20% from the level in 2015. SO_2 and $PM_{2.5}$ intensities per unit of electricity generation are reduced by around 60% in the New Policies Scenario to 2040, while the intensity of NO_X is reduced by half. To 2030, greater use of control technologies rapidly reduces the emission intensities for all pollutants in most regions but, after that, the emission intensities continue to decrease slightly, while coal-fired generation increases in India and Southeast Asia.

Figure 6.20 ▷ Pollutant emissions in the power sector by fuel with and without enhanced pollution controls in the New Policies Scenario



Control technologies together with efficiency improvements help save over 50% of power-related SO_2 and $PM_{2.5}$ emissions, and close to 40% of NO_X emissions in 2040

Notes: NPS = New Policies Scenario. Alt. = alternative case in which there are no improvements in pollution control systems.

6.3.7 Technology costs and competitiveness

The evolution of technology costs, particularly for renewables, is one of the most important trends in the power sector. Strong policy support has enlarged the markets for renewables, setting the stage for improvements in manufacturing and research and development. These efforts have reduced the average levelised cost of electricity (LCOE) from solar PV by 70% from 2010 to 2016.[11] Overall cost reductions have been achieved through falling solar module costs and reduced setup costs, resulting from streamlined installation processes and gains in panel efficiency that reduce the physical size of solar arrays per unit of output. Project-level solar PV costs can vary widely between regions and within individual countries, in part due to resource inequalities but also due to various market conditions (Barbose, 2016). Based on the projected deployment of solar PV and assumed technology learning rates, the global average LCOE of solar PV declines by an additional 50% to 2030 in the New Policies Scenario, though substantial regional variations remain.[12] Many factors contribute to the variation, including the delivered cost of solar modules and resource quality, as well the costs of labour, land, marketing and permitting.

11. Historical LCOEs for solar PV and wind power technologies are based on historical capital costs and capacity factors provided by the International Renewable Energy Agency.

12. Projected technology costs for renewables, including assumed learning rates, along with technology cost assumptions for fossil fuels and nuclear power plants, are available at: *www.iea.org/weo/weomodel/*.

Wind power has also seen substantial cost reductions, 25% from 2010 to 2016, in part due to improved performance as installations have grown far taller and the turbine blades have become longer, multiplying the swept area and so the amount of wind energy that can be harnessed by each turbine. Continued improvements in wind technologies are on the horizon, with larger turbines and improved operational efficiency expected over a wider range of wind conditions. Rising labour costs in leading markets offset part of these gains. With this effect, the average LCOE from onshore wind is projected to decrease by more than 15% in a number of regions by 2030. In the case of offshore wind, costs are projected to decline by close to 30% to 2030, reflecting its current status as a less mature technology than its onshore counterpart. Some near-shore projects in Germany and Denmark look set to achieve new record low costs for the technology.

As historical and prospective cost declines for renewable energy technologies shine a spotlight on the potential cost-competitiveness of renewables, compared with conventional fossil fuels and nuclear power, the LCOE provides one basis for comparison across technologies. However, this measure is only a first approximation of competitiveness. The value of electricity provided by each technology must also be considered. Our analysis has indicated that the average value of a unit of output can vary widely across technologies, evolving over time depending on the overall power mix in a market, fuel prices and the scarcity of electricity supply (IEA, 2016b). The additional system costs entailed in the integration of new sources, including the necessary extension of, or strengthening of, grid infrastructure that is specific to each system and project, must also be taken into account in order to form a clear picture of competitiveness.

Value considerations are especially important when comparing technologies that have different operational characteristics and provide different services to the grid. Among conventional power plants, peaking plants are designed to respond quickly and deliver power when it is needed most, so achieving higher value per unit of output than baseload technologies that are designed to provide stable output most of the time. Peaking plants can, accordingly, have notably higher levelised costs than baseload technologies, yet still be competitive. Another important distinction is between variable renewables – whose production is tightly linked to the availability of a variable source of energy (e.g. wind or solar insolation) – and dispatchable technologies that are able to match their level of production to demand. The value of variable renewables can decline substantially as they represent increasing shares of total generation, as their output coincides less precisely with system needs (Hirth, 2016). This concept of declining value applies equally in liberalised wholesale electricity markets and fully regulated ones, though the issue may be less obvious in regulated markets that do not have continuous price signals.

In the New Policies Scenario, the average LCOE from new onshore wind power and solar PV falls below that of new coal- and gas-fired power plants in many regions, indicating that they are competitive in cases where they offer comparable value to the alternatives and do not add significant costs to the overall power system. Compared with new gas-fired CCGTs, the average LCOE from onshore wind power projects is already lower in China and India, and is projected to become so by 2025 in the European Union and by 2030 in the United States.[13] The levelised cost of output from solar PV is already cheaper than that from new CCGTs in India, it becomes cheaper by 2020 in China, but it is expected to take longer for the average LCOE to match that of a new CCGT in the United States and European Union. For the purposes of comparison, the same weighted average cost of capital (WACC) is assumed across technologies within each region. Given the capital-intensive nature of wind and solar PV technologies, the availability of low-cost financing can significantly reduce the LCOE (more so than for coal- and gas-fired power plants), making them more cost-competitive with gas-fired power plants and other technologies (Figure 6.21).

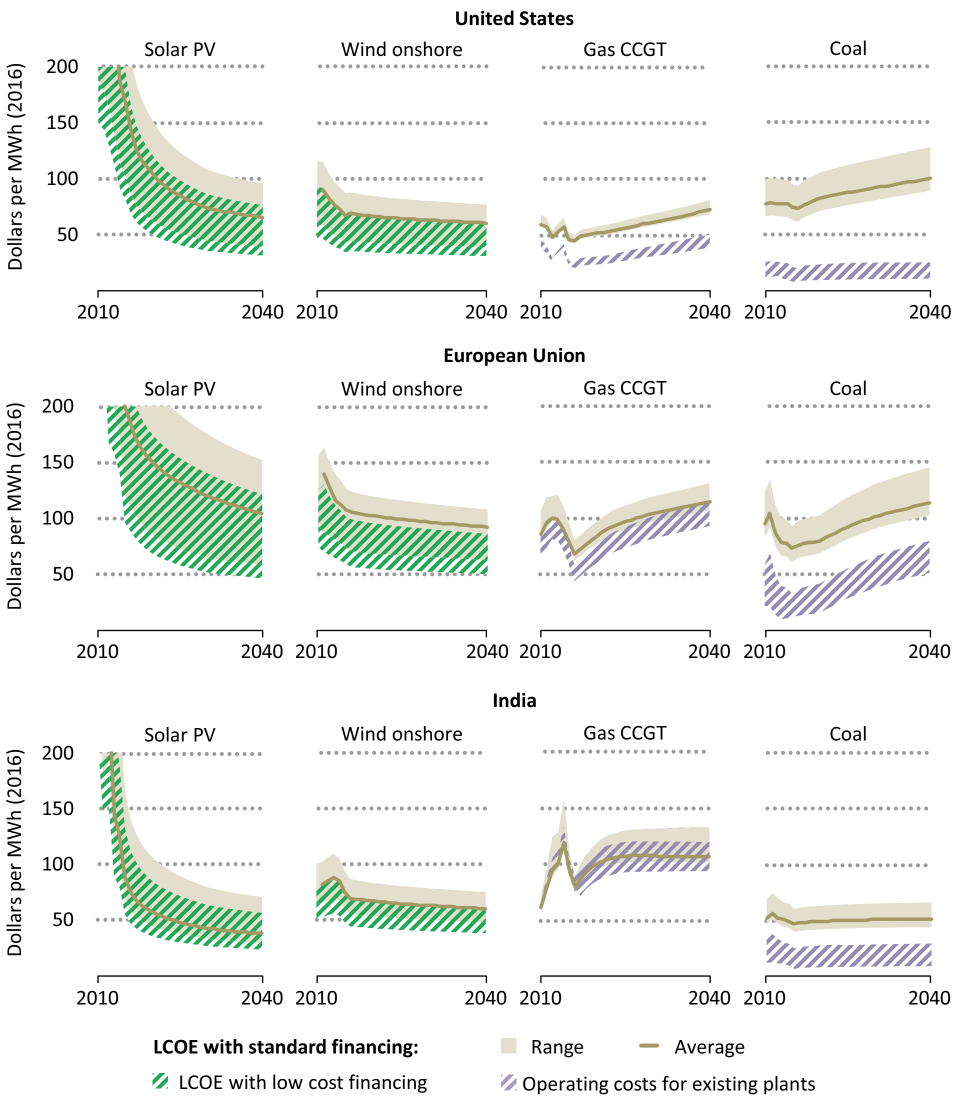
The LCOE from new coal-fired power plants is lower than that from new gas CCGTs in most regions, making their cost competition more challenging for renewables. Compared with the cost of power from new subcritical and supercritical coal-fired power plants, wind power is already cheaper in the United States and reaches similar cost levels by 2030 in the European Union and China. Assuming the same WACC, the average solar PV project becomes cheaper than coal by 2025 in India, by 2030 in China and the United States, and by 2040 in the European Union, though low cost projects achieve cost parity earlier.

In addition to competing against new plants, new renewable energy technologies may have to compete with existing conventional power plants, making the comparison with their operating costs important too. Particularly in advanced economies, the fleet of power plants currently in operation would be able to meet most electricity demand for years to come. To take one example, the operating costs of existing coal-fired power plants are generally below $30/MWh, meaning that coal remains very competitive against any competing technology, in the absence of a significant carbon price. Where natural gas prices are low, such as in the United States, Middle East or Russia, existing gas-fired power plants can also be cheap to operate. However, gas prices are notably higher in regions that rely on imported gas, making renewables more attractive compared with existing gas-fired power plants in the near term in China and India, and in the 2030s in the European Union.

Competition between fossil fuels becomes fiercer over time in the New Policies Scenario, as the potential market for fossil fuels falls from two-thirds of global electricity generation to half by 2040. Competition between fossil-fuelled power plants tends to favour coal-fired power plants, except where significant carbon prices apply. As natural gas prices are set to increase in all markets in the New Policies Scenario, so the CO_2 price necessary to offset the cost advantage of coal rises. For example, a CO_2 price in the range of $50-100 per tonne of CO_2 is needed to equalise the operating costs of coal- and gas-fired power plants in 2025 in the European Union. In China, the carbon price needed in 2025 is notably higher, over $90/t$CO_2$, since gas prices are higher and most coal plants employ highly efficient ultra- supercritical technology. The cases of the United States and Russia are exceptions. The availability of

13. To aid technology comparisons, a common WACC is assumed for all technologies in each region: in real terms, 8% in OECD countries and 7% in non-OECD countries.

Figure 6.21 ▷ Historical and projected levelised costs of electricity by selected technology in the New Policies Scenario



The falling costs of solar PV and wind improve their competitiveness against new gas- and coal-fired power plants in the near term

Notes: Coal refers to subcritical and supercritical designs. CCGT = combined-cycle gas turbines. LCOE = levelised cost of electricity. Operating costs include the costs of fuel, variable operation and maintenance and CO_2 (where priced). Historical capital costs and capacity factors for solar PV and wind provided by the International Renewable Energy Agency. LCOEs for gas CCGTs and coal are based on projected fuel prices for a range of capacity factors (50-80%). Standard financing applies a WACC of 8% in real terms in the United States and European Union, and 7% in real terms in India. Low-cost financing reduces the cost of capital by three percentage points.

very low priced gas (below \$3/MBtu) has helped gas-fired power plants to out-compete coal plants in the short term and contributed to the retirement of older, less efficient, coal plants. Thus gas overtook coal as the leading generation source in the United States in 2016, and some coal plant retirements were accelerated, shifting the long-term balance in the process. Nonetheless, coal remains an important part of the power mix in the United States, and is projected to provide about one-quarter of total generation through to 2040.

The costs of batteries have also fallen substantially in recent years, catching the attention of the industry and giving rise to new consideration of potential utility-scale applications of battery storage and their economics, including as a means of replacing peaking power plants (Box 6.2). We project total battery system costs to decline by about two-thirds by 2040, from about \$700/kWh of storage capacity in 2016 to less than \$300/kWh, with the balance of system costs making up close to three-quarters of the total installation costs for stationary battery storage systems.[14] Batteries are also garnering attention for individual businesses and consumers. When paired with solar PV, storage can help consumers use more of the electricity that they generate, which may improve the economics of their system. Energy storage at the site of consumption can also increase the reliability of electricity supply, by providing a source of backup if there is an outage on the network. For off-grid and mini-grid systems, energy storage is essential to improving the quality of electricity services provided by variable renewables, including solar PV and wind power.

Box 6.2 ▷ Will utility-scale batteries replace peaking power plants?

In recent years, the momentum behind battery storage – and lithium-ion batteries in particular – has increased significantly. With greater deployment of EVs and wider use of battery storage at both utility- and the consumer-scale, the cost of batteries has fallen significantly and is expected to decrease further.

The nature of a battery differentiates it from a typical generator in that it can both inject energy into and withdraw energy from the grid (as do other storage technologies, such as pumped hydropower), and can alter its output or consumption more rapidly than most other technologies. This allows batteries to provide a variety of services to different customers and earn revenues from different markets. In order to maximise the revenue potential of batteries, they must optimise their performance so as to accrue revenue from multiple services, known as revenue stacking. Possible revenue streams for batteries can come from ancillary markets (including frequency control and reserves), capacity markets, energy markets (energy arbitrage) and grid services (including voltage control and T&D investment deferrals). Batteries may also be coupled with renewable energy projects in order to increase their value by reducing the variability of their output.

14. Indicative costs are for a lithium-ion battery and balance of system for utility-scale applications, with four hours of storage per unit of output. Analysis suggests that this level of storage provides for capturing the full capacity value (ICF, 2016).

However, storage is a clear example of how market design must become more sophisticated if the further deployment of new energy technologies is to be encouraged. As battery costs decline, they become increasingly competitive against other peaking technologies (as well as other forms of flexibility, including demand-side response), such as gas-fired open-cycle gas turbines (GTs); but it will be challenging for them to compete on the basis of revenues from energy sales alone. As of 2016, the total costs of utility-scale batteries were about $700/kWh,[15] notably more than the cost of the battery pack alone, as a significant portion is related to the balance of system components. Considering a case in which battery costs are halved by 2030 in the New Policies Scenario, the competitiveness of batteries with gas GTs still relies on their ability to earn relatively high revenues in non-energy markets. Making use of the World Energy Model, simulated hourly electricity prices enabled estimations of revenue opportunities for storage in energy-only markets, making it possible to estimate the non-energy revenues needed to enable storage to compete with other peaking technologies. For example, low gas prices in the United States make competitiveness with gas GTs elusive; we estimate that, in addition to energy sales, battery systems require three- to four-times the amount of non-energy revenues (Figure 6.22). The business case is less challenging in the European Union, where gas prices are notably higher, but utility-scale batteries still require a multiple of the non-energy revenues of a gas GT. In order to compete directly with gas GTs on the basis of energy revenues alone, the costs of battery systems would need to fall from current levels by more than three-quarters by 2030 both in the United States and European Union.

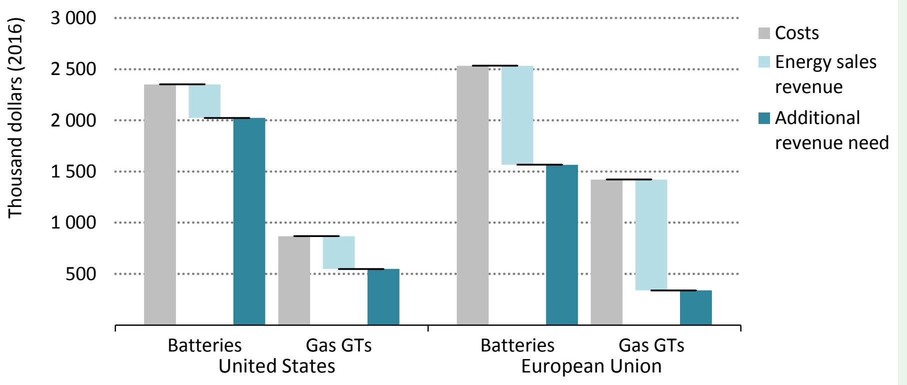
At present, batteries can be competitive in some markets to provide ancillary services, particularly frequency control, as their ability to respond quickly to frequency changes makes them well suited to following rapid fluctuations of demand. In the United States, almost all third-party owned energy storage systems (not owned either directly by utilities or customers) in 2015 were deployed in the Pennsylvania-New Jersey-Maryland Interconnection (PJM) market, where market reforms allow batteries to earn a premium for their performance in frequency control (Hart and Sarkissian, 2016). Most other markets have not yet implemented similar reforms to recognise the value of differences in performance in this respect. The value of battery storage in the United States varies widely across the country, depending on the specific market's structure and price volatility in the market (Fitzgerald et al., 2015).

In the United Kingdom, the National Grid called an auction in 2016 to procure 201 MW of fast responding services, which were fully met by energy storage providers. However, as the ancillary market is, typically, only a small fraction of the overall wholesale market (for example, PJM typically procures less than 1% of peak demand in the frequency control market), the margins in ancillary markets are depressed if there is an abundant

15. Based on the midpoint of estimated costs for "peaker replacement" lithium-ion batteries in Lazard (2016).

supply of battery storage. Hence, over the longer term, as energy storage deployments pick up, batteries would need to compete increasingly in energy markets. The potential expansion of capacity markets would also expand the opportunities for battery storage.

Figure 6.22 ▷ Indicative annual costs and revenue needs for batteries and gas GTs in the United States and European Union, 2030



Even though battery storage increases its competitiveness, it still needs to rely on payments outside the energy market to recover the investment

Notes: Gas GTs = gas-fired open-cycle gas turbines. Estimates based on 10 MW/40 MWh battery storage system, with installed costs of $400/kWh, and 10 MW gas GT power plant, with a capital cost of $540/kW. For comparison, the annual output for both technologies is equal.

6.3.8 Support for renewables-based electricity

Based on a survey of established national level policies and on the known deployment of new renewable energy projects in 2016, we estimate that global subsidies provided to renewable-based electricity were $140 billion, about 20% higher than in 2015.[16] The year-on-year increase was driven by the growth in the deployment of wind and solar PV technologies, with nearly three-quarters of the growth coming in China, Japan and the United States. While the costs of renewables continued to fall in 2016, it was also a year in which natural gas prices were very low in some markets, reducing wholesale electricity prices. One result was that the increase in subsidies for renewables (reflecting the form of past renewable support mechanisms) outpaced the growth in generation from non-hydro renewables, which increased by 14% in 2016. Overall, wind power and solar PV dominate non-hydro renewables output and are the primary recipients of subsidies for renewables, accruing 80% of the total. Bioenergy-based power plants are the third-most supported renewable energy technology, receiving an estimated $22 billion in 2016.

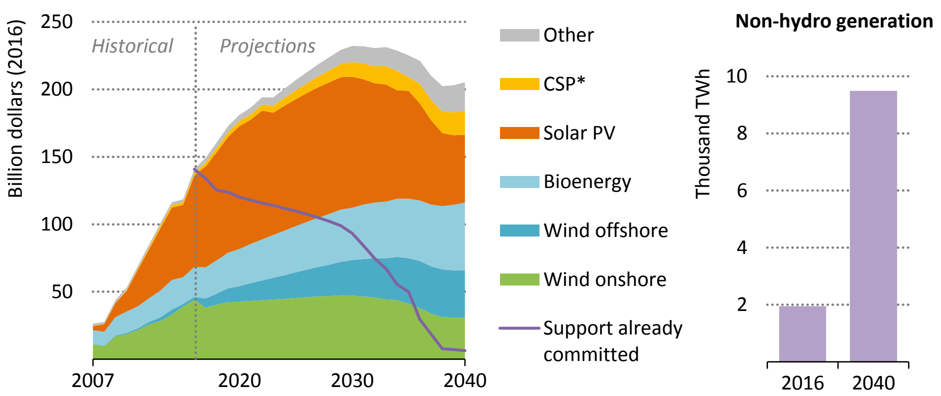
16. For the historical estimates, the financial value of the support is calculated as the difference between the feed-in tariff, market premiums, green certificate or any other form of financial support, and the wholesale electricity price in each region, which is then multiplied by the amount of generation for each renewable technology.

While the deployment of renewables is increasingly widespread, support for renewables remains concentrated in a small number of countries. As early adopters and the leading developers of the technologies, the top-five supporters of renewables – Germany, United States, China, Japan and Italy – provided nearly two-thirds of the total financial support in 2016. Within four of these five countries, solar PV is the largest recipient of support. The exception is China, where wind power receives more support. Overall, the European Union accounts for almost 45% of global support for renewables in 2016, as France, Spain and the United Kingdom also provided substantial support.

In the New Policies Scenario, subsidies to renewables-based electricity increase by two-thirds to 2030, while generation from non-hydro renewables triples, before falling back to about $200 billion per year by 2040, as current long-term support commitments expire (Figure 6.23).[17] Of the cumulative subsidies provided over the period to 2040, about 70% supports solar PV and wind power (over one-third of which is provided to offshore wind projects) and around 20% to bioenergy. Other types of renewables, including CSP, tidal and wave, and geothermal, are deployed to lesser extents and receive less support. Of the total support paid to renewables over the *Outlook* period (almost $5 trillion), about 40% is already committed to existing projects.

6

Figure 6.23 ▷ Renewables-based electricity support and cumulative total generation in the New Policies Scenario



Global subsidies to renewables increase from $140 billion today to $200 billion in 2040, while non-hydro generation more than quadruples

*CSP = concentrating solar power.

17. For the projected subsidies, the financial value of the support is calculated as the difference between the levelised cost of electricity for new renewables-based technologies and the wholesale electricity price in each region, which is then multiplied by the amount of generation for each renewables-based technology. For variable renewables, as their share of the mix rises, their declining value is estimated and reflected in the price received. For more information, see *www.iea.org/weo/weomodel/*.

With deployment of renewables spreading around the world, support for renewables becomes more widespread. The European Union remains the leading supporter of renewables, but supplies less than one-third of the total support by 2040. The expansion of renewables in China and India helps to drive down the average costs of solar PV and wind power domestically and globally, moderating the required growth in support over time. Together, China and India account for about one-quarter of total support in 2040, while accounting for over 40% of global generation from non-hydro renewables. Combined, Southeast Asia, Africa, Latin America and the Middle East are projected to provide about $33 billion of support per year by 2040.

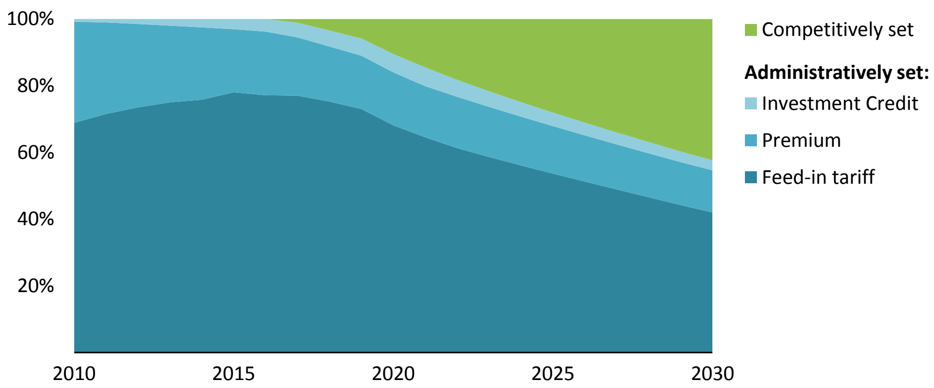
The subsidy paid per unit of electricity generated decreases dramatically over time as a result of technology cost reductions and rising wholesale electricity prices in most regions. The global average subsidy per unit of output for new solar PV projects declines by about two-thirds by 2030, while those to wind power fall by 40%. The unit subsidy for new solar PV projects decreases by three-quarters to 2030 in the United States, about two-thirds in China and by over half in Japan and the European Union, while solar PV in India requires no support (e.g. preferential financing or land allocation) for new projects built after 2030. Similarly, the unit subsidy for wind power decreases strongly over time in the biggest markets, dropping by half in the European Union and Japan, and approaching zero for all new projects in China, India and the United States by 2030.

There are many types of mechanisms that have been used to date to support the deployment of renewable energy projects, including feed-in tariffs (FiTs), market premiums, green certificates and investment tax credits. FiTs provide a guaranteed fixed price for output, while market premiums and green certificates provide revenue streams that are additional to market-based revenues. The level of support provided by green certificates depends on the market price at which they are traded in competitive markets, while the level of remuneration provided by a FiT and market premium can be decided and set administratively by a central authority or discovered through auction mechanisms. Auction schemes determine competitively the level of support for winning projects, setting either the level of a premium or FiT. An investment credit provides a one-time fiscal credit, typically once the construction of the renewable energy project is completed, reducing the overall cost of the project for the developer.

As of 2016, about three-quarters of worldwide generation from wind and solar PV was supported through FiTs. Premium mechanisms are the second most important form of support to wind and solar PV today (20% of the total), having supported wind power in the United States over the past two decades through the production tax credit. The next largest form of support is investment tax credits (5%), which mainly support solar PV in the United States. Auction schemes are in use in 70 countries and at least 34 countries conducted new auctions in 2016. Aside from commissioned projects in Brazil and South Africa, the majority of projects procured under these arrangements are yet to come online.

The preferred policy approach to support the deployment of renewables is undergoing a transition. Deployment under mechanisms that competitively determine levels of support (green certificates and auction-based premiums and FiTs) is set to proliferate in the near term (IEA, 2017e). By 2030, these mechanisms are projected to support more than 40% of global wind and solar PV generation (Figure 6.24). In addition to the many auctions, the establishment of a green certificate programme in China would add significantly to the scale of projects procured under competitive means. Harnessing competitive forces is expected to further drive down technology costs, helping close to 20% of all wind and solar PV generation subsidy-free by 2030. Despite the rapid transition to competitive mechanisms, FiTs will continue to support a significant proportion of output from wind and solar PV for years to come, as long-term commitments are fulfilled.

Figure 6.24 ▷ Share of supported wind and solar PV generation by mechanism type in the New Policies Scenario



Taking over from feed-in tariffs, mechanisms with competitively set levels of support, such as auctions, become the primary frameworks for developing renewables

Box 6.3 ▷ Offshore wind and bidding zero

Auction schemes for renewable energy are increasingly popular around the world, awarding contracts to developers who bid the lowest price for electricity delivered from new projects. In April 2017, Germany's electricity grid regulator awarded power purchase agreements for 1.5 GW of new offshore wind projects at the incredibly low market premium price of $5/MWh on average, on top of the wholesale market price. In fact, three-out-of-four projects bid at a zero market premium, surprising the industry and onlookers, as, at the first glance, those projects do not require subsidies and rely only on the wholesale market as the source of revenue.

Bidding zero does not mean that the average cost of the electricity produced is zero. Instead, a strike price of zero indicates that the developer is not reliant on a guaranteed price for delivered electricity from the counterparty, the Germany's electricity grid operator in this case. In other words, the project developers are content to take whatever price prevails in the market at the time of delivery. Developers may look to financial instruments to hedge their revenue risk.

The bids were particularly noteworthy because they were for offshore wind, a renewable energy technology that has been relatively expensive to date, compared with onshore wind. For projects completed in 2016 in Europe, the estimated average LCOE from onshore wind was about $100/MWh,[18] more than 40% lower than that of recent offshore wind projects. However, the LCOE from offshore wind projects has been declining in recent years, and significant performance gains and LCOE reductions are expected as the scale of individual wind turbines continues to increase. Single turbines with rated capacities above 10 MW are expected soon, and their enhanced performance is expected to play an important role in the projects that are slated to come online in 2024 and 2025. Relatively low penalties for abandoning the projects, as late as 2023, also encouraged very aggressive bidding. In practice, developers have several years before they need to opt to develop these projects, which will eventually depend on the technology and market conditions in the early 2020s.

In the absence of other forms of support, bids with a strike price of zero would signal that a technology is fully competitive. However, this milestone may not have been achieved just yet, as the auction scheme in Germany fully subsidises the grid connection costs for the projects, which have been in the range of $10-20/MWh for recent projects.[19] These costs are ultimately paid by end-users through network charges.

It is not yet clear what the zero strike price bids herald, but offshore wind does appear to be gathering momentum. The outcome of the bids suggests that the design of auction schemes may need some further adjustment to improve transparency for policy-makers and consumers. What is clear is that harnessing the competitive forces of auctions are driving strong technology cost reductions.

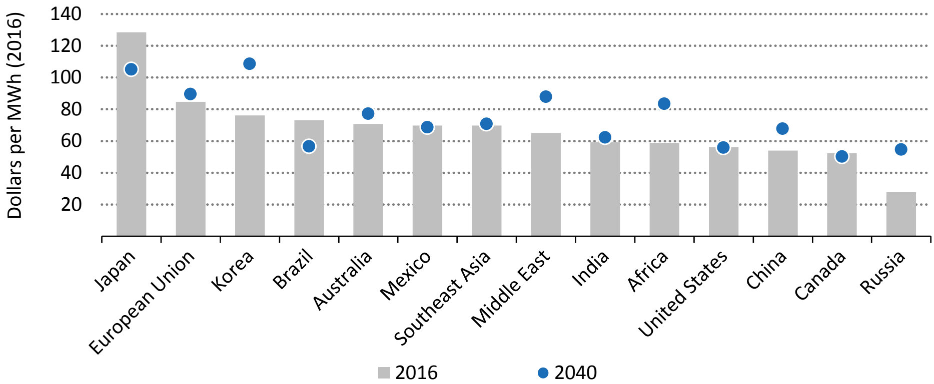
6.3.9 Power generation costs and electricity prices

Power generation costs reflect the historical costs of the existing power plant fleet, plus new costs to meet growing demand, replace or refurbish old plant and, increasingly, costs associated with carbon pricing in support of decarbonising the power mix. Generation costs are a key component of electricity prices; and indeed, prices must provide the full recovery of costs in the long term. Globally, we estimate that power generation costs were $64/MWh in 2016, accounting for past investments, including those which have already recovered their initial capital investment, and operating costs. In the New Policies Scenario, global average power generation costs increase by about 10%, to $70/MWh in 2040.

18. Estimate based on a 20-year economic lifetime and 8% WACC.

19. *https://ore.catapult.org.uk/wp-content/uploads/2016/05/Transmission-Costs-for-Offshore-Wind.pdf.*

Figure 6.25 ▷ Average power generation costs by region in the New Policies Scenario



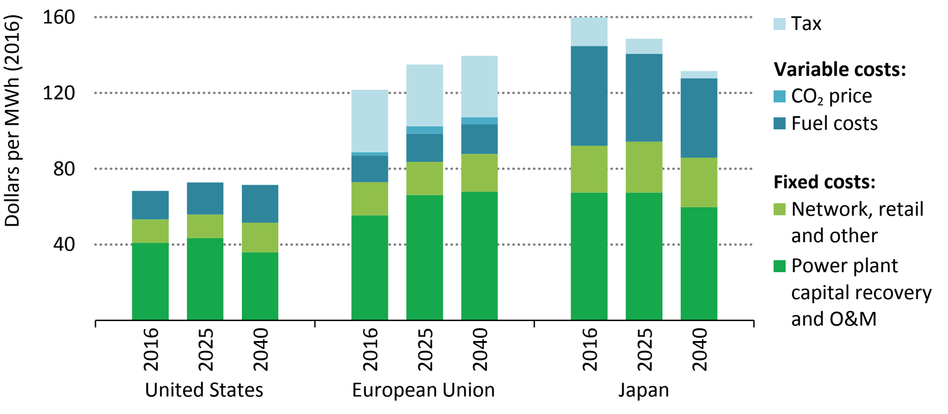
Average power generation costs are $50-80/MWh in most regions today, and most increase over time in the New Policies Scenario

Average power generation costs vary substantially across regions, as the mix of technologies present, the investment costs for those technologies, plant designs and efficiencies, and fuel prices all vary by region. In most regions, average power generation costs are $50-80/MWh, with a few exceptions above and below this range (Figure 6.21). The United States, China, Canada and Russia are at the lower end of the range, as they are able to tap large inexpensive sources of domestically sourced energy for use in electricity generation. On the other extreme, Japan, the European Union and Korea have high average power generation costs, in part because they rely on imported fuels. Over time, power generation costs are set to increase in most regions. They increase most significantly in Korea, the Middle East and Africa, three regions that look heavily to gas as a primary source of electricity, whose price is set to increase substantially in most markets. On the other hand, average power generation costs are set to decline in Japan and Brazil, as they recover from challenging conditions and reduce their need for imported fuels. In Japan, this is thanks to the gradual re-introduction of nuclear power and rising shares of renewables, while, in Brazil, hydropower is assumed to return to typical operations following the recent multi-year drought.

Power generation costs consist of both fixed costs and those that vary with the amount of electricity generated within a year. Fixed costs include the recovery of past capital investments in power plants and network infrastructure, fixed operational and maintenance costs, including the costs of refurbishment, retail and other costs associated with conducting the electricity business. Variable costs include fuel costs per unit of output (that can be high for gas-fired power plants or very low for nuclear and most renewable technologies), carbon costs (that are becoming more widespread across regions) and taxes. Fixed costs make up more than half of the total costs of electricity supply in most markets, though electricity tariffs generally have larger variable portions. This has important implications on the long-term financial health of the power sector, as appropriate tariff designs support recovery of past capital investments, particularly with smaller players playing a larger role in electricity supply and self-consumption increasing.

Electricity prices can be an important factor of competitiveness in electricity-intensive industries, though not all types of industries pay the average rate. The United States enjoys relatively low average industrial prices today (Figure 6.26). Over the period to 2040 in the New Policies Scenario, prices in the United States remain relatively stable, backed by persistently low natural gas prices. This latter point, plus a large mobile skilled labour force and cheap land in some regions, make the United States an attractive location for some energy-intensive industries. By contrast, the European Union and Japan have relatively high electricity prices, driven by high fuel costs, taxes or other costs. Over time, industrial electricity prices in Japan are projected to decline substantially due to reduced fuel and capital recovery costs, as the recent surge of investment in solar PV slows. At the same time, prices in the European Union are set to rise, in part due to assumed market reforms that enhance capital recovery, and be among the highest globally. Energy-intensive industries will face competitive challenges where they are not exempted from elements of the electricity price.

Figure 6.26 ▷ Average industry electricity prices by region and cost component in the New Policies Scenario

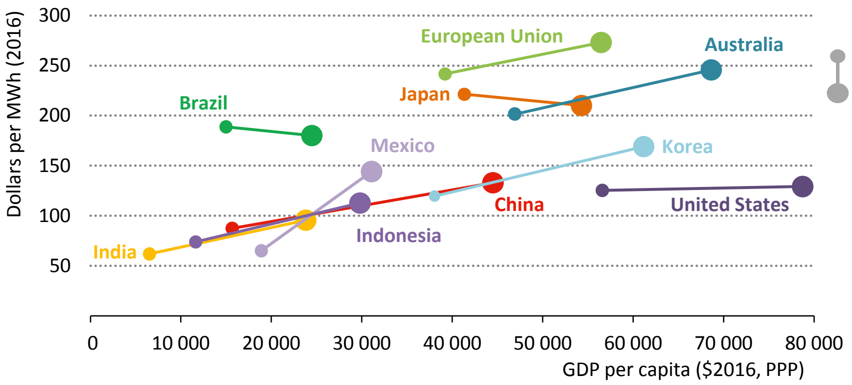


Electricity prices to industry vary widely across regions, and fixed costs generally account for more than half of total costs

Note: O&M = operation and maintenance.

Electricity prices to residential end-users increase in almost all regions in the New Policies Scenario (Figure 6.27), in part due to increasing power generation costs, but government policy also plays an important role. On the one hand, taxes on electricity add significantly to end-user prices in many regions, most notably in the European Union. On the other hand, there are subsidies for electricity in many countries, including in the Middle East, Indonesia, China, India and Mexico. In the New Policies Scenario, based on announced policies, the subsidies to electricity consumed in households are completely phased out by 2025 in China, India and Indonesia, and are reduced in most other regions. The United States is an exception to both rules, with essentially no taxes or subsidies specific to households on electricity prices. Despite the general increase, electricity prices and household expenditures tend to increase more slowly than GDP per capita, indicating that electricity generally becomes more affordable over time.

Figure 6.27 ▷ Average household electricity prices by region in the New Policies Scenario



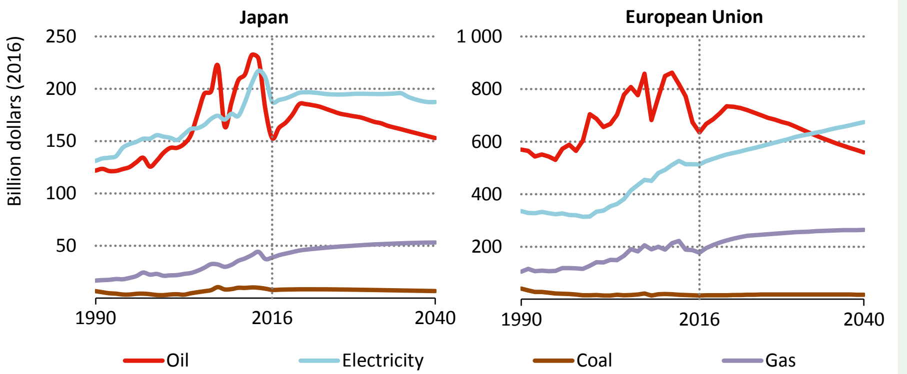
Residential electricity prices increase in almost all regions, reflecting rising power generation costs, tax policy and subsidy reform

Box 6.4 ▷ The rise of electricity in end-user energy expenditure

As a result of oil's prominent position in the global energy landscape, end-user expenditure on energy has historically been dominated by spending on oil products. However, as the electrification of energy demand continues and efforts to reduce CO_2 emissions intensify, electricity will challenge oil as the principal source of end-user expenditure on energy. In 2016, global expenditures on electricity approached $2.4 trillion, narrowing the gap with expenditure on oil products to unprecedented levels. Despite projected increases in oil prices, electricity remains or becomes the largest element in end-use energy expenditure in some regions.

Spending on electricity already exceeds expenditure on oil products in Japan and China (see Spotlight in Chapter 12). In Japan, due to high electricity prices and the dominant role of electricity in industry, electricity expenditure first exceeded oil expenditure in the mid-1980s. The Fukushima Daiichi accident and subsequent increases in electricity prices increased the importance of electricity bills, relative to end-user energy expenditure on oil products. Through 2040, growing demand for electricity from ICT and small appliance loads and the electrification of transport, sustain electricity expenditure at the current level despite declines in prices (Figure 6.28).

Figure 6.28 ▷ End-user energy expenditure in the New Policies Scenario



Continuing electrification drives electricity demand growth, while oil is substituted by cleaner fuels in many sectors

End-user spending on electricity in the European Union is expected to exceed spending on oil products by 2033. Greater electrification is the main driver of this trend. Accelerating adoption of heat pumps and increasing demand from ICT and small appliance loads sees electricity demand in buildings increase at nearly 0.5% annually, while oil demand in buildings falls by over 7% annually. Changes in the transport sector also contribute to electricity expenditure overtaking oil. In the European Union, electricity use for road transport increases by over 18% annually, while oil demand decreases, driving down passenger car spending on oil products in 2040 to around 60% of today's level.

Energy efficiency and renewable energy

Stairway to decarbonisation?

Highlights

- Global energy intensity falls by 2.3% per year to 2040 in the New Policies Scenario. Without expected improvements in energy efficiency, the projected rise in global final energy consumption would more than double. Savings are largest for oil, with fuel-economy standards, rather than electric vehicles, being the most important factor that leads oil demand from passenger vehicles to peak by the mid-2020s.

- Renewable energy sources supply more than 40% of the incremental primary energy demand to 2040 in the New Policies Scenario, more than any other fuel. Electricity generation from renewables overtakes that from coal in the 2020s to supply 40% of electricity by 2040. Growth is not confined to the power sector; the direct use of renewables for heat and transport doubles to 2040. China remains the world leader in renewable energy use, followed by the United States, the European Union and India.

- Investments in energy efficiency and renewables bring multiple benefits in addition to the reduction in GHG and local pollutant emissions. For example, in the New Policies Scenario, the contribution of efficiency measures and renewables to the United States becoming a net fossil-fuel exporter is nearly two-and-a-half times larger than the increase in domestic production of fossil fuels.

- In the Sustainable Development Scenario, co-ordinated deployment of energy efficiency and renewables is the key to an early peak in energy-related CO_2 emissions and their subsequent decline; each account for around 40% of emissions reductions relative to the New Policies Scenario. By 2030, wind and solar combined become the largest source of electricity generation worldwide; their integration in power systems is aided by efficiency policies targeting inflexible electricity demand (such as certain industrial processes) and by switching to more efficient and flexible end-use devices, such as electric vehicles and heat pumps.

- Energy needs in fast-growing parts of the energy system can be met at lower cost if renewables and efficiency measures are used together. As a result of an integrated approach, the cost of providing low-temperature heat to industrial facilities in India is $15 billion lower by 2040 in the Sustainable Development Scenario relative to the New Policies Scenario.

- However, care is needed to avoid sub-optimal outcomes. For example, there are already some signs that the results achieved through stringent tightening of building codes could have been achieved more cheaply, in terms of total system costs, by wider use of heat pumps powered by renewables-based electricity, or direct renewable heat, such as solar thermal and bioenergy.

7.1 Introduction

Improved energy efficiency and renewable energy supply are complementary approaches to optimising the security and cost efficiency of the energy system, while reducing emissions of local pollutants and greenhouse gases (GHG) and facilitating wider access to energy, so reducing energy poverty. Energy efficiency and renewables are the backbone of countries' Nationally Determined Contributions under the Paris Agreement on climate change (which are integrated into the New Policies Scenario), reflecting the rapid progress that has been made in performance and costs in these two areas.

Despite widespread recognition of the importance of both energy efficiency and renewables, (e.g. in the UN Sustainable Development Goal for Affordable and Clean Energy [see Chapter 3]), governments have generally supported them using separate policy instruments. As the scale and pace of their deployment grow, the case for an integrated approach to their promotion in a system-wide approach becomes more compelling. There are specific benefits to co-ordination of renewables and efficiency policies in particular. Without an integrated approach, investments may be allocated sub-optimally and consumers may receive conflicting advice about their energy choices. The persistence in some countries of fossil-fuel subsidies is a drag on both energy efficiency and renewables, and an example of conflicting policy priorities.

For the first time, this edition of the *World Energy Outlook* (*WEO*) presents energy efficiency and renewables together in the same chapter. First it reports on recent key trends in energy efficiency and renewables and the outlook to 2040, with regional and sectoral analysis focussing on the New Policies Scenario, the central scenario of this *Outlook.* It then examines the implications of the joint deployment of energy efficiency and renewables. The chapter concludes by highlighting some key areas in which the synergies between the two can be most profitably exploited. Three illustrative cases are presented i) how targeted efficiency policies can help greater integration of variable renewables in the power mix through demand-side response; ii) how to combine renewables and energy efficiency to meet industrial heat demand; iii) how best to incorporate energy efficiency and renewables targets into new buildings energy codes.

7.2 Energy efficiency

7.2.1 Current status

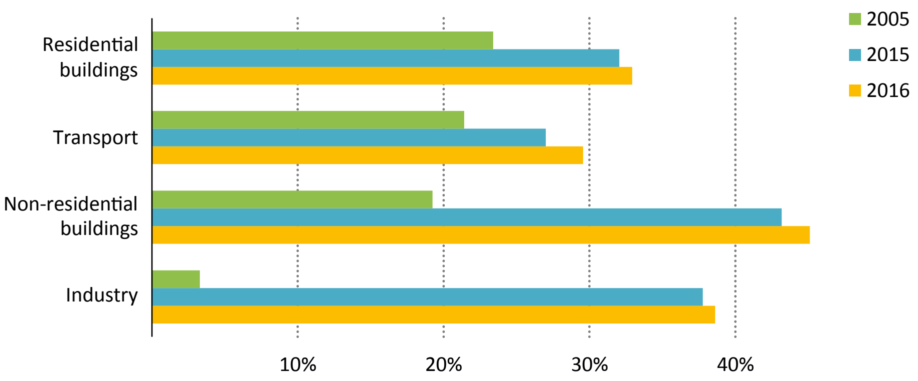
In 2016, global energy intensity, the ratio of primary energy supply to gross domestic product (GDP), continued to fall (by 2.0%), to 115 tonnes of oil equivalent (toe) per $1 million of GDP.[1] Despite persistently low international energy prices and global GDP growth at 3% in 2016, global primary energy demand grew by just 0.9%. However, compared with 2015 (2.8% reduction), progress towards reducing energy intensity has slowed, indicating a need

1. In the *WEO-2017*, energy intensity is calculated using GDP in purchasing power parity (PPP) terms to enable differences in price levels among countries to be taken into account. In our scenarios, PPP factors are adjusted as emerging countries become richer.

for renewed efforts. The worldwide trend conceals considerable regional variations. In China, energy intensity in 2016 was 5.7% lower than in 2015. Despite sustained economic growth (though at two-thirds the pace observed in the 2000s), in 2016 energy demand in China grew at a rate more than ten-times lower than during the 2000s (see Chapter 12). In the United States, energy intensity improved by 3% in 2016, above the global average but lower than the 3.8% improvement in 2015 as a result, in part, of lower oil prices that encouraged higher gasoline consumption. The Middle East is one of the few regions in which energy intensity fell further in 2016 than in 2015.

Much of the reduction in energy demand arising from energy efficiency has been achieved through government policies and measures, including mandatory energy efficiency regulations (such as minimum performance standards, fuel-economy standards, building energy codes, industry targets), public financing and the use of market-based instruments, including tradeable certificates linked to energy saving obligations on utilities. Efficiency improvements are also delivered by price effects, technological change and advances in energy management in the industrial and buildings sectors.

Figure 7.1 ▻ Share of global final energy consumption covered by mandatory efficiency regulations by sector



Over 68% of global final energy consumption remained uncovered by mandatory efficiency codes and standards in 2016

Note: Total final energy consumption also includes agriculture and non-energy use, such as industrial feedstocks.
Source: IEA, (2017a).

Mandatory energy efficiency regulations covered 31.5% of final energy consumption worldwide in 2016, up from 30% in 2015 and 14% in 2005 (Figure 7.1).[2] However, almost all of this expansion was attributable to new and replacement energy-consuming goods

2. This means that over 68% of the world's final energy consumption is by equipment that was not covered by a minimum energy performance standard, or equivalent, at the time of its purchase.

covered by regulations that were in place in 2015, rather than the introduction of more stringent standards, or standards for new categories of goods. In fact, only 1% of the extension in coverage in 2016 was due to policies introduced that year, a level that has been up to 33% in previous years (IEA, 2017a). This indicates a slowdown in the introduction of new energy efficiency regulations around the world, compared to the rapid growth between 2005 and 2015, which was driven largely by the stepwise extension of standards into additional market segments in the European Union and, especially, in China.

Table 7.1 ▷ Selected energy efficiency policies announced or introduced since mid-2016

Country	Sector	New policy measure
Brazil	Lighting	Incandescent bulbs were banned from June 2016. A law for the mandatory efficiency certification of public lighting was published, which aims to ensure the maximum efficiency, quality and safety of lighting products.
Canada	General	New building energy codes for 2022 and federal measures to raise energy efficiency in existing buildings published in support of the Pan-Canadian Framework on Clean Growth and Climate Change, which relies heavily on efficiency for emissions cuts.
	General	Energy performance standards for 20 product categories (including lighting, appliances, water heaters, chillers, electric motors) strengthened in December 2016.
China	General	Leading Efficiency Programme (LEP), a nationwide energy labelling initiative focused on promoting energy-efficient products, launched in June 2016.
	Transport	Corporate Average Fuel Consumption limit for new cars of 5.0 litres/100 km in 2020, and ambitions for 4.0 litres/100 km by 2025.
European Union	General	Updated Energy Efficiency Directive proposed in November 2016 as part of a package of measures to prioritise energy efficiency in the pursuit of energy policy objectives. EU Council agreed in June 2017 to increase the overall EU energy savings target from at least 27% to 30% in 2030, and to extend beyond 2020 the obligation on energy suppliers to improve energy efficiency by 1.5% per year.
	Buildings	Updated Energy Performance of Buildings Directive proposed in November 2016 to strengthen energy efficiency requirements in buildings.
India	Buildings	New voluntary Building Energy Codes introduced in June 2017 (Box 7.6).
	Transport	Light-duty vehicle CO_2 standards came into effect in April 2017, heavy-duty vehicle fuel-economy targets are to come into effect in 2018.
Indonesia	General	Goal announced to reduce energy consumption by 17% by 2025 compared to business-as-usual, to be achieved through the implementation of economy-wide energy efficiency measures.
Japan	General	Energy Efficiency Technology Strategy for research and development published in September 2016, as part of the Strategic Energy Plan.
	Buildings	Building Energy Efficiency Act, including energy efficiency standards for new large-scale non-residential buildings, entered into force in April 2017.
South Africa	General	Draft National Energy Efficiency Strategy published in December 2016, promoting energy efficiency as the "first fuel" to achieve a 29% reduction in economy-wide final energy consumption by 2030.

The policy developments which have occurred since mid-2016 can be divided into two groups: new policies that were implemented for the first time; and new phases of existing policies. There was a fairly even split between the two categories. The recent suite of measures in Brazil targeting efficient lighting is an example of new policy (Table 7.1). The new passenger vehicle fuel-economy standards in China and India are examples of a more stringent application of existing policies. Renewed efforts were made to reform fossil-fuel subsidies in 2016, especially in the Middle East; for example in December 2016, Saudi Arabia announced the phase-out of fossil-fuel subsidies by 2020.

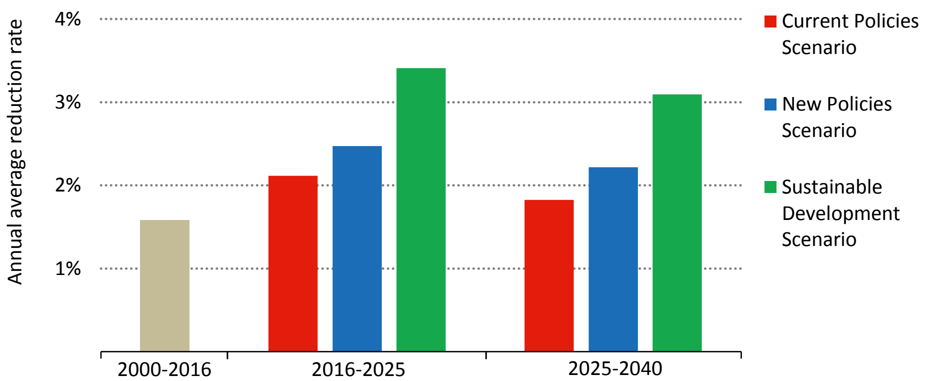
7.2.2 Outlook for energy efficiency

Trends by scenario

Energy efficiency policies are expected to contribute to the further reduction of energy intensity in each of the scenarios discussed in this *World Energy Outlook*. The improvement is more significant in the coming decade and slows after 2025 in all the scenarios (Figure 7.2). Energy intensity decreases by 1.9% per year on average by 2040 in the Current Policies Scenario (compared with 2.3% in the New Policies Scenario), a reduction slightly higher than the average global reduction since 2000 (1.6%). In the Sustainable Development Scenario, energy efficiency has a much bigger impact on energy demand: energy intensity improves at an annual rate of 3.2%, double the rate of the preceding 15 years. The resulting final energy savings in 2040, compared with the New Policies Scenario, are equivalent to around one-eighth of global primary energy consumption today.

7

Figure 7.2 ▷ Global energy intensity reduction by scenario



Energy efficiency boosts the rate of energy intensity reduction

Efficiency measures included in the New Policies Scenario lead to the avoidance of 5% of final energy demand in 2040, compared to the Current Policies Scenario. The saving of more than 650 million tonnes of oil equivalent (Mtoe) is similar to the energy consumption of Russia today. Around two-fifths of these savings come from oil in the transport sector, followed by electricity in the buildings[3] sector (about 15%) and gas in the industry sector (almost 10%).

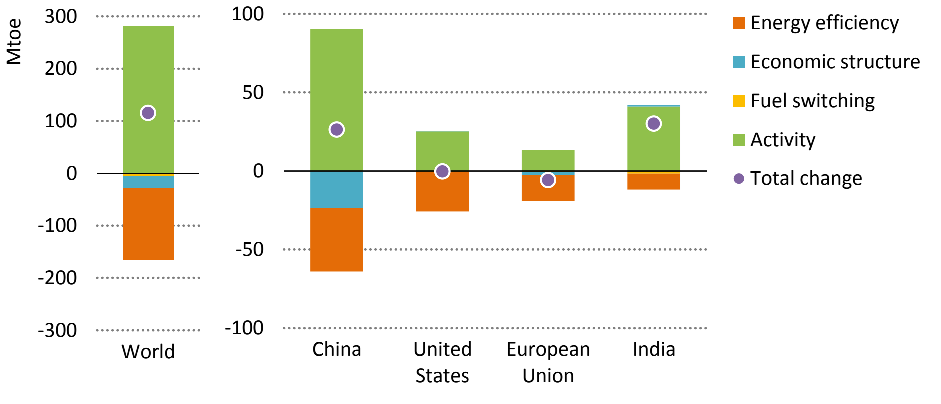
3. The buildings sector includes energy used in residential, commercial and institutional buildings.

The extent of avoided final energy demand[4] in 2040 due to energy efficiency is lower by about 10% in the New Policies Scenario than in the projections of last year's *World Energy Outlook*. One reason is that this year's New Policies Scenario has a lower outlook for oil and gas prices compared to the *WEO-2016* (see Chapter 1), which diminishes the uptake of non-mandated efficiency opportunities. When energy prices fall, the promotion of energy efficiency policies may also weaken. Since oil prices slumped in mid-2014, there has been a slowdown in improvements in the average fuel economy of new light-duty vehicles, especially in the United States.

Trends by region

A number of significant energy efficiency policies currently under development are expected to boost energy intensity reduction in the New Policies Scenario. These include the strengthening of mandatory energy performance regulations in various regions, as well as the implementation of new policy packages announced but not yet implemented, for example in the European Union and China. Taking these developments into account, over the projection period to 2040 primary energy demand grows about 1% per year, which is about half the pace of growth seen in the period 2000 to 2016. To put this in context, an 80% increase in global GDP between 2000 and 2016 was accompanied by a 40% increase in primary energy demand, whereas a similar level of economic growth in the New Policies Scenario by 2040 is accompanied by a 20% increase in primary energy demand.

Figure 7.3 ▷ Average annual change in final energy consumption in selected regions in the New Policies Scenario, 2016-2040



Energy efficiency halts demand growth in advanced economies

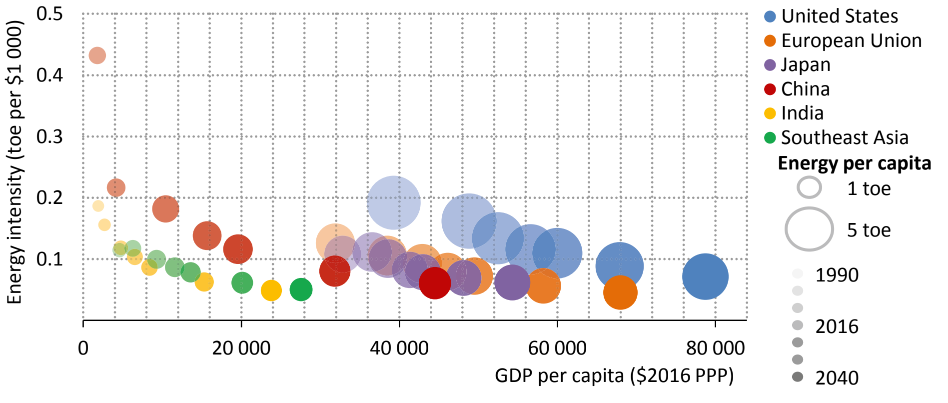
Note: IEA analysis based on decomposition analysis. This statistical approach identifies the relative influence on energy demand of changes in efficiency, fuel switching, economic structure and activity.

4. Avoided final energy represents the additional amount of energy that would have been required in a given year if energy efficiency policies had not been deployed up to the given year in the New Policies Scenario.

While the link between GDP growth and energy demand growth weakens considerably by 2040, increased activity (i.e. more demand for energy services, such as mobility or materials) continues to drive up energy demand in the New Policies Scenario (Figure 7.3). Increased activity in the global economy outweighs the combined impact of energy efficiency progress, fuel switching and shifts in economic structure towards less energy-intensive activities. Improvements in energy efficiency keep final energy demand in both the United States and European Union lower in 2040 than in 2016, despite more economic output. The combination of energy efficiency and structural change in China explains why final energy demand growth there is lower than in India over the *Outlook* period, despite China boosting its GDP, in absolute terms. In India, the shift to a more services-oriented economy is offset by a higher share of energy-intensive production in the industry sector, particularly steel.

Energy intensity falls and GDP per capita grows in all regions in the New Policies Scenario (Figure 7.4). However, access to more energy-efficient technologies and different economic options means that lower income countries and regions follow a different path from that followed in the past by countries that have higher incomes today. By 2040, GDP per capita in India and Southeast Asia is equal to that of Russia in 2016, China in 2025 and almost equal to that of the European Union in 1990. Yet energy intensity and energy use per capita are lower than in each of these other regions at those periods. By 2040, China achieves a similar level of energy intensity to the United States and a similar level of GDP per capita to Russia on a PPP basis.

Figure 7.4 ▷ Energy intensity and energy use per capita in selected regions in the New Policies Scenario



Developing economies follow a less energy-intensive pathway than advanced economies

Note: toe = tonne of oil equivalent; PPP = purchasing power parity.

In India, the extension of the current Perform, Achieve and Trade (PAT) scheme and the direct move from Stage IV to Stage VI vehicle emissions standards by 2020, as announced in 2016, are key drivers of energy efficiency improvements that move the country well below the historical energy intensities of countries at the same level of GDP per capita. In Southeast Asia, regional energy intensity reduction targets in the Association of Southeast Asian Nations (ASEAN) Plan of Action for Energy Co-operation (APAEC) 2016-2025 stimulate new measures. While there remains a gap between advanced and developing economies in 2040 in the amount of energy services – transport, heat, cooling, appliances – consumed per person, closing this gap does not require that the developing economies match the same level of per-capita energy demand. To take one example, a boost in electricity demand from air conditioning may be more than offset by lower space heating needs and the distinction can be reinforced by further energy efficiency, if effectively implemented.

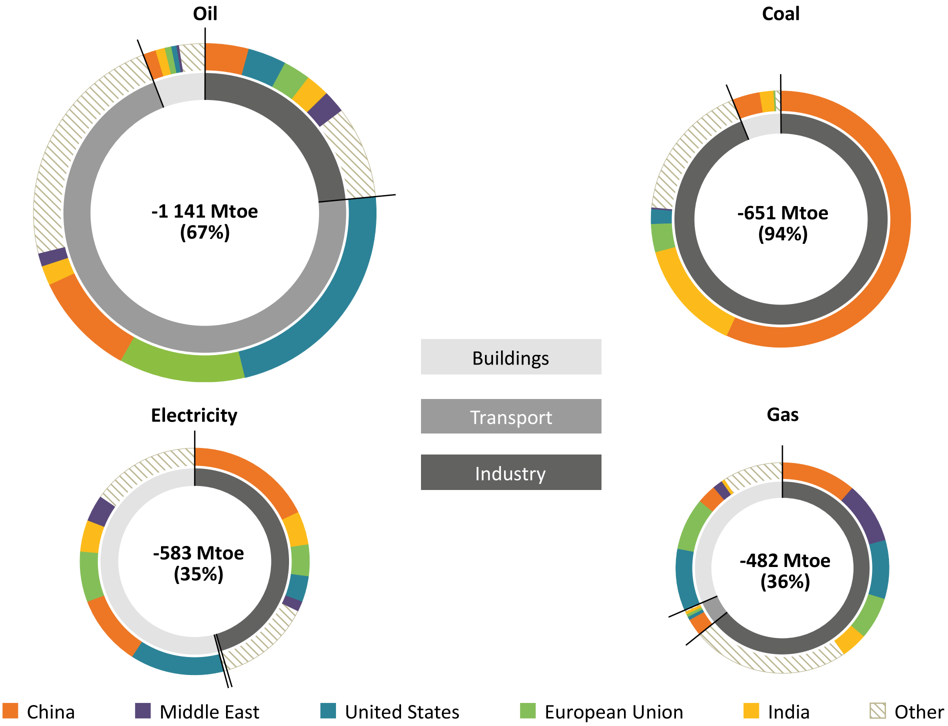
In advanced economies, energy intensity improvements to 2040 are faster in the New Policies Scenario than they were in the period 1990 to 2016, but the effects of structural change, which played a role in the last 25 years, are eclipsed by the effect of efficiency improvements. However, not all advanced economies have lower energy demand per capita in 2040 than 2016: the European Union and the United States continue to reduce their consumption per capita year-on-year based on policy measures: in Japan, demand per capita is flat over the period; in Canada and Australia, higher levels of activity drive up energy demand, though by less than would have been the case without efficiency gains (efficiency savings reduce final energy demand in 2040 by one-fifth in Canada and one-quarter in Australia).

Trends by sector

The impact of energy efficiency improvements on demand for different fuels depends on the sector under consideration. Looking at the efficiency gains in the New Policies Scenario, a relatively small number of key policies is responsible for moderating much of the demand growth in each fuel in 2040. In absolute terms, the largest savings in a given sector and region come from avoided coal use in industry in China (Figure 7.5), which can in large part be attributed to policies to phase out older, more inefficient coal-based capacity and reduce pollutant emissions (Part B of this *WEO* is a special focus on China). The next largest contributions come from reduced oil demand in the transport sectors of the United States and the European Union, where passenger light-duty vehicle (PLDV) fuel-economy standards are set to become more stringent.

The *industry* sector accounts for around half of the avoided energy demand due to energy efficiency by 2040 in the New Policies Scenario. In fast-growing regions, the addition of modern capacity brings down the overall intensity of the industry sector, because it is more efficient than the average of the existing global stock. This dynamic plays an important role across different fuels in China and India, and in the Middle East in relation to natural gas consumption. In addition to regulatory measures, energy management practices are projected to improve and be shared across companies and regions. Adoption of energy management standards such as ISO 50001 facilitates progress. Efficient processes and technologies, such as preheating and pre-calcining equipment for cement kilns, low energy steel production routes, and process integration in chemicals production, in concert with policy measures, are instrumental in improving energy efficiency in the industry sector.

Figure 7.5 ▷ Avoided final energy demand in 2040 due to energy efficiency policies by fuel, sector and region in the New Policies Scenario



Energy efficiency helps to cut half of final consumption growth

Notes: The absolute value shown for each fuel is the avoided energy consumption from energy efficiency improvements in 2040 in the New Policies Scenario. The percentage figures represent the avoided consumption as a share of the growth expected without energy efficiency improvements.

In China, several recent policy developments have significantly changed the outlook for fossil-fuel consumption in industry. China alone achieves more than 40% of the saving in global fossil-fuel energy demand in industry and 60% of the saving in coal demand. Inefficient capacity in coal-intensive sectors, such as cement and iron and steel, continues to be closed in China. Sector-specific energy and pollutant intensity targets have been set for 2020 in the 13th Five-Year Plan in support of the overall targets for industry. China's national emissions trading system (ETS) is to be launched soon, in the power sector as well as selected industries, such as cement and aluminium smelting (see section 13.3.1). The ETS will be expanded over time and carbon prices are expected to increase moderately, triggering the introduction of more efficient and/or less carbon-intensive capacity for new or replacement plants. Globally, energy efficiency measures constrain the growth in industrial demand for coal to around 110 Mtoe, instead of the 720 Mtoe which might otherwise be expected.

In India, the Perform, Achieve and Trade (PAT) programme encourages energy intensity improvements in key industry sectors. Phase 2 of the scheme, which benchmarks site-level performance against best practice and encourages the trading of energy savings certificates, commenced in 2016. This second phase roughly increases by a third the coverage of firms by adding sectors, it targets a 4% reduction in industrial energy use, compared to 2014-15, and builds on Phase 1, which overachieved its goals by 30%. Future cycles of the PAT scheme are proposed to be implemented on a rolling basis, with annual inclusion of new companies. Phase 3 began in April 2017, adding 116 firms. The main benefit of industrial efficiency in India in the New Policies Scenario is nearly 100 Mtoe of avoided coal demand. The European Union is projected to achieve the third-largest reductions in industrial coal use in absolute terms, due to higher efficiency, thanks mainly to binding requirements to adopt best available technologies, the sharing of best practice, and climate policies. In the United States, higher levels of industrial energy efficiency are primarily related to natural gas and oil use. As natural gas prices stay relatively low, oil users have to reduce costs and improve energy efficiency to remain competitive. Efficiency policies, such as the Business Energy Investment Tax Credit, small and medium enterprise (SME) assistance for smart manufacturing technologies and superior energy performance certification system, also deliver industrial oil and gas savings.

Box 7.1 ▷ Motor of change for industrial efficiency

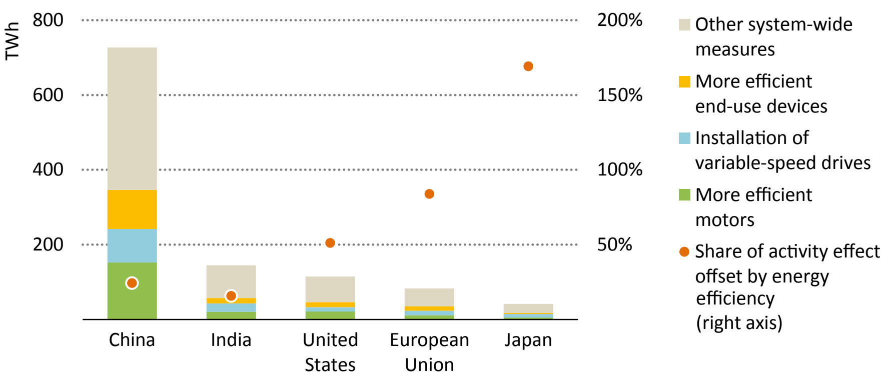
More than half of the electricity consumed globally in all end-use sectors (buildings, industry, transport and agriculture) is used in motor systems. Motors are projected to be a major source of demand growth (see Chapter 7 of the *WEO-2016*). In industry in particular, motor-driven systems give rise to more than 70% of electricity demand, which totalled more than 6 360 terawatt-hours (TWh) in 2016. Electricity demand for motor systems in industry continues to grow, about 70% by 2040 in the New Policies Scenario, reaching 10 850 TWh, due to increased activity and further automation of processes. However, efficiency measures targeting industrial electric motor-driven systems avoid additional growth of around 1 600 TWh.

Better energy performance of motors themselves is a relatively minor source of the efficiency gains in the New Policies Scenario. Most minimum energy performance standards currently establish limits for the motors alone, and these already have efficiencies of 90% and higher. Improved motor efficiency in itself thus accounts for less than 10% of the total electricity savings by 2040 in the industry sector.

Most of the potential for improvement depends on how the electric motors in industry are integrated into equipment and systems. Installing variable-speed drives and improving the efficiency of end-use devices each lead to electricity savings similar in extent to the savings arising from improvements in the motors themselves. System-wide measures, addressing the efficiency of electric motor systems as a whole, play a much larger role, saving more than 900 TWh of electricity consumption (Figure 7.6).[5]

Despite the scope for energy efficiency improvements, electric motor systems remain a major source of electricity demand growth in the industry sector, as energy efficiency offsets only a quarter of the demand growth arising from higher activity levels. Japan and the European Union, however, are exceptions to the global trend: their higher efficiency gains compensate for all or nearly all additional activity-related electricity demand. Systematically addressing the barriers to energy efficiency improvements, through energy labelling, price signals, energy audits and financial incentives would deliver large-scale global electricity savings (IEA, 2016a).

Figure 7.6 ▷ Avoided industrial electricity use in motor systems by region and measure in the New Policies Scenario, 2040



In most regions energy efficiency improvements in electric motor systems in industry are not sufficient to offset the effects of increased activity levels

Industrial gas use and electricity consumption are growth stories in the New Policies Scenario. Rising natural gas demand is tempered by increasing prices in countries that are reforming subsidies (see Chapter 2), though this occurs at a slower pace than previously anticipated. Chemicals production in the Middle East is a major driver of gas demand growth but, as the new capacity is more efficient, the average gas intensity of the sector decreases. On a global basis, electricity demand in industry rises, mainly due to expanding industrial production, but also partly due to the use of efficient heat pumps for provision of industrial heat instead of fossil fuels. To counteract this rise, there is a major opportunity to improve efficiency of electric motor systems, though not all of this opportunity is seized in the New Policies Scenario (Box 7.1). Without energy efficiency, electricity demand in industry in 2040 would be around one-quarter higher.

5. System-wide measures include upgrading system maintenance, matching the equipment to demand needs, correcting system flow problems and increasing the use of smart manufacturing.

In the *passenger road transport* sector, some fuel switching from oil to electricity, natural gas and biofuels takes place in the New Policies Scenario, but the effect on oil consumption is much less than that of the efficiency improvements made to internal combustion engines. Eight countries, in addition to those of the European Union, have so far implemented fuel-economy or greenhouse-gas (GHG) emission standards for light-duty vehicles (LDV). In 2015, they saved oil consumption of 2.7 million barrels per day (mb/d) (IEA, 2017a). This figure reflects the high share (almost 40%) of LDVs in global transport oil demand. Current and planned fuel-economy standards, including their scheduled strengthening, save around 12 mb/d of additional global oil demand in the New Policies Scenario in 2040, an amount equivalent to oil consumption in China today. This is a major reason why oil demand for passenger vehicles peaks by the mid-2020s and is more influential on oil demand than the uptake of electric vehicles (EV).

The US Corporate Average Fuel Economy (CAFE) standard for 2025, which is assumed to be achieved in the New Policies Scenario, reduces the average fuel consumption of new LDVs by 65%, compared with today's level.[6] At present, there is a trend back towards larger vehicles in the United States and there is some uncertainty relating to the reconsideration of the 2017 mid-term CAFE evaluation. Re-opening of the CAFE standards, and no improvement of the fuel economy beyond today, would add 3.2 mb/d of oil demand by 2040 compared with the New Policies Scenario. In 2016, Japan announced the adoption of the Worldwide Harmonized Light Vehicles Test Procedure (WLTP) for passenger vehicles, to help reduce the gap between tested and real-world fuel economy.

To achieve fuel-economy targets the most significant technical improvements are hybridisation, direct injection, variable valve actuation, light-weighting and friction reduction. Worldwide, there are already more than 15 million full hybrid PLDVs on the roads and, by 2040 this number rises to 120 million (mostly in the European Union, Japan and Korea), reducing oil demand by slightly more than 0.6 mb/d. By comparison, the rising momentum of sales of battery electric and plug-in hybrid electric vehicles puts almost 300 million electric cars on the road by 2040, avoiding additional demand of 2.5 mb/d (see Chapter 4). While EVs' contribution to lower oil demand is not categorised as energy efficiency in this analysis, the greater efficiency of EVs does reduce overall energy use in transport.[7]

Oil demand for *freight road transport* continues to rise into the 2030s and beyond. Only five countries (Canada, China, India, Japan and the United States) have adopted standards for heavy-duty vehicles so far. There is much room for improvement and cost savings. Mexico and the European Union are working on such standards, but no official targets had been released as of mid-2017. Beyond rationalisation of freight management – with load factors improving over time as well as a higher reliance on heavy-freight trucks – several measures are available which could achieve energy efficiency improvements beyond the moderate

6. The European Union 2021 target would involve a 25% improvement and the target in China in 2020 would lead to an almost 30% improvement.

7. Without additional policy measures, we do not project a significant impact on PLDV oil demand from shared mobility or autonomous driving over the *Outlook* period.

gains in the New Policies Scenario, including financial incentives and distance-based pricing (IEA, 2017b). By 2040, energy efficiency measures for the medium- and heavy-freight sector are responsible in the New Policies Scenario for a reduction of 3.4 mb/d in oil demand but, overall, freight oil demand is 3.7 mb/d higher in 2040 than 2016, due to an almost doubling of activity.

In *aviation*, a substantial increase in demand is predicted with an accompanying rise in oil demand to 9.4 mb/d in 2040 in the New Policies Scenario, from 6.1 mb/d today. Without energy efficiency improvements, demand would reach about 15 mb/d in 2040.

The *shipping* fleet experiences notable improvements in fuel efficiency. Energy use increases by only 1.7% on an annual basis in the New Policies Scenario, whereas the distance travelled by ships increases by 3.4% each year.

Today, the *buildings* sector accounts for around 53% of global electricity demand and 44% of gas demand. The outlook is for increased demand worldwide, related to a higher share of electricity use in buildings in countries with cooling demand, as well as the increasing penetration of electric heating, and rising ownership of electric appliances and connected devices. In the New Policies Scenario, improved efficiency reduces the growth of electricity demand by twice as much as it reduces gas demand. Around 3 700 TWh (or 320 Mtoe) of electricity consumption is avoided by energy efficiency improvements by 2040, more than the total growth of electricity consumption in India over the same period. Most of this avoided demand relates to equipment with motors (e.g. air conditioners, refrigerators, heat pumps). More efficient equipment and more energy-efficient buildings secure savings in electricity and gas demand. These savings are almost equally split between advanced and developing economies, but while electricity and gas demand growth in buildings is limited to 12% by 2040 in advanced economies, in developing economies electricity and gas demand in buildings more than doubles.

The biggest savings of electricity and gas (120 Mtoe) are achieved in the United States, where the Energy Star and weatherisation programmes, plus more stringent building codes and incentives provided for building efficiency improvements, support ongoing improvements. In the European Union, the implementation of the Ecodesign Directive underpins much of the 80 Mtoe of avoided consumption in the New Policies Scenario, alongside a strengthened Energy Efficiency Directive and the requirement of the Energy Performance of Buildings Directive that all new buildings must have nearly zero energy requirements by the end of 2020. National policies in Europe also play a role, including purchase incentives for efficient heating equipment.

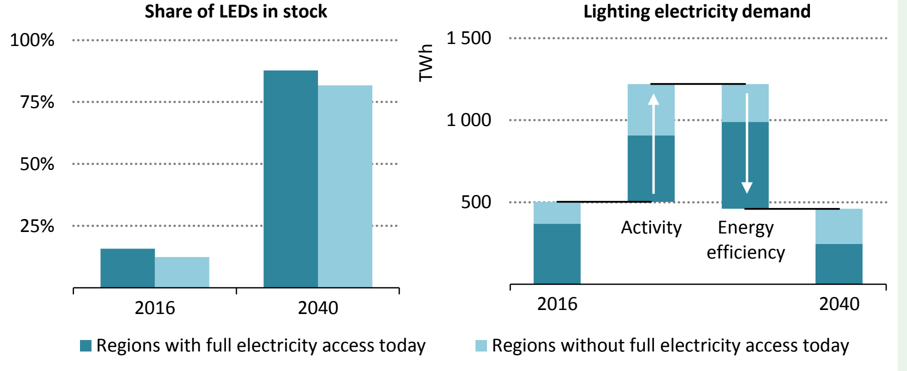
The scope of China's mandatory energy efficiency labelling of appliances and equipment (China Energy Label) has expanded considerably in recent years and continues to have an impact in the *Outlook* period. China's avoided electricity and gas consumption by 2040, due to greater buildings efficiency, is 73 Mtoe. Green building standards, along with air quality measures in several provinces, help to achieve these savings. In Africa and Asia, key developments are the expected strengthening of standards for the rapidly expanding air conditioning markets and support for the deployment of light-emitting diode (LED) lighting.[8] LED costs have been falling, due to technological progress and mass production, both of which are facilitated by policies that make the retirement of inefficient bulbs easier and stimulate faster turnover (Box 7.2).

More than half of the energy efficiency savings of oil and coal used in buildings are in China and India. Alongside fuel switching to electricity or gas, improved efficiency is a key route to lower urban air pollution from heating and cooking in these countries. The social importance of this policy goal has led China to ban coal use in buildings in some cities and to require improved efficiency in coal boilers and building energy performance (e.g. building insulation). In advanced economies, where coal and oil have a much smaller share of the energy used in buildings, action is primarily related to fuel switching, to reduce the GHG emissions from these fuels.

Box 7.2 ▷ LEDs: what role for electrification?

The share of LEDs in residential lighting has grown rapidly in recent years. LEDs represented 30% of global residential light bulb sales in 2016 (up from just 1% of sales in 2010) and 15% of the installed stock. LEDs are much more efficient than other types of lamps, using around 85% less electricity than incandescent bulbs. The cost of LED lamps fell by over 65% between 2012 and 2015 and they have become more reliable and more efficient, which has greatly accelerated their uptake. By 2040, LEDs are projected to make up more than 80% of the global residential lighting stock, partly due to government subsidies, rebates and bulk procurement (Figure 7.7).

Figure 7.7 ▷ Residential LED stock and lighting electricity demand in the New Policies Scenario



Building on recent momentum, LEDs make up most of the lighting stock in 2040 and offset the additional lighting service electricity demand

8. Energy efficiency measures will moderate the growth of cooling energy demand and will be assisted by the Kigali Amendment to the Montreal Protocol on ozone depleting substances (see Box 3.2 in Chapter 3).

LED deployment is projected to proceed quickly in all regions, with rapid growth in India playing a particularly instrumental role in bringing down prices. In India today, around half of the residential bulbs sold are LEDs, already making it one of the biggest LED markets. Government programmes, through the public sector company Energy Efficiency Services Limited, to roll out LEDs and reduce prices for households in order to limit power demand growth are behind this expansion. Had LED sales in 2016 been compact fluorescent lamps, an additional lighting demand of 6.5 TWh would have been created, equivalent to all of the electricity generated by solar photovoltaic (PV) in India that year. By 2040 almost all light bulbs in India are projected to be LEDs, one of the highest shares worldwide.

Policies supporting LED deployment are particularly important in countries which have not yet achieved full electrification, as they can make both lighting services more affordable for consumers and minimise the need to generate more electricity. Today 1.1 billion people lack electricity access, most of them living in Africa and developing Asia (IEA, 2017c). By 2040, an additional 700 million people have secured access to electricity and lighting is a basic need they want to fulfil. These new connections triple the present level of lighting demand in regions not having full access to electricity today, requiring additional generation of over 300 TWh by 2040. Delivering lighting services through LEDs reduces this need by three-quarters.

7.3 Renewables

Policy support, technology and cost improvements, especially for solar PV and wind power, have made renewables a major global industry that will continue to grow in coming decades, largely at the expense of fossil fuels. This is especially true in the electricity sector, where renewables-based electricity generation assets accounted for two-thirds of investment in new capacity in 2016 (see Chapter 6 for discussion of renewables-based electricity). In this section, the general trends in renewables are discussed, with a particular focus on transport and heat applications, to which renewables make a more modest contribution. Yet, there is huge potential for expansion of renewables in these applications, both direct, through the use of bioenergy, geothermal and solar heat, and indirect, through the use of electricity and heat derived from renewable sources. Most of the ensuing discussion deals with both the direct and indirect use of renewables.

7.3.1 Current status

Excluding the traditional use of solid biomass, the share of renewables in primary energy supply in 2016 was 9%.[9] Renewable energy supply has grown by 4% per year since 2000, double the growth rate of total primary energy demand. The power sector

9. This chapter does not include the traditional use of solid biomass unless otherwise stated, as its use, primarily in inefficient and poorly ventilated cookstoves in developing economies, is neither sustainable nor desirable. 2.8 million premature deaths per year are attributed to the resultant household air pollution.

is the principal domain of renewable energy, accounting for nearly 60% of its use, with a quarter of all electricity generation in 2016 coming from renewable energy technologies, up one percentage point from 2015. Hydropower is by some distance the largest source of renewables-based electricity, though there has been a slowdown in hydropower investment decisions. The cost and performance of wind and solar PV is improving more quickly than other renewable sources; their combined output is estimated to have been nearly 20% higher in 2016 than in 2015.

The role of renewables in heat and transport is less developed, with direct and indirect renewables supplying 9% of heat demand in buildings and industry, and 3% of transport energy demand in 2016. Investments in transport biofuels and solar heating fell about 25% in 2016, both due to a reduction in policy support and to a general slowdown in these markets (IEA, 2017d). Despite growing competitiveness, government targets and support policies remain the driving force behind much of renewables-based electricity growth. Direct use of renewables in heat and transport is generally less competitive and remains heavily reliant on policy support in most regions.

Recent policy developments

Renewables policies take a variety of different forms, including direct subsidies to offset their higher costs and capital-intensity, market adjustments to reflect their system value, support for technological innovation, portfolio standards, fuel blending mandates, and pricing to account for the emissions-related externalities of other fuels. As is the case of policy interventions to encourage energy efficiency, renewable energy policies also generally serve multiple goals, including: improving energy security, reducing local air pollution, combating climate change and stimulating economic activity and technology leadership.

The number of developing economies with targets for renewables has risen dramatically: for example, there are close to fifty members of the Climate Vulnerable Forum aiming to reach 100% of domestic energy production from renewables by 2050. While over 155 countries have adopted specific policies for renewables-based power, less than 100 have policies in place for direct use of renewables for heat or biofuels in transport. Most of the new targets since mid-2016 have been focused on the power sector (Table 7.2). Much of recent activity has been concerned with the provision of regulations and guidelines to implement policies already on the statute books. As described in Chapter 6, a major trend in renewables policies in the power sector has been a shift away from direct subsidies towards measures that encourage competition, seeking the lowest cost projects while continuing to provide revenue certainty to reduce investment risk, in particular via auctions.

Many countries have updated their policies for biofuels blending since mid-2016, but the European Commission has confirmed that there will be no specific target for biofuels in the European Union (EU) transport sector after the expiration of the current 10% target for renewable energy in transport in 2020. The proposed revision to the EU Renewable Energy Directive sets a cap on conventional biofuels in transport energy use, decreasing to 3.8% in 2030 and targets 6.8% advanced alternative fuel use in transport in 2030.

Table 7.2 ▹ Selected renewable energy targets proposed or introduced since mid-2016

Country	Sector	New/revised target in 2016
Argentina	Transport	Increase in mandatory blending of bioethanol from 10% to 12%.
Brazil	Electricity	174 GW by 2024 (10% biomass, 5% small hydro, 14% wind, 4% solar).
	Transport	Mandatory 8% blending of biodiesel by 2017; 10% by 2019.
China	Electricity	380 GW hydro, 210 GW wind, at least 110 GW solar by 2020.
Cuba	Electricity	2.1 GW by 2030.
Egypt	Electricity	4.3 GW to be installed 2015-17 (53% solar PV, 47% wind).
Ethiopia	Electricity	7 GW wind by 2030.
European Union	Heat	Energy suppliers endeavour to increase renewables share in heating and cooling by one percentage point per year to 2030.
	Transport	At least 6.8% of low-emission and renewable fuels use by 2030, and decreasing targets on conventional biofuels, from 7% in 2021 to 3.8% in 2030.
Finland	Transport	40% share of transport fuel by 2030 (including mandatory 30% blending of biofuels).
France	Electricity	18 GW solar by 2023, 22 GW wind by 2023, 26 GW hydro by 2030.
	Heat	Consumption for heating and cooling: 13 Mtoe bioenergy, 270 thousand tonnes of oil equivalent (ktoe) solar thermal, 700 ktoe biogas, 400 ktoe geothermal by 2023.
India	Transport	Mandatory 22.5% blending of bioethanol and 10% biodiesel by 2022.
Indonesia	Electricity	5 GW solar by 2020.
	Transport	Mandatory 20% blending of biodiesel implemented in 2016.
Jordan	Electricity	1.8 GW by 2020 (56% solar).
Malaysia	Transport	Mandatory 10% blending of bioethanol and 10% biodiesel implemented in 2016.
Mexico	Transport	Mandatory 5.8% blending of bioethanol implemented in 2016.
Saudi Arabia	Electricity	9.5 GW by 2023.
Thailand	Electricity	3 GW solar PV by 2021 and 6 GW by 2036.
United States	Transport	73 billion litres of biofuels by 2017.
Viet Nam	Transport	Mandatory 5% blending of bioethanol implemented in 2017.
Zimbabwe	Transport	Mandatory 10% blending of bioethanol implemented in 2016.
Climate Vulnerable Forum[10]	Production	Strive for 100% of domestic energy production to be renewables-based by 2050.

10. *https://thecvf.org.*

Recent market developments

Renewables now make up a larger part of the new electricity capacity installed each year than coal, natural gas or nuclear. In 2016, renewables provided almost two-thirds of the 4% growth in global electricity capacity, which rose by more than 260 GW to reach 6 680 GW. Wind and solar PV are growing faster than other sources of renewables; their capacity additions in 2016 were about 10% higher than in 2015. All renewables-based capacity additions in 2016 represented $297 billion of investment.

Investment in solar heating fell from $22 billion to $16 billion in 2016. The technology does not benefit from the same levels of support as renewables-based electricity and competes with current low fossil-fuel prices in some regions, together with approaching market saturation in former high-growth markets. China's use of renewables for heat in buildings, primarily in the form of solar thermal, more than doubled in the period 2010-16, but since a relevant incentive programme came to an end, the solar thermal market in China has slowed.

Production of transport biofuels is led by the United States, which is by far the largest producer and consumer. Output of US bioethanol increased by 3% in 2016 to 58 billion litres in 2016, to meet 7.8% of gasoline demand (in energy terms). Brazil is the second-largest global bioethanol producer, at 28 billion litres in 2016, 750 million litres of which was exported and the rest devoted to supplying 40% of domestic gasoline demand. However, output fell 6% in 2016, as sugar became a more commercially attractive product from sugarcane than bioethanol, at a time of low oil prices. The Brazilian government may adopt additional measures to support bioethanol and reduce gasoline imports, on top of the 2015 tax measures promoting E100, instead of E27.[11] Bioethanol production in the European Union in 2016 fell by 9%, to around 4.6 billion litres, while EU biodiesel production increased modestly to the record level of 13.5 billion litres.

7.3.2 Outlook for renewables

Trends by scenario

Announced policies are set to have a noticeable impact, with 370 Mtoe more renewable energy projected to be supplied in 2040 in the New Policies Scenario than in the Current Policies Scenario (Table 7.3). In the Current Policies Scenario, the contribution of direct and indirect renewable energy to total final energy consumption increases from 9% in 2016 to 13% in 2040, an increase of 900 Mtoe. Almost half of the increase comes in the form of heat, while the renewable share of transport fuels only increases from 3% to 4% by 2040. On the basis of the announced policies and targets considered in the New Policies Scenario, the change is larger, but not dramatically so. Renewables consumption increases by an additional 266 Mtoe by 2040 in end-use sectors. Biofuels consumption in transport increases by an additional 1 mboe/d by 2040, while renewables-based heat consumption is 6% higher.

11. E100 is pure hydrated ethanol and E27 is a fuel composed of 27% of anhydrous ethanol in gasoline. Most cars in Brazil are flex-fuel and can operate on any blend of ethanol and gasoline.

Table 7.3 ▷ World renewable energy consumption by scenario

		New Policies		Current Policies		Sustainable Development	
	2016	2025	2040	2025	2040	2025	2040
Primary demand (Mtoe)	**1 251**	**1 791**	**2 910**	**1 715**	**2 541**	**1994**	**4 049**
Share of global TPED	*9%*	*12%*	*17%*	*11%*	*13%*	*14%*	*29%*
Traditional use of solid biomass (Mtoe)	**678**	**642**	**557**	**642**	**557**	**340**	**102**
Share of total bioenergy	*50%*	*42%*	*31%*	*43%*	*32%*	*27%*	*7%*
Electricity generation (TWh)	**6 021**	**9 316**	**15 688**	**8 840**	**13 160**	**10 625**	**22 664**
Bioenergy	570	867	1 424	833	1 211	952	1 807
Hydropower	4 070	4 804	6 193	4 755	5 964	4 986	6 928
Wind	981	2 192	4 270	1 983	3 358	2 785	6 950
Geothermal	86	140	349	134	281	170	563
Solar PV	303	1 264	3 162	1 096	2 192	1 629	5 265
Concentrating solar power	11	44	237	36	130	99	1 066
Marine	1	4	53	3	25	5	85
Share of total generation	*24%*	*31%*	*40%*	*29%*	*31%*	*38%*	*63%*
Final consumption (Mtoe)[1]	**882**	**1 273**	**2 051**	**1 209**	**1 785**	**1 478**	**2 886**
United States	132	182	257	172	235	230	429
European Union	179	232	305	223	274	247	338
China	145	259	472	235	380	312	622
India	54	97	197	94	171	113	277
Share of global TFC	*9%*	*12%*	*16%*	*11%*	*13%*	*15%*	*28%*
Heat consumption (Mtoe)[1,2]	**456**	**599**	**897**	**585**	**842**	**647**	**1 097**
Industry	225	289	420	291	421	301	485
Buildings and other[3]	231	309	476	294	422	346	612
Share of total heat demand	*9%*	*11%*	*15%*	*11%*	*13%*	*13%*	*23%*
Biofuels (mboe/d)[4]	**1.7**	**2.6**	**4.2**	**2.2**	**3.3**	**4.2**	**8.1**
Road transport	1.7	2.5	3.8	2.2	3.2	3.5	5.6
Aviation and Maritime[5]	<0.1	0.1	0.5	<0.1	0.1	0.7	2.6
Share of total transport fuels	*3%*	*4%*	*6%*	*3%*	*4%*	*7%*	*16%*

Note: Mtoe = million tonnes of oil equivalent; TPED = total primary energy demand; TFC = total final consumption; TWh = terawatt-hours; mboe/d = million barrels of oil equivalent per day.

[1] Includes indirect renewables contribution, but excludes environmental heat contribution. [2] Coke ovens and blast furnaces are included in the industry sector. [3] Other refers to desalination and agriculture. [4] In energy-equivalent volumes of gasoline and diesel. [5] Includes international aviation and maritime bunkers.

In the New Policies Scenario, electricity generation from renewables, led by wind and solar PV, grows almost three-fold by 2040 and the share of renewables in electricity generation rises from 24% to 40%. With the share of variable renewables in the generation mix passing 25% in several regions, including the European Union, India and Mexico, their full integration into the electricity system requires dedicated investments and smarter operations

(IEA, 2016a). Indirect renewables expand their share in all end-use sectors, especially those in which demand coincides with the best times for wind and solar generation.

With less policy attention, the direct use of renewables for heat and transport grows more slowly than their use in the power sector. In the New Policies Scenario, direct and indirect use of renewables accounts for 15% of total heat demand and 7% of final transport energy demand in 2040. Indirect use of renewables grows faster than direct use of renewables in both sectors in the New Policies Scenario. In transport, the growth rate is over twice as fast but, in energy terms, the amount of renewables-based electricity in transport reaches only about 60% of the level of biofuels use in 2016. Bioenergy continues to be the largest source of direct renewable energy use in heat supply and is the only direct renewable energy source in transport.

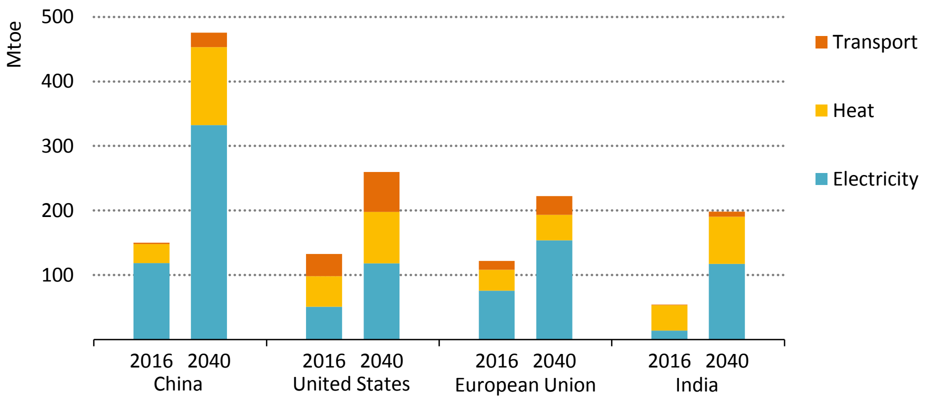
Progress in the New Policies Scenario is insufficient to meet the climate and development goals of the Sustainable Development Scenario, in which renewable energy supply grows by 5.0% per year, compared to 3.6% in the New Policies Scenario, more than tripling by 2040. Additional measures in the Sustainable Development Scenario to incentivise investment in renewables-based electricity, bioenergy, solar heat, geothermal heat and electrification, at the expense of fossil-fuel use, push the share of renewables to over 60% in the power mix, 21% in transport and 23% in heat (including indirect use in transport and heat). In particular, the Sustainable Development Scenario sees much greater progress with advanced biofuels, output of which grows to about 120 Mtoe in 2040, compared to about 50 Mtoe in the New Policies Scenario.

Trends by region

In the New Policies Scenario, renewables contribute an increasing share to total primary energy demand in all regions, and are growing in almost all sectors. Today, China is the leading country in renewable energy use and increases its share of global renewable energy supply from 15% in 2015 to 20% in 2040 (600 Mtoe). In the United States today, consumers use renewables to the same extent in their heat and electricity consumption, but this changes after 2020, as use of renewables-based electricity grows faster than the use of renewables for heat and transport combined (Figure 7.8). However, under the existing and planned policies in the New Policies Scenario, the annual rate of growth of renewables in the United States slows from 3.5% per year to 2.5% per year after 2025. In the European Union, electricity generation from renewables grows at a slightly slower rate than in the United States, as does renewable heat. In Japan, Korea and Australia, power is the only sector that sees significant growth of renewables in the New Policies Scenario.

In Southeast Asia, rising energy demand is the main driver of renewable energy expansion, and as costs decline, the growth rate of renewables is almost twice that of total final energy consumption. However, Southeast Asia's share of global renewables supply stays flat, at around 7%. Brazil is among the countries with the highest share of direct and indirect renewable use in final energy demand, the share growing to around 45% in 2040, from 39% today.

Figure 7.8 ▷ Renewable energy use by sector from a consumer perspective and by region in the New Policies Scenario



Renewables-based electricity leads the expansion in renewable energy use

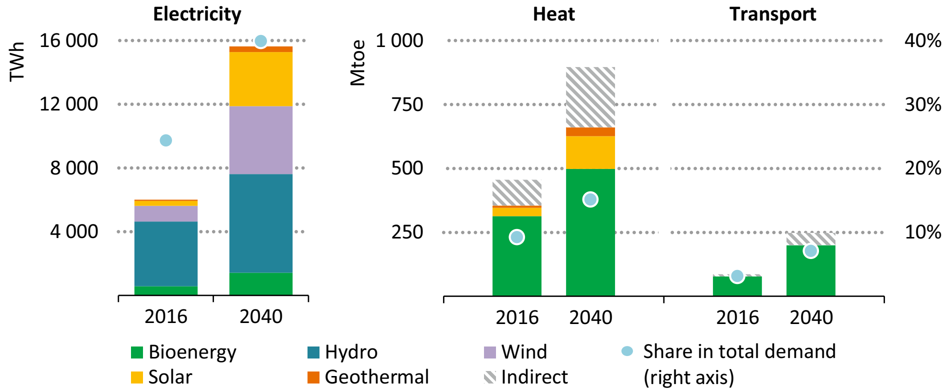
Note: All sectors are considered from a consumer perspective, i.e. electricity shown represents the share of electricity demand provided by renewables, including electricity used for transport and heat.

Trends by sector

The *power* sector accounts for the largest share of growth in renewable energy through 2040 in the New Policies Scenario, reflecting both policy priorities and improving costs relative to fossil fuels. In absolute terms, the largest contribution to this growth comes from wind, which more than quadruples, followed by solar PV, which grows ten-fold (Figure 7.9). Despite losing market share, hydropower increases by 50%, remaining the largest source of renewables-based power. Bioenergy-based electricity generation more than doubles by 2040, but the growth rate slows after 2025, as does that of concentrating solar power, output of which does not rise above 10% of the output of solar PV over the *Outlook* period. The rate of growth of electricity from geothermal resources accelerates, reaching about 6% per year through 2035, but in 2040 it supplies less than 1% of total electricity generation.

Heat demand accounts for more than half of global final energy consumption today (nearly twice the level of transport) and can be met, using renewables, in several different ways. Renewables for heat can be derived directly from bioenergy, geothermal or solar thermal or indirectly via renewables-based electricity or renewables-based heat supplied from district heating systems. The main source of direct renewable heat is bioenergy, which accounted for almost 70% of the total in 2016 (with more than 40% used in the United States, Europe, India and Brazil), and is commonly used to generate heat for commercial applications. As a combustible fuel, biomass can provide higher temperature heat than other renewable sources, which makes it more suitable for use in some industrial applications (IEA, 2016a).

Figure 7.9 ▷ **Renewable energy use by sector and source in the New Policies Scenario**



The lack of support and policies aimed at heat and transport demand leads to a smaller increase of renewables in these sectors

Note: Share in total demand for heat and transport includes both direct and indirect contributions.

In the New Policies Scenario, heat demand grows from more than 4 900 Mtoe in 2016 to 5 900 Mtoe in 2040, with 45% of this growth being met by direct and indirect renewable sources. Bioenergy use for heat increases by 185 Mtoe. Half of this growth is in China, India and the European Union, each of which have policies in place or are planning policies to increase the use of bioenergy for heating in industrial applications. In particular, China's 13th Five-Year Plan provides for the use of bioenergy in industrial and residential heat to increase by around 2 Mtoe per year to 2020, establishing an industry that delivers one-quarter of the global growth in bioenergy for heat over the *Outlook* period. In Brazil, where incentives lead to increasing bioenergy use in industry, direct renewables use for heat grows by almost 40% by 2040. Depending on the control technologies applied, increased biomass consumption may increase particulate matter (PM) emissions but decrease emissions of other air pollutants (see Chapter 3).

Under existing and planned policies, rooftop area dedicated to solar for space and water heating grows at a rate half that of solar for electricity generation. However, rooftop solar thermal can be more productive than solar PV (Box 7.3). One of the fastest growing regions for solar heat is the Middle East, which accounted for just 0.6% of solar heat in 2016 but contributes one-quarter of the growth to 2040, more than anywhere, except China. Growing demand for desalination in the Middle East is an important driver of solar thermal growth in the region (IEA, 2016a). New policies to overcome site-specific constraints to geothermal expansion are not widely introduced and the geothermal growth rate slows compared to the last 25 years in the New Policies Scenario. In 2040, direct use of geothermal heat contributes 4% of renewable heat worldwide, mostly in China and the United States.

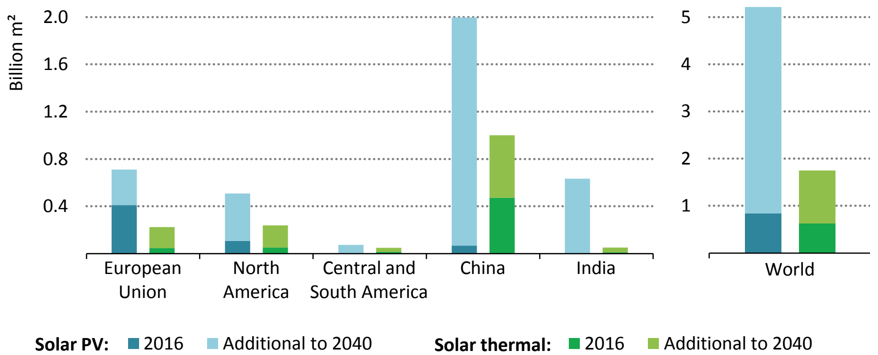
Box 7.3 ▷ Relative merits of rooftop solar PV and rooftop solar thermal

One of the notable trends for renewables in the New Policies Scenario is that electricity generation from solar PV on rooftops grows as quickly as utility-scale solar PV. However, rooftop area is a resource that can also be used to capture solar energy for water heating, or to a lesser extent, for space heating. Today there is slightly more solar PV on rooftops than solar thermal. Over the *Outlook* period, solar PV grows to triple the rooftop area of solar thermal by 2040, largely due to capacity additions in China and India (Figure 7.10).

Rooftop solar PV is less productive per square metre, reaching around 150-300 kilowatt-hours per square metre (kWh/m^2) of electricity generated annually (depending on the solar insolation). Solar thermal, on the other hand, can produce more than 500 kWh/m^2 of heat, and can reach as much as 1 000 kWh/m^2 in areas of high solar insolation, such as parts of Africa. The optimal solution varies from region to region and from rooftop to rooftop (see Chapter 11 of *World Energy Outlook-2016*).

Direct solar thermal can be attractive to meet onsite demand for hot water or space heating: storage of heat in water tanks is generally more cost effective than storage of electricity. On the other hand, solar PV installations do not require additional plumbing work and, under current policies, many utilities allow consumers to sell excess power to the grid thereby reducing net electricity bills. This is rarely possible for solar thermal heat. Furthermore, electricity is typically a higher value energy carrier than heat, reflecting its use for many different applications, including in heat pumps, which in some circumstances can be more efficient than solar thermal for converting solar energy to heat. Where roof space allows, joint solar PV and solar thermal may be an economic choice, possibly integrated in a single hybrid unit. Today hybrid PV and solar thermal is currently a costly technology with a small market share, but costs are expected to decline.

Figure 7.10 ▷ Solar PV and solar thermal rooftop area in the New Policies Scenario



Solar PV largely exceeds solar thermal in terms of rooftop area by 2040

In the *transport* sector, despite the growth in electric vehicles in the New Policies Scenario, biofuels are still by far most important form of renewable energy in 2040. However, with the scale-up of renewables in power generation and the expansion of electric vehicles, the share in transport energy demand of electricity produced from renewables grows from 0.3% today to 1.4% in 2040, and given the higher fuel efficiency of electric vehicles, renewables-based electricity accounts for 5% of the total kilometres driven worldwide in 2040, compared to 4% for biofuels. From the 580 TWh of renewables-based electricity used in 2040, slightly more than a half is used in road transport and less than 50% in rail.

Liquid biofuels do not require changes to refuelling behaviour and are also suitable for use in freight and air transport, as well as LDVs. However, while global consumption of biofuels grew at 12% per year over the last ten years, the rate of growth slows to 4% per year in the New Policies Scenario. This slowdown is largely explained by the progressive reduction of production subsidies to conventional biofuels in Europe and China, as well as the relative ease of doubling production in the past from a low base, compared to doubling the current 78 Mtoe of output. The reduction of subsidies for conventional biofuels in some countries reflects growing unease about the sustainability of producing large quantities of energy products from food crops (Box 7.4). In the European Union and United States, advanced biofuels, for which there are fewer environmental and social concerns but higher technical and cost challenges, account for an important share of the additional biofuel demand in the New Policies Scenario.

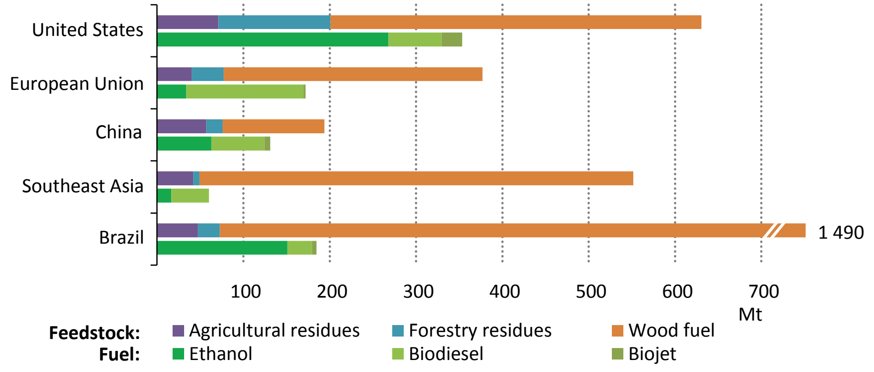
In the New Policies Scenario, 10% of the global demand from gasoline-fuelled vehicles is met by bioethanol in 2040, compared to 5% today. 6% of global diesel-fuelled vehicles demand is met by biodiesel, compared to 3% today. In the United States, which remains the world's largest market for biofuels, expansion in conventional biofuel consumption slows as advanced bioethanol and biodiesel production grows. In 2040, advanced biofuels account for more than 40% of the 1.3 million barrels of oil equivalent per day (mboe/d) of biofuel use. Brazil's biofuels market is today the second-largest globally, with the highest share of biofuels in the transport fuel mix. Following the government's announcement of a floating tax to shelter the domestic ethanol industry, which is linked to international oil prices, 85% growth in ethanol consumption is projected by 2040, its share in transport energy demand rises from 18% to 24%, almost entirely based on bioethanol production from sugarcane. Under the assumptions of the New Policies Scenario, four Southeast Asian countries also promote consumption of domestic biodiesel, which more than doubles by 2040, surpassing the current European Union blend rate of 6.5%. Indonesia and the Philippines are particularly ambitious with mandates for biodiesel blend rates of 30% and 20% respectively in 2025. In China, transport policies are concentrated primarily on the electrification of urban vehicles to reduce local air pollution, and given the size of China's market, this may reduce automakers' focus on better engines for biofuels use and, thus, their availability. As biofuels do not have a similarly beneficial impact on air quality and can actually exacerbate pollution in some cases, biofuel development in China is projected to be limited: in 2040, biofuels account for less than 4.5% of energy consumption in the transport sector in China.

Box 7.4 ▷ Is an advanced biofuels revolution feasible with domestic and sustainable biomass supply?

Biofuels have been supported in many countries to increase energy security, maintain and create rural employment, and mitigate GHG emissions from transport. However, in recent years there has been a serious debate about the environmental and social impacts of their large-scale development, including the scale of net GHG emission reductions achieved and whether biofuel production increases food prices for poor communities. One outcome has been the implementation in 2015 of a 7% blending cap for biofuels derived from food-based feedstocks in the European Union. However, there are currently few calls for the biofuels sector to move away from food crops entirely and it is recognised that sugarcane bioethanol production in Brazil has a relatively favourable carbon footprint.

If biofuels were produced only from sustainable non-edible feedstocks, using advanced processes (technologies which convert lignocellulosic material into biofuels), the potential is still large (Figure 7.11). Sustainable feedstocks are mostly lignocellulosic material from agricultural residues (such as straw) and forestry residues (such as branches, sawmill by-products and wastes). In the largest consuming regions, most of the feedstock potential comes in the form of additional forest biomass that can be sustainably harvested and dedicated energy crops on marginal lands, with agricultural and forestry residues together accounting for around one-sixth.

Figure 7.11 ▷ Potential sustainable feedstock and requirements to meet biofuels demand in the New Policies Scenario, 2040



Biofuels can be produced with advanced processes using domestic sustainable biomass feedstock in the New Policies Scenario

Notes: Wood fuel potential represents the forest biomass increment which is technically recoverable without further deforestation and dedicated energy crops on marginal lands, minus industrial production and minus primary bioenergy demand from the buildings, industry and power sectors. Use corresponds to biomass feedstock required to produce biofuels consumed, with technologies processing lignocellulose.

Sources: IEA; MINES ParisTech.

7

The potential in Brazil and Southeast Asia in particular is well above the quantity of bioenergy required to meet transport demand in the New Policies Scenario. In the United States and Europe, sustainable feedstocks could provide twice the level of demand, and the figure is 150% in China. In the United States, agricultural and forestry residues alone could provide more than half the required feedstock. Most woody biomass is not, therefore, needed for transport biofuels and would be amply available for construction and furnishing, bio-based chemistry and other fuel uses.

While some progress has been made on advanced processes in recent years, fuels produced from lignocellulosic feedstock remain less competitive than conventional biofuels in most regions.[12] Achievement of the levels of unconventional supply assumed in the New Policies Scenario depends on existing and planned policies delivering performance improvements and cost reductions through research and development (R&D), as well as large-scale market creation and support for early commercial projects (IEA, 2016a). There could also be important spin-offs from R&D into the use of captured CO_2 for algae production as feedstock for fuels, though no large-scale applications have been developed and none are assumed in the New Policies Scenario.

7.4 Some implications

Most energy investments involve both initial capital costs and substantial continuing operational costs (especially fuel), but the vast majority of the costs of energy efficiency and renewable energy technologies lie in the upfront capital expenditures. As energy efficiency and renewables play an increasingly large role in meeting the world's energy needs in the New Policies Scenario, the energy system accordingly becomes more capital intensive. Attracting the necessary level of investment should not obstruct their growing contribution, but market design and business models may need adjustment, with costs and benefits allocated between consumers, governments and the broader energy system. Governments will play an active role in the process, for example through the introduction of carbon pricing. Overall, the New Policies Scenario delivers lower consumer energy bills and lower fossil-fuel import bills.

Improving energy efficiency over time requires wider deployment of technologies with longer payback periods, usually implying higher economic cost. Similar considerations apply to renewables; while significant deployment is projected for power generation, the high upfront costs of some renewable heat technologies make them less competitive than other solutions under certain circumstances, slowing their deployment, (see Chapter 11 in *World Energy Outlook-2016*). The economics of energy efficiency and renewables vary across regions and scenarios, due to differences in regional market conditions (e.g. fossil-fuel prices, material and labour costs) or the time-of-use of equipment.

12. Worldwide there are currently more than ten large-scale bio-refineries producing advanced biofuels.

7.4.1 Investments in renewables and energy efficiency

Investment in energy efficiency continued to expand in 2016, increasing by 9%, despite low energy prices, to reach $231 billion or more than 10% of global total energy investment (IEA, 2017d). Government policies continued to encourage the purchase of more energy-efficient equipment and appliances as well as the refurbishment of buildings. The bulk of related spending occurred in Europe, but the largest growth in expenditure was recorded in China, where stronger energy efficiency policies were implemented. In the New Policies Scenario, energy efficiency investment increases in all end-use sectors, especially in transport and buildings (Figure 7.12). This is partly driven by the economic benefits of lower energy costs, but also results from measures, such as performance standards, that can initially raise equipment costs for users.[13] In the industry sector, efficiency investments primarily occur in non energy-intensive industries in the New Policies Scenario. Investment in efficient electric motors, variable speed drives (VSD) and heat pumps represents nearly 30% of the energy efficiency investment in the industry sector to 2040. In buildings, 60% of investment occurs in the residential sector, of which 40% goes into better insulation and about the same level into more efficient appliances. The remaining 40% of investment in buildings is in the services sector, one-third for insulation. More than half of the investment in the transport sector is made in LDVs, and most of the remainder is for other forms of road transport. However, in the absence of existing and planned policy measures, investment in freight vehicles attracts around one-quarter of the total energy efficiency investment in road transport. The corollary is that freight transport represents one of the main drivers of oil demand by 2040.

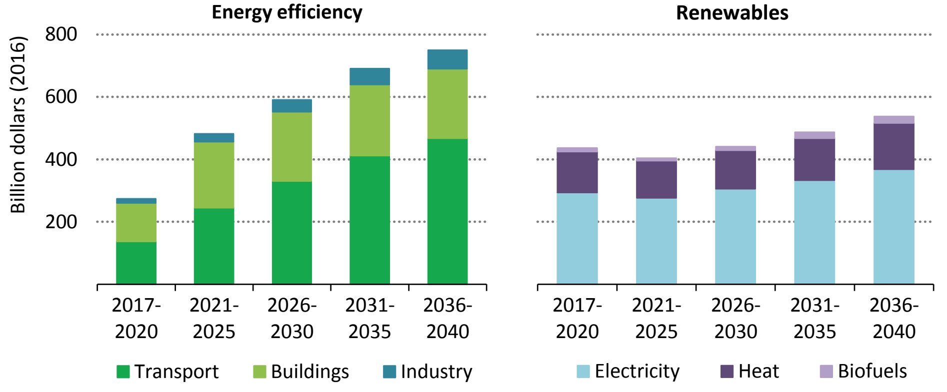
In 2016, investment in new renewables-based power capacity, at $297 billion, was larger than investment in new fossil-fuel-based and nuclear plants, even though it was down 3% from the 2015 level (IEA, 2017d). Much of the decline can be attributed to fewer wind and hydropower capacity additions and the lower unit costs associated with technological progress. Global investment in renewables-based heat and the supply of renewable transport fuels was 25% lower in 2016 than the previous year, reflecting lower fossil-fuel prices and weak policy support.

In the New Policies Scenario, investment in renewable energy supply increases moderately, tempered by falling unit costs throughout the *Outlook* period (Figure 7.12). Renewables in the power sector attract the largest share of investment, followed by renewables in the buildings sector (more than half of which is for solar thermal), in industry and, lastly, in biofuels for transport. Among technologies, wind and solar power each account for more than one-third of the investment in renewables-based electricity generation in 2040. By the late 2020s, investment in wind power returns to current levels in real terms, while investment in solar returns to current levels by the late 2030s. In relative terms,

13. Nonetheless, analysis indicates that more stringent energy efficiency policies have tended to result in consumers getting better quality products without paying more. For example, after a brief increase, appliance prices in many cases have continued to decline in real terms following the introduction of energy performance standards, especially when adjusted for appliance quality (IEA, 2017a).

investment in biofuels grows fastest, mostly in the United States, the European Union and Brazil. This gradation broadly reflects the policy attention afforded to the various renewable energy technologies. In the near term, existing and planned policies are insufficient to expand investment at a faster rate than costs decline, leading to slightly decreasing investment in the timeframe to 2025.

Figure 7.12 ▷ Average annual global energy efficiency and renewables investments in the New Policies Scenario



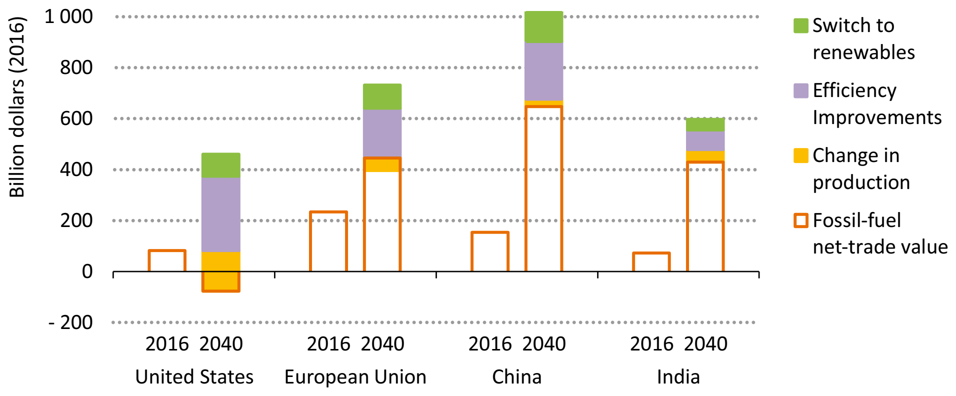
Investment in renewables is broadly constant to 2030 and then increases, while investment in energy efficiency ramps up to exceed renewables by the early-2020s

Under current and existing policies, investment in energy efficiency and renewables represents around 40% of cumulative global energy investment to 2040. Although tempered by the benefits of investment in energy efficiency and renewables-based heat, household energy expenditures are on average 23% higher in 2040 than today. Growth is driven by rising end-user energy prices (caused by higher oil and gas costs, the phase-out of subsidies and carbon pricing) and increasing energy service demand, especially in developing economies.

7.4.2 The impact of renewables and energy efficiency on import bills

The distribution of global income is affected by tempered demand growth for oil, gas and coal, due to energy efficiency and renewables. Importing countries reduce their import bills, whereas countries with reduced export revenues have to find alternative income streams. A lower share of energy imports in national energy demand contributes to enhanced energy security in importing countries. In the New Policies Scenario, the US fossil-fuel trade deficit is reversed during the *Outlook* period, with efficiency and renewables (especially improvements in the transport sector that curb oil demand) making a more important contribution than increased domestic fossil-fuel production, (Figure 7.13). Import costs of about $350 billion per year are avoided in China, and around $285 billion per year in the European Union. In India, import savings amount to around $120 billion per year (almost double net fossil-fuel import costs in 2016), equal to more than 1% of GDP in 2040.

Figure 7.13 ▷ Fossil-fuel net-import bills for selected regions and savings enabled by energy efficiency and renewables in the New Policies Scenario



Efficiency improvements and greater use of renewables help reverse the US fossil-fuel trade deficit by 2040

7.5 Interlinkages between energy efficiency and renewables

As renewable energy and energy efficiency technologies command higher levels of attention, (including through global initiatives such as the Sustainable Development Goals[14]) and achieve higher levels of deployment, addressing these two factors independently is no longer appropriate. While a holistic system-wide perspective has always been desirable, in practice policies and corporate strategies have often been made separately for different fuels and sectors, and without much cross-reference between renewables and energy efficiency. Both energy efficiency and renewables bring new qualities to energy systems, particularly as they grow in importance, but relatively little attention has been given so far to their integration, for example in climate and energy security policy-making.

Another related cross-cutting trend is electrification. Achieving a higher share of renewables is facilitated in two ways by the electrification of heat and transport: it enables the indirect use of renewables in these sectors and it introduces new, more flexible sources of electricity

14. Both energy efficiency and renewables have an important role to play in sub-Saharan Africa in providing full access to electricity and clean cooking (see Chapter 4, *Energy Access Outlook* [IEA, 2017c]).

demand that can be adjusted to more readily match the availability of renewables-based electricity generation. Electrification can also improve overall energy efficiency where new technologies, such as heat pumps and electric vehicles, have better energy performance. Investment in energy efficiency reduces overall demand, enabling renewables to capture a higher proportion of supply. In developing economies, commercial packages of highly efficient appliances and solar PV can make a range of energy services both affordable and available to households (IEA, 2017c).

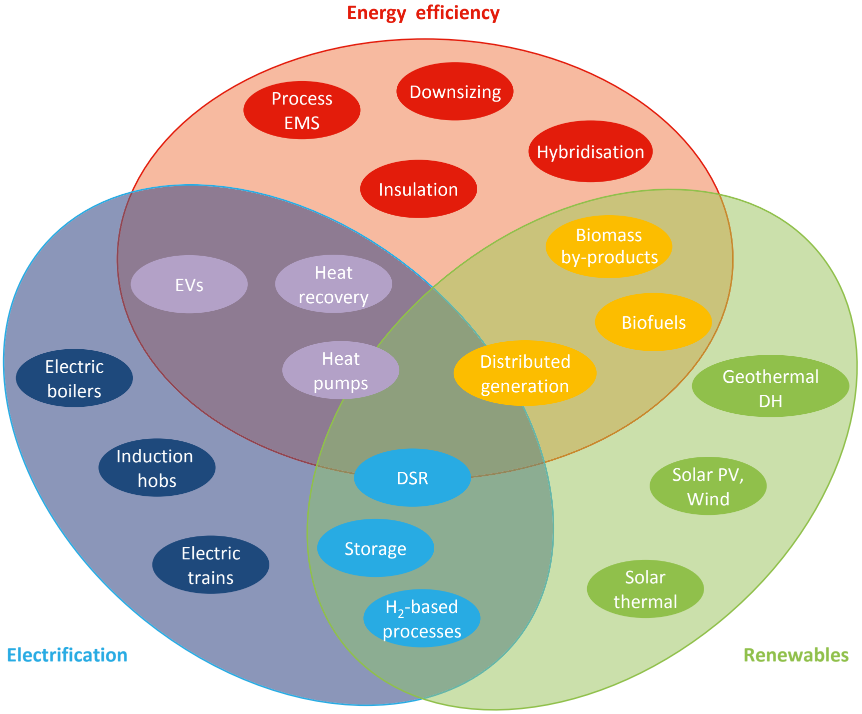
The energy strategies being developed by and for major commercial energy consumers today are increasingly integrating efficiency and renewable energy. Many large retailers and manufacturers have sustainability targets which include increasing the share of renewable energy and reducing overall energy consumption. Solutions are available that combine technologies, such as solar PV, solar heating, heat pumps, LEDs, batteries and digital energy management systems in a variety of ways. As the costs of solar and digital controls have fallen, these have been incorporated into energy management toolboxes alongside more traditional energy efficiency approaches. Though consumers keen to improve their emissions footprint or manage their energy bills may often be indifferent as to whether this is achieved through renewables or efficiency, policy-makers have to be aware of the risk of distorting optimal decision-making, for example by creating incentives which may favour either centralised or local renewable sources or energy efficiency solutions. Technology-specific building codes are one example of this hazard.

While some technologies are tied to specific policy objectives, there are many examples of situations in which renewable energy, energy efficiency and electrification could each contribute to a solution or simultaneously influence the realisation of more than one objective (Figure 7.14). For example, renewable energy with low marginal costs, can reduce short-term energy prices, but at the expense of weakening the price incentive for energy efficiency. In the transport sector, the speed of electrification of passenger transport can affect the cost of meeting biofuels blending mandates. A well-balanced portfolio of efficiency and renewable energy measures can optimise the sizing of distributed energy systems, avoiding additional investments to deal with imbalances, such as electricity storage.

This section focuses on three examples of situations in which the value and interaction of renewables, efficiency and electrification need to be considered together:

- Demand-side response (DSR), which can harness energy demand as a source of flexibility for the integration of variable renewables in electricity supply.
- Industrial heat demand, for which reliance on fossil fuels can be significantly reduced using a blend of solutions, if efficiency, renewables and electrification work together.
- Building energy codes, which risk locking in sub-optimal outcomes, if competing technology options are mandated, rather than incentivised through performance-based metrics.

Figure 7.14 ▷ **Examples of technologies contributing to energy efficiency, renewables or electrification targets**



Renewables, energy efficiency and electrification technologies can have synergies, and need to be considered with a balanced approach to system optimisation

Note: EMS = energy management systems; EVs = electric vehicles; DH = district heating; DSR = demand side response; H_2 = hydrogen; PV = photovoltaic.

7.5.1 Demand-side response: a meeting point for energy efficiency and variable renewables-based electricity

The maximum output of variable renewables, such as wind and solar PV, depends on the amount of wind and sunlight available at a given moment. At high shares of variable renewables, the paradigm for power systems management can change (IEA, 2016a). Traditional grid management prioritises matching supply to shifting demand, with DSR used mainly for planned reductions in load at predictable times of extreme stress on power systems.[15] But as the shares of variable wind and solar power increase, consumers

15. The most common form of DSR involves offering a monetary reward to end-users to reduce or avoid consumption at a given moment, either scheduled or in response to a short-term request. It can work by shifting demand to a time when renewable supplies are more plentiful, an action that can both take advantage of low electricity prices and avoid prices becoming negative. DSR is generally, but not always, facilitated by an intermediary between the market operator and the consumer, such as an independent DSR aggregator or an electricity retailer.

who can rapidly adjust their demand to follow supply become a valuable resource for system operators as a means of avoiding supply disruptions or curtailment of renewable generation. In several markets in Europe and the United States, consumers can already receive payment for various forms of short-duration "fast frequency response" to keep the grid in balance, larger volumes of "load shifting" to respond to changeable weather, or contracts for guaranteed changes to future consumption patterns. While DSR is not a universal solution to the integration challenge of variable renewables, in certain contexts it can be a more cost-effective and climate-friendly measure than building and retaining power plants and electricity storage for only occasional use (IEA, 2016a).

Why energy efficiency and variable renewables need to work together

The potential for DSR depends on the total capacity of all the loads that, at any given moment, can be shifted to a different period of time, or shed entirely. Grid congestion is likely to be most acute at times of peak demand, while oversupply can be an issue around midday in some regions. The lowest cost opportunities at these times are generally found in large commercial and industrial processes that are not highly time-dependent, such as water treatment, heating and cooling, or charging of electric vehicles. Flexible loads can also be identified in the residential sector.[16] The inclusion of connectivity criteria in appliance performance standards is one way to facilitate DSR at a low cost.[17] Arrangements for aggregation and automation are important to permit the DSR potential of households to be harnessed and remunerated despite the low incentive for individuals to actively participate.

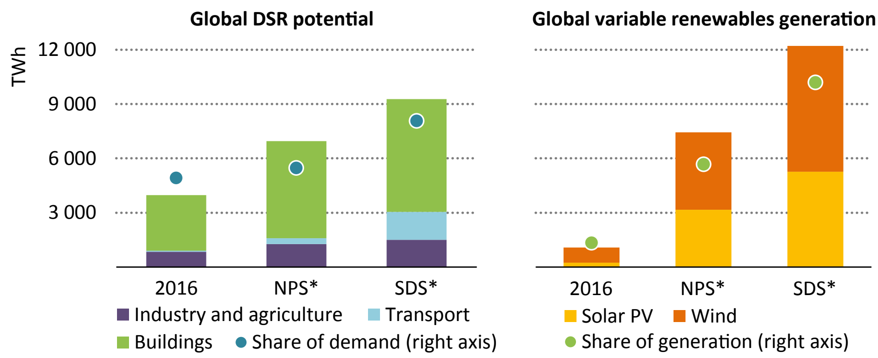
Globally, we assess current theoretical DSR potential to be nearly 4 000 TWh per year, around 15% of total electricity demand. This represents the sum of the flexible loads for each hour of the year, excluding electric vehicles at times when they are expected to be in motion.[18] In the New Policies Scenario, the potential in the buildings sector grows as demand for appliances, electric heating and cooling expand in Asia and Africa. Increasing electrification of heating and transport in advanced economies contributes to rising potential. On the other hand, greater energy efficiency of appliances and building envelopes acts in the opposite direction, slightly reducing DSR potential. Overall, in the New Policies Scenario, DSR potential as a share of total electricity demand grows modestly to 2040 (Figure 7.15).

16. Flexible loads include equipment and appliances whose usage can be partly (or totally) shed or shifted without affecting user behaviour, output or comfort. Examples include major appliances (refrigerators, washing machines and dryers), electric water heaters with storage, and electric boilers and heat pumps for heating purposes. Inflexible loads include equipment that needs to draw power at the time when consumers demand the service, such as ovens, lights, televisions and computers.

17. Connectivity refers to the ability of an appliance, machine, or other device, to send and receive data through digital communication networks and modify activity based on received information.

18. The theoretical DSR potential refers to the aggregate of all flexible loads for a given year, taking into account various parameters such as the ability to remotely shed or control equipment and the extent to which such action is acceptable to end users (IEA, 2016a). It does not correspond to the readily available potential.

Figure 7.15 ▷ DSR potential and generation from variable renewables in the New Policies and Sustainable Development Scenarios



Demand side response becomes an increasingly important source of flexibility supporting the integration of a growing share of generation from variable renewables

Note: NPS* = New Policies Scenario in 2040; SDS* = Sustainable Development Scenario in 2040.

Whereas today's global DSR potential is around three-times higher than electricity generation from solar PV and wind, in the New Policies Scenario this ratio falls to one by 2040. In the Sustainable Development Scenario, variable renewables capacity grows much faster, but DSR potential is still equivalent to over half the generation from variable renewables in 2040, in annual energy terms, though DSR may not be available at critical times. However, only a small share of this potential is currently being used. Tapping this potential is, in part, a policy and market design issue. Policies to facilitate DSR are emerging in a number of regions, while in others, they are still in development (Spotlight).

Not all electricity demand can be shifted automatically in response to price signals. But, in systems that lack flexibility options, policy-makers can still act to increase the share of load that is flexible. Today's energy efficiency policies will mostly avoid electricity demand from flexible loads. In 2016, 57% of flexible loads in residential buildings (which is the largest contributing sector to flexible electricity demand today) were covered by energy efficiency policies whereas the coverage for non-flexible residential loads was only 23%. The current approach could lead to more growth of inflexible, inefficient small appliance loads that reduce the share of flexible demand in overall electricity demand. For example, in the New Policies Scenario, energy efficiency improvements avoid over 560 TWh of energy demand from flexible loads in 2040, but only 270 TWh from inflexible loads, a figure which would be much lower if LEDs were not deployed as fast (Box 7.2). If the additional inflexible demand occurs during mornings or evenings, i.e. outside times of solar output, it further exacerbates the need for flexibility in other loads. In this situation, the value of energy efficiency varies according to the time and flexibility of the demand it avoids, which becomes an additional consideration in the design of energy efficiency policies.

S P O T L I G H T

Tapping DSR potential for variable renewables integration

Today, the enabling environment for DSR varies considerably across jurisdictions. In general, measures to incentivise demand-side response are market-based, pricing the value of reducing load at a given moment, or pricing the value of having load reduction capacity available over a longer period, such as a year:

- Remuneration of direct responses: consumers, retailers or third-party aggregators earn revenue from direct participation in wholesale markets (offering load reduction in lieu of generation) or reduce bills by reacting to dynamic retail pricing;
- Remuneration of available capacity: consumers or third-party aggregators sell a guarantee that a given capacity will be available for curtailment at certain times.

In the case of the latter, a number of electricity markets have capacity market mechanisms that are open to participation from DSR resources, alongside generators, to minimise overall system costs through competition (Table 7.4). In some cases, agreements exist to procure and reward longer term energy efficiency measures that guarantee peak demand reductions (IEA, 2017a).

Table 7.4 ▷ Current status of DSR enablers in various electricity markets

	Wholesale	Ancillary Services	Capacity*	Aggregator	ToU**			RTP***		
					I	C	R	I	C	R
France	🟢	🟡	🟢	🟢	🟢	🟢	🟢	🟢	🟡	🟡
Germany	🔴	🟡	🔴	🔴	🟢	🟡	🟡	🔴	🔴	🔴
UK	🟢	🟢	🟡	🟡	🟢	🟢	🟢	🔴	🔴	🔴
ERCOT	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
CAISO	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🔴	🟢	🟢
PJM	🔴	🟢	🟢	🟢	🟢	🟢	🟢	🔴	🔴	🟢
NYISO	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🔴	🔴	🔴
China	🔴	🔴	🔴	🔴	🟢	🟢	🟡	🔴	🔴	🔴
India	🟡	🔴	🔴	🔴	🔴	🔴	🔴	🔴	🔴	🔴

🟢 Fully implemented; 🟡 Partially implemented or only in some States; 🔴 Not implemented.

*Where no capacity market is present in the jurisdiction, day-ahead reserves and other market products used to guarantee supply are included. **ToU refers to time-of-use pricing. ***RTP refers to real-time pricing, including critical peak pricing where the time and price of peaks is not predetermined. Notes: I, C and R refers respectively to industrial, commercial and residential consumers. ERCOT, CAISO, PJM and NYISO are major electricity markets within the United States.

To date, most end-user participants are large-scale electricity consumers in the industrial or services sectors. On the retail side, the Voluntary Price for Small Consumers in Spain, and dynamic tariffs in Norway and Finland highlight the potential for real-time pricing (RTP) to facilitate DSR. Despite this progress at wholesale and retail levels, a number of markets either do not allow DSR participation or do not allow competition at all, discouraging cost-effective solutions for variable renewables integration.

In the United States, since 2011 the Federal Energy Regulatory Commission has required DSR to be compensated at full market price in wholesale markets. This ruling was tested and upheld in the US Supreme Court in early 2016. New requirements for year-round availability and higher penalties for non-delivery in the PJM market have reduced the extent of contracted DSR capacity for 2020-21 by around 25% compared to the peak in 2015-16. Nonetheless, PJM remains the largest DSR market, with contracts for DSR capacity equivalent to around 5% of peak demand, over 80% of this capacity being provided by independent aggregators (PJM, 2017). The European Commission has outlined proposals to ensure that DSR is not excluded from any relevant electricity markets. In the United Kingdom, 1.4 GW of DSR was contracted (for 2020-21) in the third annual capacity auction in 2016 and an additional dedicated auction in 2017 for turn-down capacity[19], which is considered to require more policy support to develop the market, resulted in 312 MW contracted for 2017-18.

While China has enormous potential for DSR, few steps have been made to develop voluntary DSR capacity to date, though the government is committed to developing DSR by 2020, as part of China's drive to enhance the interaction of electricity supply and demand, using new communications technologies.[20] The emergence of meaningful (non-emergency) DSR in China is reliant on progress in developing efficient electricity markets that reflect the marginal cost of providing electricity.

To capitalise on the full spectrum of DSR potential requires appropriate price signals and the right regulatory framework, in addition to sophisticated information and communication technology for instant communication with a vast array of households, businesses and connected devices. Smart meters and devices, including HVAC (heating, ventilation and cooling) systems and electric vehicles, equipped with load management software are central to these efforts.[21] Underpinning DSR is the capacity for many types of demand to be co-ordinated, so as to respond effectively to price, or other external signals, by changing use patterns. Thus, the benefits of smart meters rely on connected devices and vice versa. However, while smart meter deployment programmes are gathering momentum – with nearly $15 billion spent in 2016 – of the nearly 10 000 models of appliances listed in the US Energy Star Program database, less than 1% have connectivity capability.

19. Turn-down capacity refers to demand-side response capacity contracted to be available for load reduction at given time periods.

20. Highlighted by China's *Guiding Opinions on Promoting the Development of Internet Plus Smart Energy*, published by the National Development and Reform Commission and National Energy Administration in 2016.

21. For more information on the interactions between connectivity enabled technologies and energy systems, see *Digitalization & Energy* (IEA, 2017e).

In addition to having the necessary technology available, realising demand response is dependent on a range of business, market, social and regulatory factors (Table 7.5). Government policy will need to address these issues though a mixture of clear rules (for example for data management) and the creation of effective markets and entrepreneurial environments for new players. Today, the primary limitation to the development of DSR is the lack of sufficient revenue to cover costs and stimulate investment.[22] But there are also concerns about disruption to service availability, over complexity, data privacy and how to persuade households to switch to time based pricing.

Table 7.5 ▷ Realising demand-side response potential

Enabling technologies	Smart meters: enable a bi-directional flow of information. Data analytics and control systems: interpret information and manage flexibility. Smart appliances: automatically respond to external signals, adjusting consumption. Behind the meter generation and storage: increase the flexibility potential of DSR.
Business models	Direct monetisation: dynamic retail pricing - consumers respond to retail price signals. Participation incentives: capacity-based incentive, offered by retailers. Aggregation: third-party aggregation and deployment of flexibility resources. Energy services outsourcing: third-party energy system management services. Distribution optimisation: provide congestion management services to Distribution System Operators.
Market	Wholesale energy markets: bid DSR in lieu of generation. Balancing markets: adjust load up or down to balance system in real-time. Ancillary services: automated DSR provides high-value frequency response services. Capacity markets: currently the most important source of revenue for DSR in many markets.
Benefits	End-users: reduce bills or earn additional revenue. Power system: reduce need for peak generation capacity, enhance grid flexibility. Environmental: limit curtailment, avoid use of carbon-intensive peak generators. Decentralisation: assists grid integration of distributed resources, lowers transmission and distribution costs.
Barriers	Market participation: markets unfavourable or closed to DSR, especially aggregation. Revenue uncertainty: high risk investment due to policy and revenue uncertainty. Quantification of DSR: lack of standards; reliance on a counterfactual consumption baseline to measure, and reward, demand-side response. Perceptions: perceived high complexity and risk of disruption for consumers.
Policy enablers	Market design: create a level playing field and open new and existing markets to DSR. Benchmarks: update standards and building energy codes to facilitate adoption. Regulation: clear legal framework for aggregator-consumer-supplier relationships. Dynamic pricing: establish regulatory framework to facilitate adoption.

22. Investment costs, opportunity costs and variable costs to shifting or shedding demand.

While energy efficiency can, in specific cases, constrain the amount of DSR that can be procured, this factor is expected to be outweighed by the benefits of peak load reduction through energy efficiency. When the peak load is lower, incidences of grid congestion, leading to more fossil-fuel use are fewer. If efficiency measures are directed at sources of peak electricity demand, such as residential heating and cooling, this can reduce the overall need for flexibility and DSR. While more attention needs to be paid to increasing the share of flexible demand, to overcome intra-day imbalances in the power system, energy efficiency also has an important role to play in reducing intra-seasonal demand differences. High performance building envelopes lower overall demand for space heating and cooling, but also reduce the demand volatility resulting from diurnal, weekly and seasonal temperature variations. As an example of the importance of efficiency in reducing overall peak demand, on average a drop in temperature of one degree Celsius in winter in France gives rise to an additional 2.4 GW of demand, due to the reliance on electricity for space heating and low efficiency of the building stock.

If the system value of flexibility is not well-communicated via time- or location-reflective pricing, end-users may trade off in a sub-optimal manner the gains offered by energy efficiency against gains offered by flexibility, or vice versa.

7.5.2 Efficient supply of clean industrial heat

Use of direct renewables for heat in the industry sector grows from 8% of total heat demand in 2016 to 11% in 2040 in the New Policies Scenario, and the share of electricity in industrial heat provision grows from 3.5% to 5%. Over the same period, energy efficiency improvements in the industry sector lead to more avoided energy demand than in the buildings and transport sectors combined. However, across industry much potential remains for reducing direct and indirect CO_2 emissions without increasing energy costs, as well as limiting air pollution, increasing energy security and increasing the flexibility of the energy system. The timing and nature of efficiency, renewables and electrification measures in the industry sector can be co-ordinated in pursuit of these goals.

Industrial processes use heat at a variety of temperatures, depending on the nature of the process. Fossil fuels can be more easily displaced by alternative heat sources for low-temperature applications. Medium to higher temperature heat can be provided by renewables, under certain conditions. We estimate that half of industrial heat demand today is high temperature at 400 °C or above, with the other half evenly split between medium temperature (100-400 °C) and low temperature (below 100 °C). The iron and steel subsector accounts for a large part of total high-temperature heat demand: blast furnace pig iron production requires temperatures up to 1 300 °C. Temperatures of around 1 400 °C are necessary for cement production, while the requirement for aluminium smelting is 1 000 °C. Table 7.6 gives some examples of low- and medium-temperature processes, including in the food and beverage, textile and agro-industrial subsectors. Some low- and medium-temperature heat is also required in energy-intensive sectors, such as for alumina refining.

Table 7.6 ▷ Common industrial low- and medium-temperature processes

Process	Temperatures (°C)	Subsectors
Washing	40-90	Food and beverage, agro-industry, textiles.
Cooking	60-100	Food and beverage, paper.
Pasteurisation	60-80	Food and beverage.
Sterilisation	60-90	Food and beverage.
	100-120	Agro-industry.
Distillation	140-150	Food and beverage, plastics, pharmaceuticals.
Drying	60-100	Wood, paper.
	100-130	Textiles.
	120-200	Agro-industry, plastics.
Bleaching	60-100	Textiles.
	130-150	Paper.
Sanitary hot water	40-80	Food and beverage, pharmaceuticals, mining.
Boiler feed water	60-90	Agro-industry, paper, textiles, chemicals.

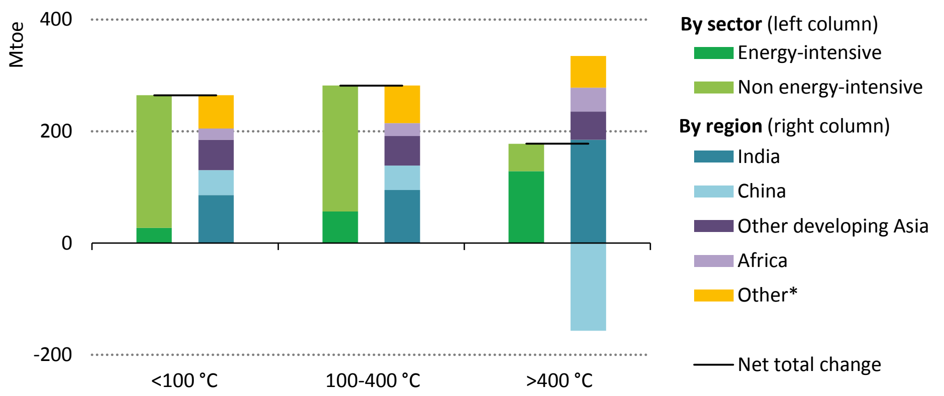
Sources: Mekhilef, Saidur and Safari (2011); Kalogirou (2003); IEA analysis.

Outlook for industrial heat

Industrial heat demand at all temperature levels increases in the New Policies Scenario, though low- and medium-temperature heat needs grow most (Figure 7.16). Growth in heat demand below 200 °C accounts for two-thirds of the total increase to 2040. Non energy-intensive industry accounts for 85% of the growth in this heat demand temperature range, with most of the remaining growth in the chemicals and petrochemicals industry. Regionally, in the New Policies Scenario, about two-thirds of the total increase in heat demand for industry to 2040, and 70% of the low-temperature growth occur in developing Asia. This is driven by the transition to a progressively higher share of light industry and a lower share of heavy industry. India accounts for almost half of the total growth in industrial low-temperature heat demand in developing Asia, followed by China. For high-temperature heat, demand decreases in China, as its iron and steel production shrinks, but India's demand for steel and cement is a significant contributor to the overall global rise in demand. In the New Policies Scenario, high-temperature heat demand in the European Union, Japan and Korea declines.

The share of electricity in heat supply increases by 2040, mainly as a result of economic and technical considerations rather than policy, which currently does not widely support electrification in industry. While electric heat supply is common in many small industrial settings (e.g. for hot sanitary water or cooking), the anticipated growth areas in the New Policies Scenario are heat pumps for low- and medium-temperature heat and electric arc furnaces for high-temperature heat for steel production. Some electrification technologies also have the complimentary advantage of improving energy efficiency, potentially lowering energy bills. The most efficient are heat pumps, which can have a coefficient of performance (COP) of more than 4, depending on the temperature required and operating conditions.[23] When the full cycle, including fuel conversion and electricity generation, is considered, some of the gains are offset, especially at higher temperature levels where the COP is typically lower. Heat pumps alone lead to the avoidance of 90 Mtoe of energy demand, or 3% of total industrial heat demand in 2040. In Japan and Korea, heat pump deployment raises the average conversion efficiency for heat supply in non energy-intensive sectors to around 100%. Heat pumps can supply heat between 60 °C and 100 °C for a levelised cost of around $60 per megawatt-hour (MWh) in Japan in 2025, whereas heat from natural gas boilers costs around $80/MWh. Electrification using heat pumps can reduce CO_2 emissions, though the magnitude of the savings depends on the power supply mix.

Figure 7.16 ▷ Growth in global industrial heat demand by temperature level in the New Policies Scenario, 2016-2040



Heat demand for all temperature levels increases worldwide, low-temperature needs are driven by the non energy-intensive industries

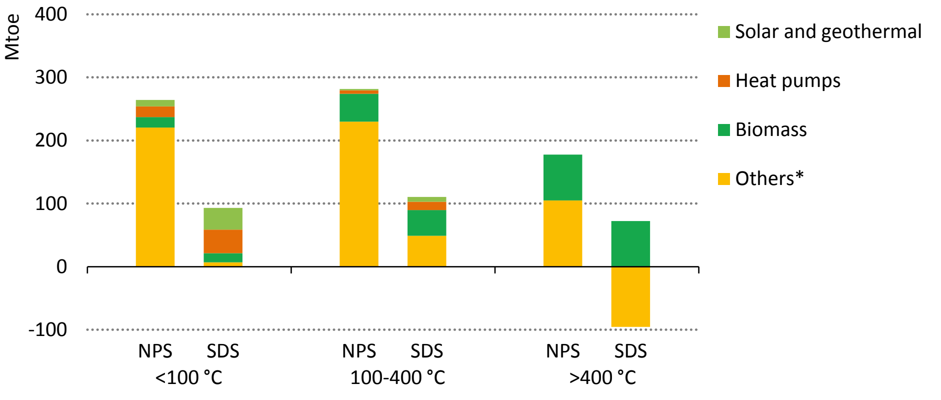
* Net change in heat demand growth from other regions. Notes: Decreasing heat demand in some regions offsets increases in other regions. Low-temperature is below 100 °C, medium-temperature range is between 100 °C and 400 °C and high temperature is above 400 °C.

Among renewables, bioenergy-based heating can be attractive for regions with favourable resource profiles, such as northern Europe, Brazil, sub-Saharan Africa and developing Asia. It is especially appropriate for high-temperature applications that are otherwise hard to decarbonise. But if the resource base is constrained, then industrial heat may have to compete for biomass with non-energy uses, such as chemical feedstocks and wood for construction, as well as with other energy applications, such as power generation and biofuels for transport. Bioenergy consumption in the industry sector grows by 70% by 2040 in the New Policies Scenario, as resources can be locally competitive and are particularly

23. A COP of 4 means that for each unit of electrical energy supplied, four units of heat energy are produced.

suited as a low-carbon option for some sectors, such as cement, pulp and paper, food and beverage or textiles (Figure 7.17).[24] Direct use of geothermal energy is a low-cost option for industry where resources are sufficient to match heat demand. Globally, the use of geothermal heat in industry grows nearly ten-fold by 2040, but it does not rise above 0.1% of total industrial heat demand. This reflects the fact that geothermal potential is limited due to its site-specific nature and that high-temperature geothermal resources are often prioritised for electricity generation.

Figure 7.17 ▷ Change in global industrial heat supply mix by temperature level by scenario, 2016-2040



New and renewable energy technologies address the low-temperature needs and even exceed conventional energy sources in the Sustainable Development Scenario

* Other fuels include conventional fossil fuels and direct heat supply. Note: NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

Solar thermal makes strong inroads in regions where low-temperature heat demand grows most strongly. In 2040, about half of the global low-temperature heat supplied by solar in the non energy-intensive sectors, such as food and beverage, textile or agro-industries, is used in developing Asia. The chemical subsector can make good use of low-temperature solar heat and represents around 20% of total solar heat consumption in 2040 in the New Policies Scenario, though its reliance on solar heat remains small compared to its overall heat demand. In general, however, solar thermal is not widely deployed in the industry sector in the New Policies Scenario, even in regions with high solar insolation, such as the Middle East and North Africa, due to a lack of policy support, less developed supply chains and the availability of cheaper alternatives. In Japan, new solar thermal capacity installed in non energy-intensive industries in 2030 is about half that of heat pumps, whose average levelised cost of low-temperature heat production is lower.

24. See Chapter 11 of the *WEO-2016* for a discussion of bioenergy use and competitiveness in the industry sector.

Deployment of heat pumps and other heat supply energy efficiency measures help increase the average efficiency of heat supply globally by four percentage points, to approach 90% by 2040. Increasing end-use energy efficiency also reduces heat demand growth. End-use measures include the recovery of excess heat for lower temperature heat applications, which further improves energy efficiency at the site level.

The high potential of these approaches is demonstrated in the Sustainable Development Scenario, in which there is a net decline of fossil-fuel-based heat supply in industry. Heat pumps, solar thermal and geothermal displace fossil fuels for the low-temperature needs, while bioenergy is deployed for high-temperature needs. By far the greatest growth in low-temperature heat demand occurs in India, mostly due to the strong development of non energy-intensive industries: low-temperature heat supply costs are more than 20% lower in the Sustainable Development Scenario than in the New Policies Scenario. Additional investment and expenditure of close to $2 billion in 2040 on solar thermal, geothermal and heat pump deployment in India in low-temperature applications is offset by $15 billion of savings on low-temperature heat production from renewables and energy efficiency deployment, relative to the New Policies Scenario.

Policy implications

If policy support is well designed and technology is deployed where it is the most economic, the deployment of energy-efficient and renewable energy technologies can cost effectively limit the use of fossil fuels. The best outcomes will be realised if efficiency and renewable energy options are considered as complementary and, where support is justified, policies provide equivalent levels of support. Allocating capital to new energy assets, such as heat pumps or solar water heaters, is a challenge for industrial users and choices can sometimes reflect the balance sheet and interests of an equipment supplier, rather than the optimal technology. Non-economic barriers must be addressed, and policy co-ordinated at various levels, due to the importance of local governance in industrial and renewable energy decision-making. Two examples of managing these trade-offs are Sweden's heat-mapping exercise and projects at the Göss Brewery in Austria (Box 7.5).

In Sweden, integrated heat planning has been undertaken to help policy-makers decide between various heat supply options (IEA, 2016b); (Liljeblad, Jansson and Noghlgren, 2015). Bioenergy meets most of Sweden's industrial heat demand, largely due to the dominance of the pulp and paper subsector, which generates combustible by-products. Network solutions have been identified as being of particular benefit, but they need targeted multi-year planning. A district heating business model – OpenDHC – has been established whereby excess heat, including heat from data centres, can be valued by feeding it into the heat network, along with heat from combined heat and power (CHP) plants and industrial heat pumps. By enabling industrial sites to act as both suppliers and consumers – a concept with which electricity grids are just coming to terms – both energy efficiency, including reducing heat losses, and renewable heat supplies can be appropriately valued in the heat market.

Box 7.5 ▷ Reaching carbon neutrality in a brewery

In 2003, the Göss Brewery, an Austrian subsidiary of Heineken, initiated a project to switch to renewable energy. By 2010, the objective had been re-defined as the achievement of full carbon neutrality. This was achieved in 2016. The impetus came from an energy savings programme that looked at all options, regardless of cost. Following an in-depth analysis of demand patterns, energy losses and renewable supply options, the brewery implemented the following measures:

- 100% of electricity needs from renewables, contracted from the grid.
- Refurbishments to recover 90% of identified waste heat to use as process heat.
- Biogas use from a wastewater treatment plant, displacing over 10% of gas use.
- Purchase of 75-90 °C hot water from a sawmill, displacing one-third of gas use.
- Installation of a 1 MW solar thermal plant and of heat exchange technology to use 80 to 100 °C hot water rather than steam in the mashing process, displacing around 5% of gas consumption.
- In-situ production of biogas in a spent grain fermentation tank, for use in a steam boiler and combined heat and power unit to provide 50% of the brewery's total energy needs, including electricity.

The sequencing of the measures was important, as initial investments in efficiency improved the attractiveness of subsequent investments in renewables: a higher share of demand could be covered at a lower investment cost.[25]

7.5.3 Expanding building energy codes to cover renewables

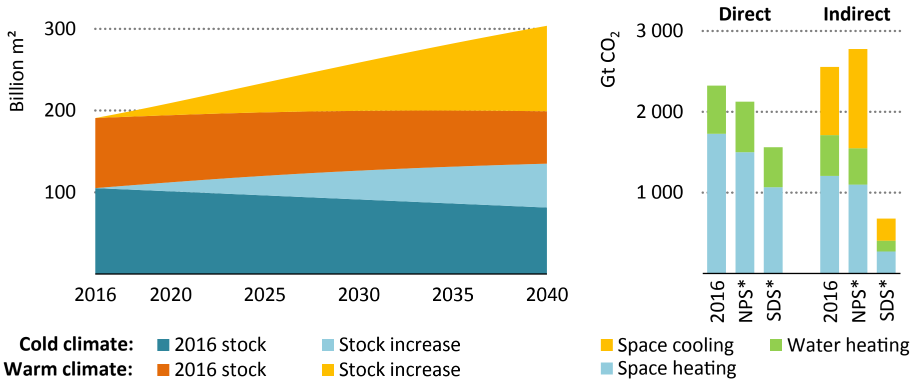
Today, space heating and cooling makes up almost half of the energy demand in buildings, while water heating represents 16% (excluding the traditional use of solid biomass). These end-uses are responsible for 80% of the direct CO_2 emissions and almost half of the indirect CO_2 emissions from buildings. These facts make building energy performance standards ("building energy codes") of high importance in energy policy.

Building energy codes have typically focused on energy efficiency measures but, in a number of countries, they now require both specific levels of energy efficiency and a defined contribution from renewables, either solar PV or renewables-based heat. If they are not well designed, energy intensity targets in building codes may not deliver the best solutions in terms of CO_2 emissions, while renewable targets for buildings may lead to low-cost energy efficiency options being overlooked. In the former case, for example, more efficient gas boilers might replace electric heating, but exclude lower carbon renewables. In the latter case, investment in more solar PV, bioenergy or solar thermal capacity might exceed what the building would require if low-cost efficiency measures were implemented. Physical space for supplying renewables, such as solar PV, can be at a premium in urban

25. The project benefited from European Union funding.

areas and biomass is a precious resource in many countries: energy efficiency helps minimise supply requirements. There is also a risk that tightening building standards too far can generate excessive investment for insulation, while other options, such as heat pumps using renewables-based electricity could be cheaper on a total system cost basis.

Figure 7.18 ▷ Floor area in residential buildings and CO_2 emissions related to space conditioning and water heating in the New Policies and Sustainable Development Scenarios



More than 50% of the residential floor area in 2040 has yet to be built, highlighting the importance of ambitious building energy codes for CO_2 emissions reductions

Note: NPS* = New Policies Scenario in 2040; SDS* = Sustainable Development Scenario in 2040.

Around 60 countries have established building energy codes and around half of these are mandatory at the national level for both residential and non-residential buildings (IEA, 2017f).[26] As more than half of the expected floor area in 2040 has yet to be built, there is a great opportunity for the sector to reduce energy demand and related-CO_2 emissions by expanding the coverage and stringency of building energy codes for new construction. This is especially the case in countries with warm climates, such as India, Indonesia and countries in Africa, where most consumption in 2040 will occur in new buildings (Figure 7.18), located, for the most part, in urban areas. The stringency and enforcement of the building energy codes applied to the rapidly growing urban building stock in these countries will be of global importance, especially as it is the indirect emissions from higher cooling demand that drive an increase in total building-related emissions in the New Policies Scenario. Today, less than 15% of countries in warm climates have building energy codes, and the vast majority of these codes remain voluntary or only cover part of the sector. The

26. Additional countries have mandatory building energy codes in place for specific building types or at a sub-national level of jurisdiction (provincial, state, city). Performance labelling of buildings (giving an assessment of energy use and greenhouse-gas performance) is a complementary tool that increases awareness of energy codes and potential savings.

relative competitiveness of different renewable and energy efficiency solutions (including those for district cooling) varies on a case-by-case basis depending on the electricity mix and future cooling demand. In countries with colder climates, such as North America, the European Union and China, most of the 2040 building stock already exists and a focus on refurbishments will be more telling.

Some countries have already developed, or are currently developing, building energy codes that include both energy efficiency and renewable elements. In South Africa the national building regulations require that the building envelope meets certain thermal efficiency levels. In addition, 50% of the hot water demand must come from renewable sources (such as solar thermal or heat pumps) or heat recovery. Similarly, in the European Union, many countries already have such codes. These will become more stringent, as the energy requirements of all new buildings will need to be low enough from 2020 to be supplied cost effectively by low-carbon sources. Many financial incentive programmes for building energy refurbishments include support for both energy efficiency and renewables, including France's Crédit d'impôt, Andalucia's Construcción Sostenible and Germany's Energieeffizient sanieren schemes. India's Energy Conservation Building Code 2017 is an example of a recent code that includes renewable energy requirements alongside energy efficiency (Box 7.6). However, some countries have failed to achieve effective enforcement of building codes and new steps are needed to overcome this.

Policies included in the New Policies Scenario help to lower energy demand and buildings-related CO_2 emissions growth from space heating and cooling, and water heating. In this scenario, energy efficiency measures help to avoid around 360 Mtoe, or one-quarter, of space heating and cooling energy demand by 2040. However, these services together still account for almost 60% of energy demand in buildings in 2040 as hot and humid climates in developing economies make space cooling desirable and demand for cooling purposes, in particular, mounts. In contrast, the slight growth projected in space heating energy requirements by 2040 can be entirely met by renewable energy.

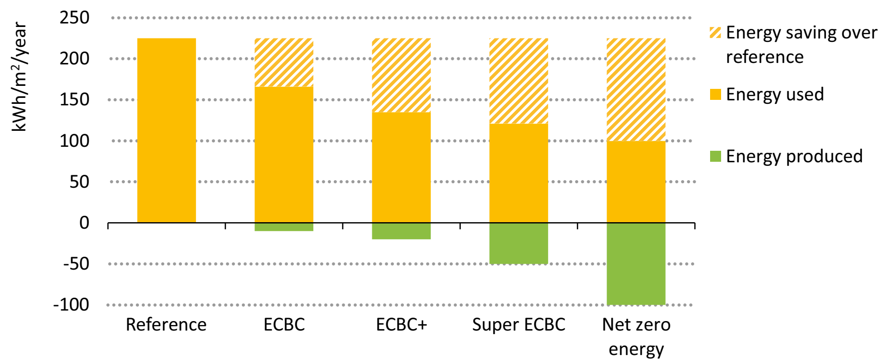
The Sustainable Development Scenario indicates what could be achieved in terms of energy intensity reductions and adoption of renewables for space heating and cooling. It achieves higher synergy between demand reduction, direct renewables supply and indirect renewables use. The turnover of fossil-fuel boilers and their replacement by renewables-based heaters is much faster than in the New Policies Scenario. The energy intensity of space heating and cooling in residential buildings in cold-climate countries declines by around 30% on average by 2040, compared to around 10% in the New Policies Scenario. In warm-climate countries, additional policies for insulation and higher shares of renewables enable most advanced economies and many developing economies to reduce energy intensity, even though households install space cooling as full access to electricity is reached by 2030 in all regions. By contrast, in the New Policies Scenario, income growth and the higher ownership of appliances and cooling systems leads to rising energy intensity in many Asian and African countries.

Box 7.6 ▷ New building energy codes in India

In the past ten years, India has experienced an unprecedented construction boom, and it is expected to add 32 billion square metres of floor space by 2040. Energy consumption in buildings in India increases at a rate of almost 4% per year in the New Policies Scenario, driven by higher air conditioning use and appliance ownership. Published in June 2017, India's Energy Conservation Building Code, has been developed to help curb this high rate of energy growth, which puts pressure on the power sector in relation to its targets for energy access, pollution and clean energy. Although they are voluntary, the codes were developed in consultation with state bodies and construction firms. They apply to buildings using more than 100 kilowatts (kW). They envisage building designs that minimise additional energy needs for heating and cooling, have efficient lighting and comfort control technologies, and renewable energy systems. The standards set are a considerable step up from previous requirements.

A notable innovation of the new codes is a requirement to ensure that buildings are designed in ways that facilitate subsequent incorporation of solar heating (to provide at least 20% of the total hot water needs) and solar electricity systems. Three different performance levels are stipulated, with the higher levels requiring lower energy demand and higher renewable shares (Figure 7.19).

Figure 7.19 ▷ Building energy performance levels in India's Energy Conservation Building Code (ECBC)



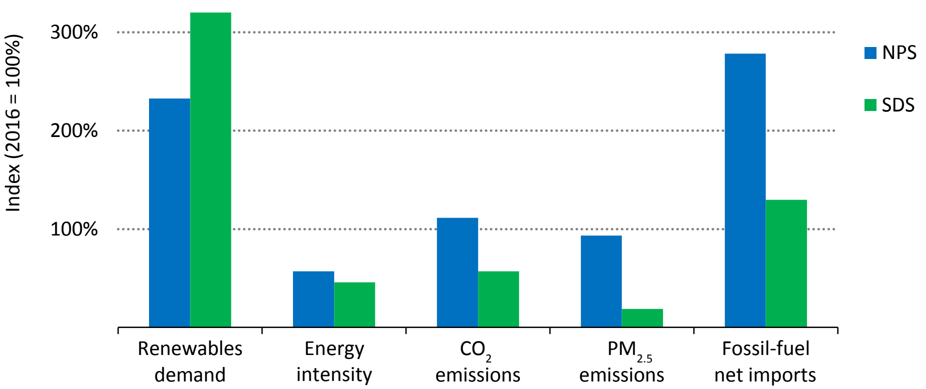
ECBC-compliant buildings achieve energy savings of at least 25%

The Prabha Bhawan building at the Malaviya National Institute of Technology Jaipur, Rajasthan, is an example of the type of building the new code is designed to encourage. It has a central courtyard that increases the penetration of natural light and reduces indoor lighting and vertical fins adjacent to window fixtures to reduce the direct sun that heats the building. The roof supports inverted clay pots as air pockets that provide insulation and solar PV generates around 307 MWh per year.

7.5.4 The multiple benefits of a joint approach

As described, in the New Policies Scenario, the global energy system makes significant strides in terms of managing energy demand, CO_2 emissions and local pollution. The avoidance of energy demand, due to efficiency gains, is rewarded in terms of avoided energy expenditure, higher levels of energy security and avoided investments in new energy supply assets. Reduced fossil-fuel use, stemming from energy efficiency and renewable energy, delivers lower GHG emissions, lower fuel import bills for importing countries, better buildings, reduced air pollution and associated health improvements. The Sustainable Development Scenario delivers even more (Figure 7.20). Energy efficiency and renewable energy play almost equal roles in reducing CO_2 emissions by more than 13 gigatonnes of CO_2 (Gt CO_2) despite rising energy service demand (Figure 7.21).[27] Furthermore, two million fewer people than today die prematurely in 2040 from household air pollution, and compared to the New Policies Scenario 1.5 million fewer people die prematurely, a 35% reduction (see Chapter 3). These multiple benefits can be realised only through concerted and co-ordinated policy action.

Figure 7.20 ▷ Change in key indicators in the New Policies and Sustainable Development Scenarios in 2040 relative to 2016



A combined energy efficiency and renewables approach delivers multiple benefits at lower energy cost

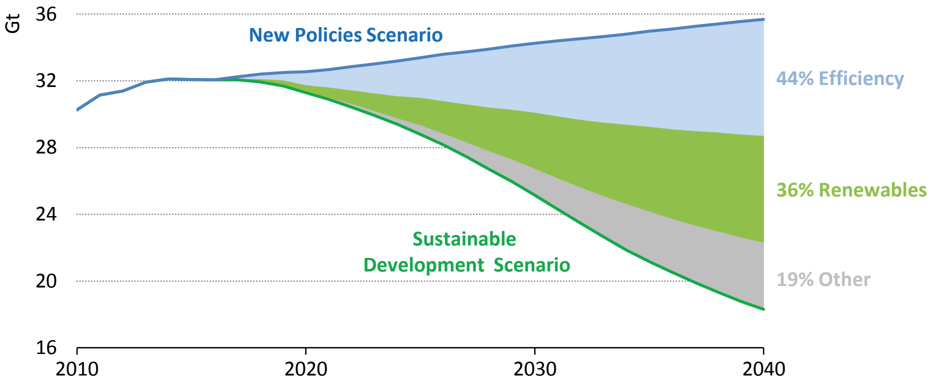
Note: NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

Total investment in the Sustainable Development Scenario is around 15% higher relative to the New Policies Scenario, but is redistributed among the sectors: in the New Policies Scenario energy efficiency and renewables account for around 40% of cumulative investments during the projection period, but this figure is 54% in the Sustainable

27. By comparison, efficiency leads to more avoided emissions than renewables in the New Policies Scenario, largely because of improved fuel economy in transport under current and existing policies.

Development Scenario. Higher investment in energy efficiency improvements and renewable deployment also have a direct impact on households expenditures: even though end-user prices are in many instances higher in the Sustainable Development Scenario (for example, due to carbon pricing, and the phase-out of fossil-fuel subsidies), household bills are 2% lower on average by 2040, compared to the New Policies Scenario, reflecting lower energy demand. Lower fossil-fuel demand also has broader implications: by deploying renewables and improving energy efficiency, net importing countries lower their fossil-fuel imports, increasing their reliance on domestic resources and so improving energy security.

Figure 7.21 ▷ Global energy-related CO_2 emissions abatement and key contributions in the Sustainable Development Scenario



Energy efficiency and renewables are the two key abatement measures in the New Policies and Sustainable Development Scenarios

Notes: Other refers to carbon capture and storage, nuclear, and fuel switching. The shares on the right-hand side of the graph represent the cumulative contributions by measures.

Policy implications

Not only are energy efficiency and renewable energy technologies widely deployed in the Sustainable Development Scenario, they are also highly co-ordinated. As detailed in this chapter, realising the best outcomes requires a holistic view, good policy design and rigorous implementation, all of which depend more on regional circumstances and other local considerations than traditional areas of energy policy. First and foremost, advantage should be taken of the numerous recent examples of good practice in policy design. In energy efficiency, this includes the development of minimum energy performance standards that lock in continuous improvements and establish global markets for efficient goods. It also includes integrated transport planning and market-based measures that stimulate new solutions to meet targets, such as tradeable energy savings certificates, auctions and participation in capacity mechanisms, as well as the removal of end-user fuel subsidies. Progress in renewables-based electricity requires the further development of risk-management tools and auctions, based on locational and temporal pricing wherever possible. Increasingly, it also requires market measures that reward solutions that deliver the flexibility required for integrating variable generation at lowest cost and environmental impact. In renewables for heat and transport, it includes the establishment of clear sustainability criteria and flexible approaches to direct and indirect use of renewables to raise the share of renewables.

Moving beyond independent approaches to policy-making for energy efficiency and renewables gives rise to an additional set of considerations. These mostly relate to ensuring that policies exploit synergies and incentivise desirable outcomes rather than specific technologies. In this light it is important for policy makers to consider the following general guidelines:

- Keep in mind the end goal, while also addressing the short- and long-term barriers to the adoption of renewable energy and energy efficiency.
- Ensure the synergies between energy efficiency and renewables are maximised and the risk of policies working against each other is avoided, as the scale of deployment grows.
- Provide a flexible policy framework, allowing markets and regulations to adapt to changing dynamics in the energy sector as digitalisation of energy systems, and other trends, enable the emergence of new business models and solutions.

Building on the cases presented in this chapter, a more detailed set of policy recommendations might include:

- Create an overarching policy framework to co-ordinate decision-making. A common view on climate, air pollution, energy security and energy access objectives is essential for holistically evaluating the impact of policies, new technologies, market developments and societal trends. This is of particular importance when different policy measures – such as carbon pricing, subsidies, performance standards – interact to influence values in related markets.
- Create markets or incentives that recognise the temporal value of energy efficiency and renewable energy measures. Shifting or eliminating energy demand at times of peak load will have greater value when transferred to times of higher levels of variable renewable generation. This applies equally to self-consumption of local renewable energy. The means by which utilities and consumers can measure and monetise this value are becoming widely available.
- Link building codes to outcomes rather than technologies. To ensure that zero net energy buildings become widely available to property developers in all countries, the construction and refurbishment industries need the skills and incentives to respond flexibly to local renewable resources, technology prices and behavioural factors. Effective policy will account for the relative availability and costs of direct and indirect renewable energy supply.

- Place demand-side response on a level playing field with other flexibility options. As electricity markets develop market rules for rewarding DSR aggregation and participation, best practices can be disseminated globally. Facilitating technologies will be important too; in addition to smart meters, this includes the incorporation of connectivity criteria and flexibility requirements into energy performance standards.

PART B
SPECIAL FOCUS ON NATURAL GAS

PREFACE

Part B of this *WEO* (Chapters 8-11) focuses on natural gas, the only fossil fuel that sees growth in all the main scenarios examined in this *Outlook*.

Chapter 8 presents a summary of the main scenarios, covering key demand and supply trends as well as trade and investment flows. It includes a focus on the outlook for coalbed methane and on the prospects for liquefied natural gas (LNG) shipping.

In Chapter 9 we examine the structural transformation in the gas market that is being spurred by the rise of LNG, in particular from the United States, in the direction of a more interconnected and globalised network. It considers the potential implications of this transition for pricing, contracts, affordability, investment and security of supply.

Chapter 10 assesses the environmental case for natural gas, the lower combustion emissions of natural gas versus other fossil fuels (both for CO_2 and the pollutants that cause poor air quality), the climate risks associated with direct methane emissions to the atmosphere, and the approaches, costs and benefits of action to reduce methane emissions.

Chapter 11 explores in detail the role of gas in the clean energy transition and how this plays out in different sectors and countries, and how it evolves over time. It concludes with a review of the possibilities to decarbonise gas supply itself.

Outlook for natural gas

A fuel for all seasons?

Highlights

- In the New Policies Scenario, global natural gas use increases by 45% in the coming 25 years, with industry accounting for a third of the growth (up from less than 20% over the last 25 years), slightly ahead of the additional gas used for power generation. Developing countries in Asia, Africa, Latin America and the Middle East account for 80% of the increase in global consumption. The tilt towards industrial gas use is particularly pronounced in the next ten years. In the second-half of the *Outlook* period, gas demand in the power sector picks up again as a move away from coal in some markets creates more room for gas to grow, alongside renewables.
- With projected growth of 1.6% per year, prospects for gas are good in the New Policies Scenario, but a return to the growth rate of 2.3% seen in the previous 25 years is not in the cards. Depending on the circumstances, renewables can facilitate or curb gas demand growth. In addition, in many gas-importing countries, especially in Asia, beating coal on cost alone is a tall order, highlighting the importance of a supportive policy environment if gas is to thrive.
- The United States adds some 300 bcm to global gas supplies over the next 25 years, more than any other country, followed by China (200 bcm), Russia and Iran (both around 145 bcm). Unconventional gas – shale gas in particular – accounts for over half of the incremental production worldwide over the period to 2040. North America continues to lead the unconventional gas revolution, but China, Argentina and Australia play increasingly important roles too.
- Long-distance trade grows by three-quarters to 1 230 bcm in 2040. The bulk of the expansion comes from LNG, which increases its share in trade from 39% in 2016 to some 60% by 2040. With the main exception of new pipelines to China from Russia and Turkmenistan, which have strong financial and political backing, complex large cross-border pipelines find it hard to advance in a world with ample supplies of LNG.
- With 140 bcm of LNG capacity still under construction, gas markets remain well supplied for the next few years. By the mid-2020s, however, market over-capacity is absorbed by import growth. Investment in new capacity therefore is needed from 2020 onwards, and much of the new supply comes from low-cost sources of gas in the United States, Russia and Qatar.
- Although the European Union remains the largest importer of gas, the Asia Pacific region accounts for some 85% of the growth in net imports, underpinning a shift in trade flows from the Atlantic basin to Asia. Much of the import growth in Asia comes from new importers in South and Southeast Asia, further strengthening the diversity and globalisation of gas markets.

8.1 Recent market and policy developments

The global gas market has been buffeted by the twin effects of a massive wave of investment in new liquefied natural gas (LNG) supply and a slowdown in demand growth that pushed growth in global gas consumption down to 1.3% per year between 2010 and 2015, compared with annual growth of 2.8% in the first decade of the 2000s. Together with lower oil prices, which have brought down oil-indexed gas prices in recent years, this has led to a marked drop in gas prices around the world. The International Gas Union estimates that the average global wholesale price of gas fell to $3.35 per million British thermal units (MBtu) in 2016 – the lowest level ever recorded in their surveys, which began in 2005.

The structural oversupply in the gas market is set to persist in the coming years as nearly 140 bcm of liquefaction capacity currently under construction becomes operational, mostly in the United States and Australia. Qatar, the world's largest exporter of LNG, meanwhile lifted its self-imposed development moratorium in early 2017, providing the basis for renewed expansion of its own export capacity. These developments have already started to reshape gas markets and will continue to do so in the future. Chapter 9 addresses the question of whether they amount to a new gas market order. However, the ample availability of gas does not mean that risks to security of supply have disappeared, as demonstrated for instance by current problems with LNG plants in Yemen, Nigeria and Algeria, and by the recent standoff between Qatar and its neighbours.

On the demand side, latest data suggest that the long-awaited demand response to lower gas prices may have finally started to happen. Global gas use is estimated to have grown by 2.6% in 2016, a marked rise over recent demand growth rates, and preliminary demand data for the first months of 2017 suggest continued momentum, notably in China. It is not yet clear whether gas demand has turned a corner, but the gas industry has certainly become more inventive: a lot of the growth in 2016 came from a multitude of relatively new and small LNG importing countries like Egypt, Pakistan and Jordan. The number of countries importing LNG has risen from 15 in 2005 to around 40 as of mid-2017. But the year also saw some remarkable developments in mature gas markets. In the United States, for the first time ever, more electricity was generated from gas than from coal in 2016. Even the European Union, where gas has had a dismal few years, saw a rise in gas use for power generation. The reasons for greater gas use varied from country to country: in the United Kingdom, it was driven by coal-to-gas switching underpinned by an administered carbon price floor. In a similar vein, Korea's new president has outlined a new energy policy programme that envisages an expanded role for gas in power generation at the expense of coal (mostly for air quality reasons) and nuclear.

Since it is relatively clean and flexible, natural gas is often seen as a fuel that can help to reduce the carbon intensity of the energy system and also contribute to improving air quality. It can achieve rapid environmental benefits when it replaces coal or oil, as demonstrated for instance by China's replacement of small coal boilers with gas boilers in industry and for heating of buildings. However, few countries have specifically mentioned gas in their Nationally Determined Contributions as part of the Paris Agreement and this raises the question what role gas might play in the transition to a low-carbon energy world (examined in Chapter 11). In this context, methane emissions from the production and transport of natural gas are an important challenge (explored in detail in Chapter 10).

Our projections suggest that gas is set to perform much better than other fossil fuels over the coming decades. However, the role of gas varies widely across different countries and regions: in this special focus on natural gas, we identify the sectors that are strongholds of gas use as well as those where gas faces an uphill battle for new consumers. The competitive landscape is changing rapidly, and gas faces challenges from coal in many markets, and from renewables in others: depending on circumstances and sectors, new low-carbon technologies can be both threats to, and enablers of, gas demand growth. On the supply side, we take a detailed look at where the additional gas might come from and how it reaches burner tips, boilers, turbines and chemical plants around the world. In addition, we examine what it might take to reassure not just policy-makers, but also an occasionally sceptical public, that gas can have a rightful place in the future of global energy.

This opening chapter summarises the overarching trends for gas demand and supply in the period to 2040 and provides the framework for the topical discussions in the following three chapters. As the analysis demonstrates, there are good reasons to be upbeat about the prospects of natural gas – its relative abundance, flexibility and environmental advantages make it a good fit for the needs of the future energy system. At the same time, there are many uncertainties and some potential pitfalls.

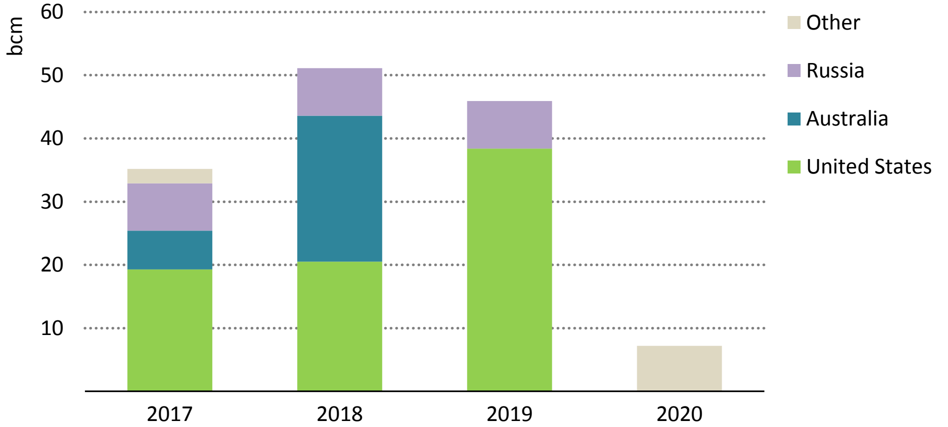
8.2 Trends to 2040 by scenario

8.2.1 Market dynamics to 2025

In the New Policies Scenario, the next ten years are characterised by the gradual rebalancing of the gas market. The United States, the world's largest gas producer, increases production more than any other country over this period, accounting for 40% of global output growth. US gas exports become central to the developing global gas market: over half of nearly 140 billion cubic metres (bcm) of global liquefaction capacity currently under construction is in the United States and it becomes the largest LNG exporting country by the mid-2020s. Major additions of liquefaction capacity also come from four Australian projects and Novatek's Yamal LNG project in Russia, and further additions from new liquefaction plants that Indonesia, Malaysia and Cameroon are currently in the process of building (Figure 8.1). These developments in the LNG market are complemented by two long-awaited new pipeline corridors anticipated to start operation in the next five years: an expanded connection between Azerbaijan, Turkey and European Union countries via the TANAP and TAP pipelines, and the "Power of Siberia" pipeline that links Russian gas fields to the Chinese market (IEA, 2017). Turkstream 1, a pipeline aimed at supplying Turkey with Russian gas via the Black Sea, has also just started construction.

Gas consumers are looking to benefit from low gas prices and procure additional volumes of LNG: there are currently over 115 bcm of new regasification capacity under construction, nearly three-quarters of which is in Asia. Our main scenario projects global gas consumption growth of 1.5% per year, on average, to 2025, considerably faster than growth for oil (0.8%) and coal (0.2%). China is the primary engine of growth, accounting for 35% of incremental gas use in the next ten years, followed by the Middle East with 17%. Gas demand is expected to fall in Japan – the largest LNG import market – in the period to 2025, but there are significant uncertainties over this trajectory related to decisions about the restarting of Japan's nuclear reactor fleet. In terms of sectoral contributions to global natural gas demand growth, industry is the frontrunner, using around 40% of the additional gas in the period to 2025, followed by the power and the buildings sector (both 18%).

Figure 8.1 ▷ Liquefaction capacity currently under construction by key countries and year of first commercial operation



Nearly 140 bcm of liquefaction capacity is under construction and slated to come online over the next few years, more than half of which is in the United States

Notes: The figure shows first year of commercial operation of LNG plants and name-plate capacity, but utilisation of plants can be expected to ramp up gradually over time. For reasons of consistency with IEA (2017), plants that had already come online in the first-half of 2017 are not shown.

Source: IEA analysis based on Cedigaz (2017).

In the light of the current low gas prices, investment activity in new liquefaction capacity has ground to a halt. With a few exceptions like the Coral floating liquefied natural gas (FLNG) vessel in Mozambique, on which a final investment decision was taken in June 2017, and the anticipated Fortuna project off the coast of Equatorial Guinea, the flow of new LNG projects has dried up. Our projections suggest that demand growth will have absorbed the supply overhang by the mid-2020s, creating a need for timely new investment if market tightening and volatility are to be avoided. Factoring in lead times, a soft landing for gas markets in the 2020s requires new investment decisions – even for brownfields and smaller projects – to be taken before 2020. However, as discussed in detail in the next chapter, managing the volume and price risks for these new investments is no simple task.

8.2.2 Long-term scenarios to 2040

In the New Policies Scenario, our main scenario, the underlying policy, macroeconomic and demographic assumptions (see Chapter 1) lead to gas consumption growth of 1.6% per year between 2016 and 2040, a stark deceleration compared to the 2.3% observed over the past 25 years (Table 8.1). In this scenario, gas expands its share in primary energy supply from 22% in 2016 to 25% in 2040. New gas projects are needed to meet the projected gas demand growth and many of these are either remote or technically challenging or require significant infrastructure construction, putting upward pressure on gas prices. By 2025, gas prices in the United States, Europe and Japan are projected to rise to \$3.7/MBtu, \$8.3/MBtu and \$10.8/MBtu respectively (Table 1.4 in Chapter 1). Over the *Outlook* period, they increase to \$5.6/MBtu in the United States, \$10/MBtu in Europe and \$11.1/MBtu in Japan; the long-term price differentials between markets reflect only the full cost of moving gas between them. Cumulative investment in gas supply (upstream, transmission and distribution infrastructure, liquefaction and regasification facilities) adds up to \$8.6 trillion over the *Outlook* period.

Box 8.1 ▷ What happened to the "Golden Age of Gas"?

8

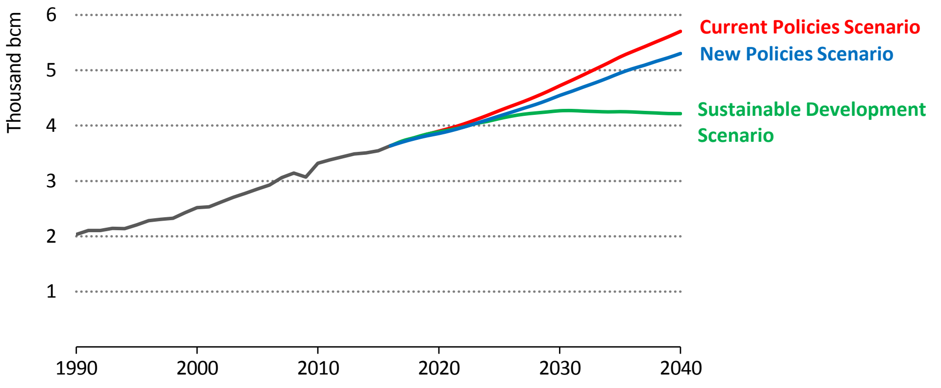
In 2011, the *World Energy Outlook* published a special report asking the question "Are we entering a Golden Age of Gas?", which posited a future in which the role of gas in the energy system expanded more rapidly than in our main scenario, reaching 25% of the global mix by 2035. This was based on a number of positive assumptions about the availability of gas (much of it unconventional) and its price, as well as the addition of policies on the demand side that would promote its use in certain countries, notably China, and in certain sectors, such as transport.

A few years on, where do we stand relative to the putative Golden Age? Natural gas prices in 2016 are very much in line with those anticipated in the "Golden Age" scenario, so in that sense the story of relative abundance has been realised. North American shale gas has been hugely successful; however, contrary to what was assumed in the "Golden Age" scenario, replication of the North American shale gas success story in other shale-rich countries has been very limited (see also Box 9.1 in Chapter 9). In terms of demand, there are substantial variations. Some countries, notably the United States and elsewhere in North America, are already well ahead of the projections in the "Golden Age" scenario; the Middle East and Latin America are also using at least as much gas as anticipated in this "optimistic" scenario. But Europe is at the opposite end of the spectrum, with gas demand having fallen substantially in the last few years. Russia and some other mature gas markets in Eurasia have likewise fallen well short of a Golden Age. Demand in much of developing Asia, notably India, as well as Africa, is also well below the projections in the Golden Age scenario, in countries where gas occupies only a relatively small share of the energy mix.

There is a question mark in the title of the 2011 report "Are we entering a Golden Age of Gas?". The answer, so far, very much depends on where in the world you are.

The Current Policies Scenario, which assumes no new measures beyond those adopted today, sees overall gas demand rise at 1.9% per year to 2040 and end up some 8% higher than in the New Policies Scenario. The share of gas in primary energy supply reaches 24% in 2040, slightly lower than in the New Policies Scenario. The main winner in this scenario is coal: in the absence of many supportive policies that underpin renewables growth in the New Policies Scenario, coal gains ground in the power sector. The share of coal in primary energy supply is 26% in 2040, compared with 22% in the New Policies Scenario. While gas does well, coal does better. The call on new gas supply projects requires a cumulative capital expenditure of $9.8 trillion over the coming 25 years: this implies that the market draws on more costly projects to satisfy demand.

Figure 8.2 ▻ World natural gas demand by scenario



Gas use is projected to increase by 1.6% per year, on average, in the New Policies Scenario

Note: bcm = billion cubic metres.

The Sustainable Development Scenario appears for the first time in this edition of the *WEO.* In this scenario, gas demand grows by 0.6% per year on average. It grows in the years up to 2030, reflecting the contribution that it can make to the environmental goals that this scenario is designed to achieve, notably in replacing coal, but an inflection point is reached around 2030, and gas consumption plateaus as improvements in energy efficiency take hold and as lower carbon fuels expand their share in primary energy supply (Figure 8.2). Nevertheless, gas still accounts for a quarter of primary energy supply in 2040, a higher level than today. Gas prices increase in the Sustainable Development Scenario but less than in the two other scenarios. Similarly, cumulative gas supply investments, at $6.6 trillion, are lower in this scenario.

8.3 A closer look at the New Policies Scenario

8.3.1 Demand

In the New Policies Scenario, global demand for natural gas increases from 3 635 bcm in 2016 to over 5 300 bcm in 2040 (Table 8.1). The additional 1 670 bcm of gas consumption that materialises over the *Outlook* period corresponds to more than twice the current gas use of the United States – the world's largest gas consumer. The average annual demand growth rate of 1.6% between 2016 and 2040 is much faster than that projected for oil or coal, which expand at 0.5% per year and 0.2% per year respectively over this period.

Table 8.1 ▷ Natural gas demand by region in the New Policies Scenario (bcm)

							2016-40	
	2000	2016	2025	2030	2035	2040	Change	CAAGR*
North America	800	961	1 045	1 068	1 109	1 143	182	0.7%
United States	669	779	834	846	867	880	101	0.5%
Central & South America	97	166	183	205	237	271	106	2.1%
Brazil	9	36	38	43	55	64	28	2.4%
Europe	606	590	604	618	633	631	41	0.3%
European Union	487	463	461	467	469	454	- 8	-0.1%
Africa	57	134	177	211	251	306	171	3.5%
South Africa	1	4	5	7	8	10	6	3.8%
Middle East	174	477	568	657	737	795	318	2.2%
Eurasia	471	575	583	593	615	636	61	0.4%
Russia	388	456	452	456	463	470	13	0.1%
Asia Pacific	314	732	998	1 167	1 331	1 472	740	3.0%
China	28	210	397	482	554	610	401	4.6%
India	28	55	97	126	155	183	128	5.2%
Japan	82	123	95	100	106	107	- 16	-0.6%
Southeast Asia	88	170	195	216	244	269	99	1.9%
Bunkers**	0	0	16	26	37	51	51	n.a.
World	**2 518**	**3 635**	**4 174**	**4 545**	**4 950**	**5 304**	**1 669**	**1.6%**

* Compound average annual growth rate. ** LNG used as an international marine fuel.

There is no single answer to the question of why gas fares better than coal and oil in this scenario: instead there are many answers that depend on the availability and price of gas in different countries, and on their end-use patterns and their policies. However, our analysis suggests four common elements that are necessary for gas to thrive over the *Outlook* period (see section 9.3.4):

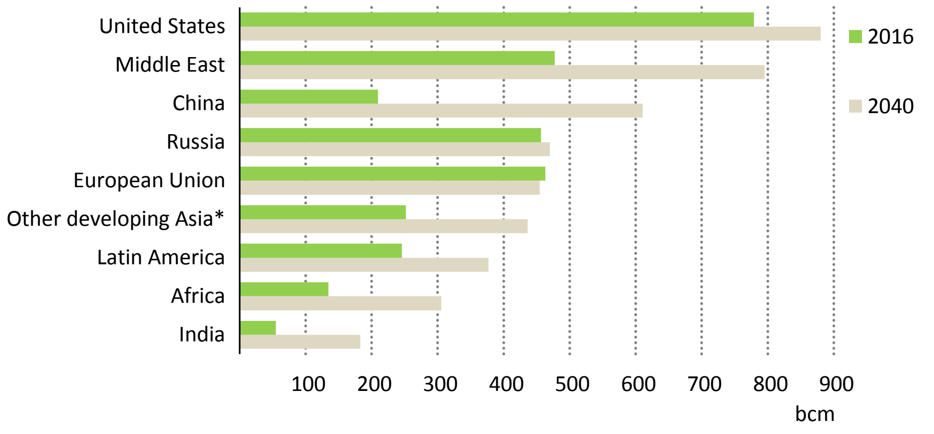
- Gas needs to be reliable and affordable: the shadow of previous disruptions to supply and of periods of price volatility can only be dispelled if costs are kept in check, investments come in a timely and cost-effective manner, and international markets function in a way that brings gas to where it is needed.

- Gas needs to be seen as part of the solution to local and global environmental problems; any doubts about this or about the gas industry's commitment to the highest practicable environmental standards may ultimately reduce its public acceptability (discussed in Chapter 10).
- Gas needs an effective institutional and policy context to underpin investment in essential infrastructure such as import terminals, storage, transmission and distribution networks or refuelling stations for gas-based vehicles or vessels.
- Gas needs its benefits to be recognised and supported through appropriate measures such as carbon dioxide (CO_2) pricing, air pollutant emission standards or electricity market designs that remunerate flexibility.

Regional trends in demand

Although gas demand expands almost everywhere in the coming 25 years – the European Union and Japan are the main exceptions – the growth is clearly concentrated in developing countries (Figure 8.3).

Figure 8.3 ▷ Gas demand in selected regions in the New Policies Scenario

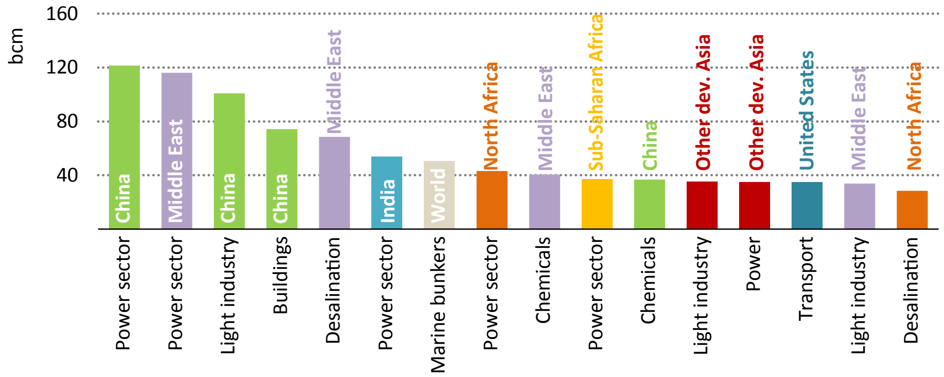


Growth in global gas demand is concentrated in developing countries

*Other developing economies in Asia.

China becomes the second-largest gas consumer in the world by 2040, only surpassed by the United States, and uses more gas than all the countries in the European Union put together (but less than the countries of the Middle East combined). With incremental annual gas use of 400 bcm, China alone accounts for almost a quarter of the additional global demand over the *Outlook* period. China's power sector, with additional demand of 120 bcm, is the single largest growth centre in our projections; its light industry (e.g. textiles, manufacturing, food and beverage) is the third-largest growth centre (Figure 8.4). The light industries are often geographically dispersed around China's large conurbations and feature rather small companies, highlighting the need for infrastructure availability to unlock this growth potential. Bringing gas to the industrial sector is a policy priority for China, not least because of the need to improve urban air quality.

Figure 8.4 ▷ Key natural gas demand growth centres, additional use in the New Policies Scenario, 2016-2040



The Chinese power sector is the single largest growth centre for gas use, but the light industries and gas-based chemical production in various countries are also major hubs

Note: Desalination, normally included in the buildings sector, has been split out for the purpose of this graph.

The **Middle East** is not too far behind China in terms of gas demand growth. The region as a whole consumes an additional 320 bcm in the period to 2040, equivalent to a fifth of global gas growth. Natural gas use is underpinned by additional gas-fired power generation (the region's electricity demand doubles over the *Outlook* period, with much of the growth coming from the buildings sector for cooling and appliances), industrial activity and growing needs for freshwater (gas is used to provide energy for desalination). Moreover, in all sectors, the scope for displacing more costly oil products makes a strong case for higher gas use. The petrochemical industries are major gas consumers in the Middle East: in the long term, several countries in the region place more emphasis on exporting higher value chemical products than on exporting gas. By 2040, the Middle Eastern gas market reaches the same size as the US market today (around 790 bcm).

The United States is a relatively mature and saturated gas market, but still sees gas demand expanding by an additional 100 bcm over the period to 2040. The primary reason is the ample availability of relatively cheap gas that stimulates consumption in the transport sector and industry (see Chapter 9). **South Asia** (e.g. India, Pakistan and Bangladesh) and **Southeast Asia** (e.g. Indonesia, Malaysia, Thailand and Viet nam) also see significant growth in demand for natural gas in the New Policies Scenario, underpinned by economic growth and the associated ramp up in electricity demand and industrial activity. **Africa's** future demand for gas is closely linked to efforts to establish or revive domestic gas markets, notably in Tanzania, Mozambique, Nigeria, Algeria and Egypt.

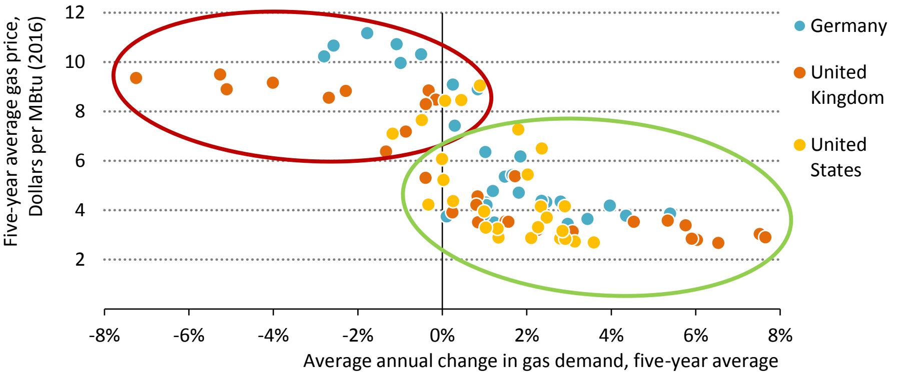
S P O T L I G H T

What's the price for gas demand to grow?

Whether consumers are willing to use gas instead of other alternatives depends on what they need the energy for, alternatives available and costs of the alternatives relative to gas. The considerations for uses such as high-temperature heat in industry, heating a house or generating electricity are very different, but in each case price matters.

Resource-rich nations in the Middle East, North Africa and Eurasia have typically provided gas to their domestic markets at regulated or subsidised prices, often as low as $1 to $2/MBtu. Unsurprisingly, this has led to rampant demand growth in all sectors. However, gas-importing countries such as Japan or Korea have also experienced demand growth, despite wholesale prices of $10-16/MBtu, and Chinese gas consumption grew rapidly at prices around $10/MBtu in recent years. So there is no one answer to the question we pose in this Spotlight.

Figure 8.5 ▷ Change in gas demand versus price in Germany, United Kingdom and United States, 1983-2016



Analysis of historical demand trends in the US, UK and Germany shows that gas use increased at prices below $6/MBtu, but declined at prices above $8/MBtu

It is nevertheless instructive to look at some recent history. Three major gas markets, Germany, United Kingdom and United States, have undergone gas market liberalisation over the past three decades. Statistical analysis of demand growth patterns at different gas prices in these three markets shows that consumption tended to increase when wholesale prices were below $6/MBtu and to decrease when prices were above $8/MBtu (Figure 8.5). These trends hold true for a period spanning more than three decades, with gas prices ranging between $2/MBtu and $12/MBtu and with competing fuel prices also showing large variations. Prices for imported gas in most regions were below $6/MBtu in 2016, but they are projected to increase to above $8/MBtu for much of the latter half of the *Outlook* period.

Every gas market is different and the prices of competing fuels play a key role, so it cannot be concluded that there is no scope for demand growth when gas prices exceed $8/MBtu. This analysis of historical demand growth patterns nonetheless reinforces two key messages of this *Outlook*: first, in some markets – notably where gas is imported over long distances – a purely market-based allocation of gas is unlikely to deliver significant demand growth if it is not complemented by policies that encourage gas use; second, particularly in the light of efforts to liberalise gas markets in China, Japan and other major Asian importing countries, the gas industry needs to work hard on cost control to minimise the risk of losing out to other fuels and technologies.

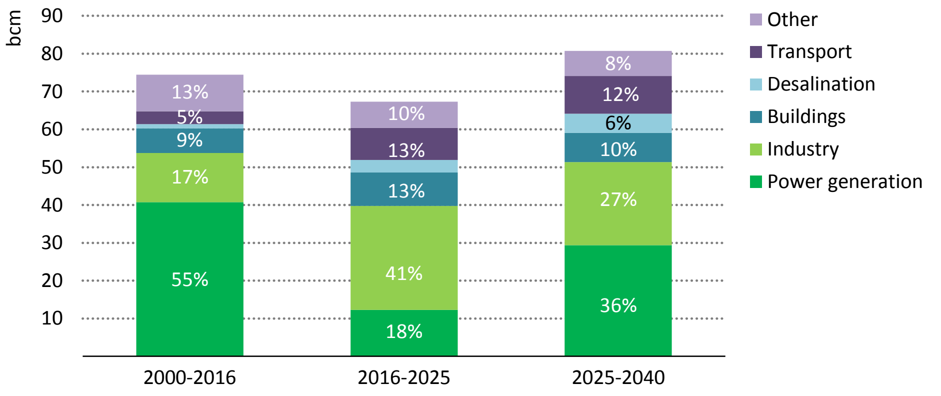
Sectoral trends in demand

With a third of the additional gas demand, industry contributes the largest share of global gas demand growth over the *Outlook* period, ahead of the power sector with 31%, buildings sector (17%) and transport (12%). However, there are important temporal and regional dynamics at play in the coming decades. In the period to 2025, industry is the undisputed growth engine, accounting for over 40% of additional gas use – a marked change compared to the past 15 years when industry contributed less than a fifth to gas demand growth (Figure 8.6). Apart from the rising gas needs of Asian industries, much of this growth materialises in the United States and the Middle East, where cheap gas stimulates growth in the petrochemical industries.

The power sector contributes only 18% to gas demand growth to 2025. This is a symptom of gas getting squeezed between cheaper coal and strong policy-driven renewables deployment in a period in which weaker electricity demand growth in many countries limits the scope for all sources to grow. The United States is a case in point: electricity demand increases by 245 terawatt-hours (TWh) to 2025, but additional output from wind and solar photovoltaic (PV) alone provides an additional 345 TWh to the system. In light of the absence of the Clean Power Plan (the impact of the Clean Power Plan is now no longer considered in the New Policies Scenario), gas faces a battle with coal for space in a market that is contracting. The main increases in gas use in the power sector come in developing Asia, the Middle East and North Africa where economic growth is strong and, at least in the case of the Middle East, cheap gas is more readily available.

After 2025, the power sector resumes its role as the main engine for gas demand growth, accounting for 36% of additional gas demand between 2025 and 2040 (still well below the 55% share of growth achieved between 2000 and 2016). Developing Asia and the Middle East account for the bulk of the additional growth but others, notably the United States and Japan, also exhibit growth in gas demand in the power sector (see Chapter 6). However, gas demand growth in the power sector remains sensitive to how gas prices evolve compared to coal prices and how quickly the costs of variable renewables come down. In the industry sector post-2025, gas demand growth is concentrated in light industries, as the rise in gas prices around the world constrains the growth of production of gas-based chemicals. By 2040, combined gas demand from light industries in China, United States, Middle East and European Union accounts for a quarter of global industrial gas consumption. Industrial gas use in developing countries in South Asia, Southeast Asia and Africa also grows strongly over the *Outlook* period, on the assumption that transmission and distribution infrastructure will be available.

Figure 8.6 ▷ Annualised growth of global natural gas demand by sector in the New Policies Scenario



Industry propels gas demand strongly upwards in the period to 2025, but thereafter, momentum shifts to the power sector

Notes: Desalination, normally included in the buildings sector, has been split out for the purpose of this graph. Industry includes gas used as petrochemical feedstocks and for the production of liquid fuels as well as energy consumption in coke ovens and blast furnaces in all focus chapters on natural gas.

Gas demand in the buildings and transport sectors grows by 36% and over 170% respectively between 2016 and 2040. The majority of gas used in buildings today is for space heating: however, demand for space heating in most developing countries is limited (with the important exception of China) and this constrains the potential for growth in the sector, even though other end-uses such as cooking and water heating increase in importance. Desalination plants, mostly in the Middle East and North Africa, are an important element of gas demand growth (almost 100 bcm to 2040). Road transport accounts for the bulk of additional gas use in the transport sector, with growth concentrated in three countries: more than 70% of the additional gas demand in road transport comes from China and the United States (each seeing an increase of around 35 bcm to 2040) and India (an additional 22 bcm to 2040). Demand for natural gas as a shipping fuel rises, mostly due to the International Maritime Organization's regulations on sulfur emissions from vessels and energy efficiency targets; as such marine bunkering adds a further 60 bcm to demand over the *Outlook* period.

In summary, although gas does better than oil and coal, gas demand growth of 1.6% per year between 2016 and 2040 is significantly slower than the annual demand growth of 2.3% over the past 25 years. This is the result of two overarching trends: first, global total primary energy demand growth slows to 1% per year over the period, down from an annual growth rate of 1.7% between 1990 and 2016. Second, gas faces an increasingly competitive environment: gas use in power generation is curtailed in many countries by the growth of renewables and in some by less expensive coal. In the buildings sector and industry, it faces competition with electricity and constraints arising from increased energy efficiency, and the effects of these outweigh gains from new demand in areas such as shipping and road transport. Overall, the prospects for natural gas are good, but our projections suggest that the industry cannot expect a return to previous long-term growth rates.

8.3.2 Supply

Resources and reserves

The remaining resources of natural gas are sufficient to comfortably meet the projections of global demand growth to 2040 and well beyond, in all three scenarios of this *Outlook*. Proven reserves stood at some 215 trillion cubic metres (tcm) at the end of 2016, equal to around 60 years of production at current output rates (Table 8.2). Yet, remaining technically recoverable resources provide a better indicator for how much gas can be produced in the long term, and our modelling of gas production trends is thus based on resources rather than reserves. Global resources of natural gas are estimated at nearly 800 tcm, around 45% of which are unconventional gas (tight gas, shale gas and coalbed methane), deposits of which are geographically more widespread than conventional gas resources.

Table 8.2 ▷ Remaining technically recoverable natural gas resources by type and region, end-2016 (tcm)

	Conventional	Unconventional				Total	
		Tight gas	Shale gas	Coalbed methane	Sub-total	Resources	Proven reserves
North America	51	11	61	7	79	130	12
Central & South America	28	15	41	-	56	84	8
Europe	19	5	18	5	28	47	5
Africa	51	10	40	0	50	101	17
Middle East	103	9	11	-	20	123	80
Eurasia	134	10	10	17	38	172	74
Asia Pacific	45	21	53	21	94	139	20
World	**432**	**82**	**233**	**50**	**365**	**796**	**216**

Sources: BGR (2016); BP (2017); Cedigaz (2017); OGJ (2016); US DOE/EIA/ARI (2013); US DOE/EIA (2017); USGS (2012a, 2012b); IEA databases and analysis.

Production

Production of natural gas expands globally by 1 685 bcm over the next 25 years, reaching over 5 300 bcm in 2040 (Table 8.3). The United States, Russia and Iran are the three largest gas producers today, a ranking that remains unchanged over the *Outlook* period although China comes close to that of Iran by 2040.

Table 8.3 ▷ Natural gas production by region in the New Policies Scenario (bcm)

	2000	2016	2025	2030	2035	2040	2016-40	
							Change	CAAGR*
North America	763	960	1 166	1 212	1 282	1 338	379	1.4%
Canada	182	174	159	165	190	222	49	1.0%
Mexico	37	37	35	38	48	58	21	1.9%
United States	544	749	971	1 009	1 043	1 058	309	1.4%
Central & South America	102	175	178	207	242	279	104	2.0%
Argentina	41	42	53	70	90	104	62	3.9%
Brazil	7	24	28	43	60	77	53	5.0%
Europe	337	285	244	238	236	236	- 49	-0.8%
European Union	264	134	91	85	80	76	- 58	-2.3%
Norway	53	121	105	101	99	100	- 22	-0.8%
Africa	124	205	273	330	392	460	254	3.4%
Algeria	82	92	97	102	107	113	21	0.8%
Mozambique	0	5	13	32	49	64	59	11.6%
Nigeria	12	41	46	45	56	70	29	2.2%
Middle East	198	585	703	832	931	1 003	418	2.3%
Iran	59	190	243	301	332	338	149	2.4%
Qatar	25	165	182	214	240	256	91	1.8%
Saudi Arabia	38	90	107	120	131	142	52	1.9%
Eurasia	691	842	935	978	1 035	1 095	252	1.1%
Azerbaijan	6	19	37	44	51	55	36	4.6%
Russia	573	644	718	730	752	788	144	0.8%
Turkmenistan	47	80	86	102	124	141	61	2.4%
Asia Pacific	290	568	675	749	832	894	326	1.9%
Australia	33	88	149	162	188	195	107	3.4%
China	27	137	222	261	298	336	199	3.8%
India	28	31	42	59	72	84	53	4.3%
Indonesia	70	77	70	73	80	90	13	0.6%
Rest of Southeast Asia	89	146	128	131	131	127	- 19	-0.6%
World	**2 506**	**3 621**	**4 174**	**4 545**	**4 950**	**5 304**	**1 683**	**1.6%**
Unconventional	196	780	1 180	1 320	1 486	1 654	874	3.2%

* Compound average annual growth rate.

Unconventional sources account for more than half of the incremental gas output. Unconventional gas is not a homogenous group: shale gas production – especially in North America – is the clear frontrunner, adding 725 bcm to the global gas balance; next comes coalbed methane, which contributes over 60 bcm (see Focus), followed by tight gas, which contributes over 35 bcm. The United States is the undisputed growth engine for global shale gas production: output reached over 445 bcm in 2016, and we project a rise to 800 bcm by 2040. Although the surge in US shale gas production delays the shale gas boom in Canada, good quality resources and positive spill-over effects from the United States underpin a marked ramp up in Canadian shale output in the second-half of the *Outlook* period, bringing production to almost 155 bcm in 2040. China – which is estimated to hold the world's largest resources of shale gas – increases production of shale gas to almost 100 bcm in 2040, from an output level of 8 bcm in 2016. The key uncertainty for Chinese shale gas, as for all such resources outside North America, is the quality of the resource and the cost at which it can be produced (see Chapter 14). Our assessment of Argentina's shale gas outlook is relatively upbeat: the early signs from drilling activity thus far suggest a potentially prolific resource (especially in the Vaca Muerta play). Argentina has a well-established gas market and infrastructure, and an increasingly favourable regulatory environment. Against this backdrop, we project Argentinian shale gas output to rise to nearly 50 bcm in 2040; if investment is forthcoming, the resource base could support considerably higher output.

Conventional gas currently accounts for nearly 80% of the world's gas production, but this share falls back to under 70% by 2040. Unconventional gas production is well-known for high initial decline rates, but conventional gas fields also face post-peak average declines of over 7%; countering this continual drain on supply is a major challenge for the gas industry. Russia is currently the largest producer of conventional gas – the bulk of which comes from its West Siberian gas fields – and remains so over the next 25 years. Russia's total output tops 785 bcm in 2040, which is more than 20% higher than today's level. Other major conventional gas producers are Iran and Qatar, both of which exclusively produce conventional gas and see their output rising by almost 80% and 55% respectively.

Associated gas is gas produced as a by-product of oil production. Today it accounts for around 15% of the world's gas output. This share has been falling over recent decades: in 1980, associated gas accounted for a quarter of the world's gas production. We see the current 15% share staying flat in the first-half of the projection period as gas-rich tight oil production in the United States expands, before dropping off in the second-half of the projection period to around 10% in 2040.

Focus: What are the prospects for coalbed methane?

Coalbed methane, referred to in Australia as coal seam gas, is produced from coal seams, typically at depths of 800 to 1 200 metres. Relatively shallow coal seams are targeted: deep seams tend not to be economical to produce. There is a contrast here with shale gas, which is often economical at much greater depths. The primary extraction technique requires dewatering the coal seams, i.e. pumping out the formation water that effectively traps the gas in the coal seam. This typically requires a large number of vertical wells. As water is removed, gas begins to flow relatively easily. While the method of extraction may be unconventional, the product, methane, is the same as any other type of natural gas.

In common with other methods of unconventional gas production, gas recovery from each individual well is low, and depletion rates are relatively rapid. As a result, more production wells must be drilled to expand and maintain output than would be the case for typical conventional fields. While stimulation techniques of the type used for shale can be employed, in practice relatively few wells are hydraulically fractured. For example, in Australia, early exploitation of coalbed methane saw only about 6% of wells hydraulically fractured, although over time this is expected to rise to around one-third. The large volumes of water used in extraction must be treated, most commonly by reverse osmosis: while 90% of the water so treated can be reused (for example for irrigation or livestock) a concentrated saline solution remains, which initially is retained in ponds and then either crystallised and secured in specially-lined land-fills or disposed of in deep saline aquifers. This poses potential environmental risks.

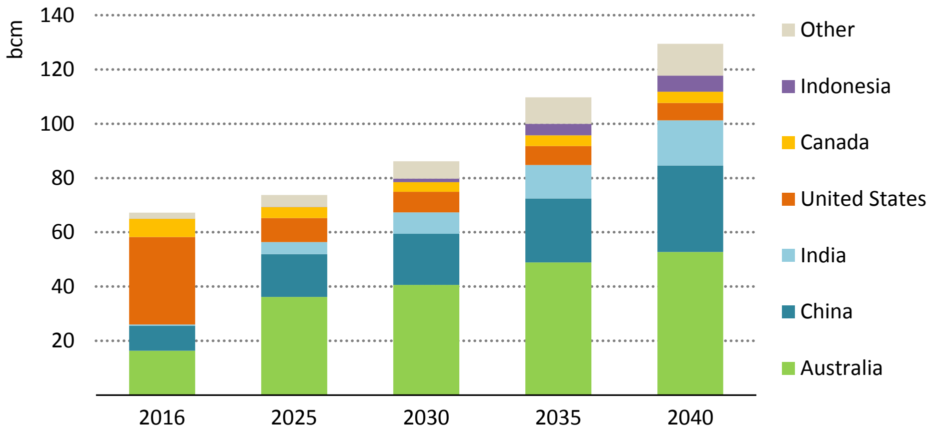
Coalbed methane resources are relatively widespread globally, but so far, production has only picked up in the United States, Canada, Australia and China, and remains at a relatively modest level in comparison to shale. Global production nearly doubled between 2000 and 2016 to 70 bcm: over the same period, shale gas output increased more than twenty-fold to 460 bcm. In our projections, global coalbed methane production increases to around 130 bcm by 2040. In the United States and Canada, higher cost coalbed methane struggles to compete with shale gas, for which costs have been dropping dramatically. In Australia, output has risen rapidly in the last ten years, mainly to support a burgeoning LNG export industry. Production is projected to increase to 35 bcm by the early 2020s, at which point Australia becomes the largest global producer of coalbed methane, and then to rise further to 55 bcm by 2040 (Figure 8.7). China has ambitious plans to increase unconventional gas production, including coalbed methane (and coal mine gas, which is gas captured and marketed from coal mining operations). Coalbed methane accounts for around 30 bcm of the 225 bcm of unconventional gas production in China in 2040. A number of developing countries, chief among them are Indonesia and India, also increase their production of coalbed methane over the period to 2040.

Although coalbed methane uses a different suite of production technologies from shale gas, it has aroused similar environmental and social concerns in a number of countries, focusing on possible water contamination, land access and fugitive emissions.[1] In Australia, for example, large-scale coalbed methane production is found only in the state of Queensland. Australia, in common with several other federal jurisdictions, regulates unconventional

1. These topics were the subject of discussion at the IEA's 5th Unconventional Gas Forum, held in Brisbane in February 2017.

gas production at the state/provincial level, and other states have effectively prohibited production via moratoria on hydraulic fracturing and/or gas development in general (Victoria, Tasmania and, most recently, Western Australia) or put it on hold pending various inquiries into adequate safeguards (New South Wales). In Queensland, a number of important regulatory approaches and institutions have been developed to address these concerns: a cumulative approach to assessing environmental and water impacts has been put in place, a statutory body for ground water impact assessments has been set up, and a specialised forum, the Gas Fields Commission, has been established to promote dialogue among the various stakeholders.

Figure 8.7 ▷ Coalbed methane production in selected countries in the New Policies Scenario



Australia leads the long-term growth in coalbed methane extraction

Costs of production for coalbed methane have proven difficult to bring down. Moreover, coalbed methane is dry, i.e. lacking the hydrocarbon liquids that are an important additional revenue source and a key factor for the rapid growth of shale gas in the United States. Even in Australia, with two decades of production experience and thousands of wells drilled, wellhead prices have stayed in the region of $3.5-4/MBtu (around 5 Australian dollars per gigajoule). Innovation is improving productivity, for example through drilling more directional wells from a single pad (which also reduces the surface footprint of projects that may have thousands of production wells), but coalbed methane has yet to demonstrate the extraordinary cost reductions seen in shale gas. At the three LNG projects in Australia that are fed by coalbed methane, upstream costs look likely on the basis of current LNG export prices to translate into low profitability on the more than $60 billion invested. Relatively high costs of production temper our overall projections for coalbed methane, compared with other sources of unconventional gas, notably shale gas.

8.3.3 *Regional demand and supply insights*[2]

Russia

Russia appears well placed to benefit from the world's growing gas needs – it has a huge resource base and relatively low production costs – but the remoteness of its main gas fields means that it is difficult to get the gas to the growth centres of the global gas market. Russia's gas export industry was built on bilateral trade relationships with European countries, but inflated expectations of gas demand growth in Europe and also in Russia itself and in other Eurasian countries has left Russia with more than 150 bcm of spare gas production capacity following the decision to invest in the Yamal peninsula in the mid-2000s. Russia also has ample pipeline capacity into Europe via four main arteries (via Ukraine, via Belarus, directly to Germany [Nordstream] and directly to Turkey [Bluestream]).

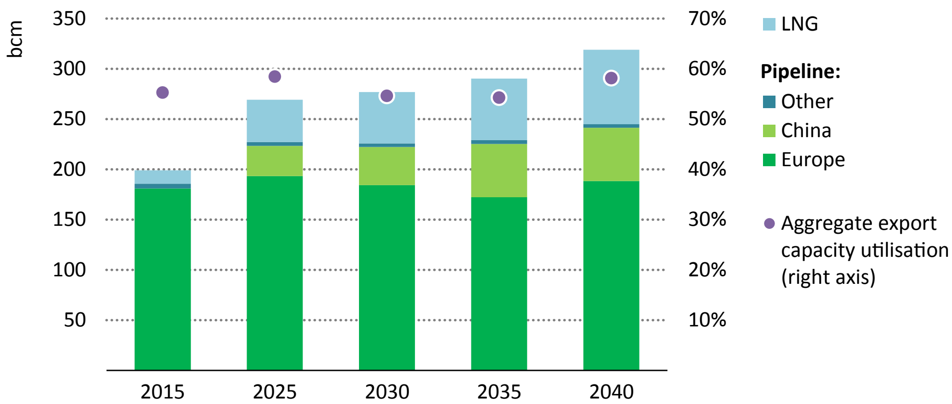
Russia's strategic focus on the European market, and reliance on pipelines for export, means that Russia has very few other export outlets for its gas, and it currently depends on the vagaries of European gas demand for some 90% of its gas exports (and hence gas export revenues). No relief can be expected from the Russian domestic gas market: our projections suggest that Russian gas demand plateaus in the coming decades, reaching a figure of 470 bcm in 2040, or 3% higher than the level reached in 2016. Gas already accounts for more than half of Russian primary energy demand and even modest energy efficiency gains in the power, industry and buildings sectors will be sufficient to keep future growth in check.

The primary goal for the Russian gas industry is thus to diversify its export options. A major step in this direction is the "Power of Siberia" pipeline to China, which is currently under construction. It is expected to come on stream soon after 2020, with the ramp up to full capacity (38 bcm) accomplished around the middle of the decade. In the New Policies Scenario, we project a further expansion of eastward pipeline capacity in the latter part of the *Outlook* period (operational from the early 2030s), which could come either from an expansion of the eastern route or from the "Altai" pipeline, a proposed link to Western China. An additional set of uncertainties for some prospective projects stems from an extension of US sanctions in August 2017 to cover Russian energy export pipelines.[3] Diversification based on LNG is well underway, with one facility operational and another one slated to gradually enter service in the coming years. But potential sites for liquefaction terminals are remote and the conditions for construction and operation of the facilities can be harsh. As a result, our projections suggest a gradual expansion of LNG capacity, despite ample availability of gas.

2. Insights on the North American gas market are presented in Chapter 9 and the Chinese gas market is discussed in Chapter 14.

3. There are several existing and prospective gas transmission corridors into Europe. *WEO* modelling of future trade flows between Russia and Europe is consistent with several of these options.

Figure 8.8 ▷ Russian gas exports by destination and aggregate utilisation of export capacity in the New Policies Scenario



Under-utilised capacity gives Russia near-term flexibility in supplies to Europe, while new pipelines to the east and LNG provide longer term diversity of markets and revenues

8

In the New Policies Scenario, Russian exports increase by two-thirds, reaching some 315 bcm in 2040 (Figure 8.8). Although it takes time, our projections see Russia successfully unlocking new gas markets, bringing dependence on the European market down to around 60% of its exports in 2040. New export infrastructure achieves higher utilisation rates than the existing connections to Europe and this brings aggregate utilisation of export capacity slightly up to almost 60% in 2040, from 55% in 2015. Nevertheless, there remains significant slack in the system, implying that Russia could increase its market share in Europe if it were willing to accept a lower price (see Spotlight in Chapter 9), although it should be noted that many European countries see diversity of gas supplies as important. It also implies that, if global gas markets were to tighten, Russia could quickly ramp up pipeline gas exports to Europe and displace some LNG there that could then be re-routed to alleviate shortages elsewhere.

Middle East

Underpinned by ample availability of gas at low regulated prices, gas demand in the Middle East expanded at a remarkable 6.8% per year over the last 25 years. However, in recent years production has had difficulties in keeping up with demand growth. Despite having access to some of the lowest cost gas in the world, the incentives for gas producers in the countries of the Middle East are, in many cases, insufficient to bring on new projects. Gas prices often still reflect the remuneration that was adequate when gas demand growth could be covered primarily with associated gas (which as a by-product of oil has very low production costs). To meet future demand growth, however, production increasingly has to shift to non-associated gas fields where project economics rely on gas rather than oil prices. Some of the non-associated gas fields, such as the recently developed Shah field in the United Arab Emirates, are moreover high in sulfur and thus more complicated and expensive to produce. A key challenge for the governments of Middle Eastern countries is thus to strike a careful balance between the commercial costs faced by producers on the one hand and the level of domestic prices on the other: domestic price rises would help to close the gap between them, but would be unpopular.

Our projections indicate that the growth of gas demand slows to 2.2% per year over the next 25 years, reaching almost 795 bcm in 2040, reflecting increasing prices (i.e. a gradual phase-out of fossil-fuel subsidies), efficiency gains and saturation effects. Nevertheless, with an additional 320 bcm of gas use, demand for gas grows by more in the region as a whole than anywhere else except China over the *Outlook* period. Power generation is the frontrunner, accounting for more than one-third of the incremental gas consumption, followed by industry which contributes nearly 30%. Displacing oil use in these sectors is a major opportunity for gas: in 2016, nearly a third of the region's power needs were generated from oil, but that share drops to around 10% in 2040. Seawater desalination is another major growth area for gas, both in large plants that combine freshwater production with electricity generation and in smaller units in the buildings sector.

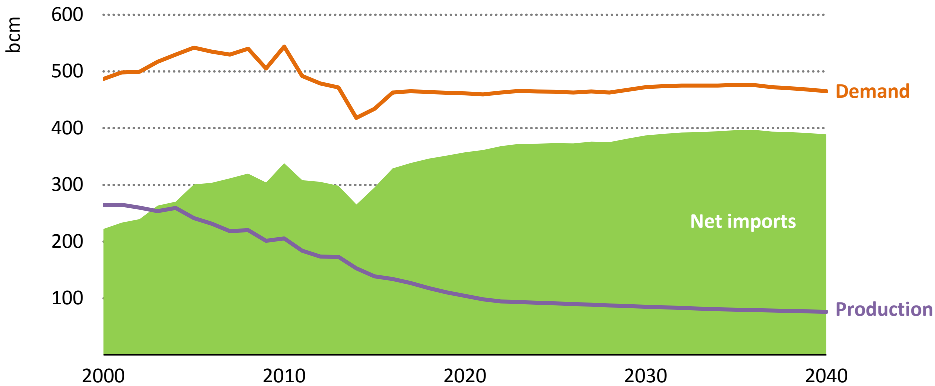
In our projections, Iran leads gas output growth in the Middle East, adding 150 bcm to the region's gas supply in the period to 2040. Although many uncertainties remain, the lifting of the main international sanctions and the recent presidential elections has raised the likelihood of foreign investment in continued development of the super-giant South Pars field (the northern part of the world's largest gas field with the other part being Qatar's North Field), with a number of Asian and European companies showing interest in participation. Satisfying domestic needs is the priority for Iranian gas producers, but we also anticipate some export growth via links to Iraq and Oman, as well as further deliveries to Turkey and, much later on the projection period, the start of a pipeline connection with Pakistan.

In early 2017, Qatar decided to lift its self-imposed development moratorium on the North Field. Such a decision had been anticipated in previous editions of the *WEO*, so does not lead to any dramatic change to our projections in this *Outlook*. Nonetheless, the lifting of the moratorium is a significant declaration of intent at a time of ample supply, reflecting a determination – and an ability, given Qatar's low-cost structure – to maintain a leadership role in global LNG. Our projections show Qatar's production increasing by 55% and reaching some 255 bcm in 2040. Most of the increase in output is geared towards the international market and Qatar remains the primary source of exports from the region.

European Union

Gas demand in European Union (EU) countries is estimated to have jumped by 7% to over 460 bcm in 2016. Greater gas use for power generation was the main driver of this trend, and the power sector remains central to the long-term prospects of gas in the European Union. The EU's target to cut greenhouse-gas emissions by 40% (compared with 1990 levels) in 2030 forces many coal plants into retirement and underpins a rise of CO_2 prices in the European Union Emissions Trading System to $35 per tonne of CO_2 in 2030 and nearly $50 per tonne in 2040. This creates space for gas in the power sector, even with renewables increasing strongly over the *Outlook* period. Another stimulus for greater use of gas in the EU power system comes from a more downbeat outlook for nuclear power. This edition of the *WEO* sees output from the nuclear power plants in EU countries dropping by 30% in the coming 25 years and installed capacity falling from 127 gigawatts (GW) in 2016 to around 85 GW in 2040 – nearly 20 GW less than in the *WEO-2016*. As a result, gas use in the power sector expands slightly in the period to 2040, and over 110 GW of new gas-fired power plants are built to replace retirements and to provide flexibility for an increasing share of variable renewables. Natural gas consumption in the European Union stays around current levels for most of the projection period before dropping slightly to 450 bcm in 2040 (Figure 8.9).

Figure 8.9 ▻ Natural gas balance of the European Union in the New Policies Scenario



Even with a flat demand outlook, the European Union's gas imports increase to 2040 as domestic output continues to decline

Domestic EU production drops sharply over the *Outlook* period to around 65 bcm in 2040, 50% below current output levels. The European market has proved its ability to adapt to rapidly changing production prospects in the past few years. When output from the super-giant Dutch Groningen field dropped by over 40% between 2013 and 2016 (production was capped due to concerns about increased seismic activity from gas extraction), the loss of some 30 bcm in the European gas balance was smoothly compensated for, triggering no major price reaction. It clearly helped that this happened at a time when plenty of gas was available on the international market. The European Union nevertheless is well placed to substitute falling domestic output with imports; it has a well-functioning and efficient internal gas market, many under-utilised regasification terminals, and a wide portfolio of pipeline import routes. The projected retirement of almost 80% of the region's coal-fired capacity however will mean the loss of a source of flexibility to respond to demand fluctuations, so gas security is set to remain an important topic on policy-makers' agendas.

Our projections see EU gas imports increase by some 60 bcm, reaching around 390 bcm in 2040. Russia remains the largest supplier of gas to the European Union, maintaining its market share of around 40%. Production in Norway – the second-largest source of imports – remains at high levels over the next few years, helped by expansions on the super-giant Troll field in the North Sea and by the coming online of the new Aasta Hansteen development in 2018. However, Norway faces the prospect of declining export availability over the longer term: after 2020 production is expected gradually to decline from just above 120 bcm to 100 bcm towards the end of the *Outlook* period. Gas production in the North Sea is mature and remaining resources in the Norwegian Continental Shelf are not sufficient to sustain current production levels and new discoveries are not expected to be sufficient to fill the gap. Further north, the Barents Sea holds more exploration promise and could potentially impact the longer term production outlook. Expanding production in the Barents Sea beyond the currently operational Snøhvit project would however require new gas discoveries and subsequent significant investments in new production facilities and infrastructure.

As Norwegian shipments drop, a range of other suppliers expands into the European market. Chief among them are US LNG suppliers, who reach a market share of just over 10% in 2025 and then keep this share in the longer term. Together with LNG from other sources, for instance from Qatar and East Africa, this means that the European Union's reliance on pipeline gas imports drops from over 85% in 2016 to two-thirds in 2040. Middle Eastern countries and suppliers from the Caspian (especially Azerbaijan) make inroads into the European market, so the diversity of pipeline gas suppliers also increases. Shale gas in Europe does not make a material difference to the EU's gas balance: although resources in some countries are promising, there are geological challenges in many places, together with political and public concerns.

Caspian region

Turkmenistan has large resources of relatively low-cost gas but faces the challenge of getting its gas from the centre of Eurasia to potential markets. Its geographic location means that it cannot opt for LNG exports (a constraint that other exporters in the region like Azerbaijan also face). Satisfying rising gas needs in the European Union, China, Pakistan or India therefore requires long-distance cross-border pipelines that transit at least one other country. Two close neighbours, Russia and Iran, are moreover themselves large gas producers, limiting their potential as export markets and their interest in being transit countries (for instance, Russia, a traditional off-taker of Turkmen gas, has reduced its purchases over the past ten years and ceased to import Turkmen gas altogether in 2016). This puts Turkmenistan at a significant disadvantage to other exporters.

The rise in global LNG trade is likely to make it harder for capital intensive, complex and politically challenging pipeline projects out of the Caspian region to secure political and financial backing. As a result, we have re-assessed the timelines of a number of pipeline projects. The fourth pipeline link between Turkmenistan and China (Line D), on which work has been suspended, is delayed considerably in our projections and enters into service only in the mid-2020s. Even more significantly, and contrary to assumptions in previous editions of the *WEO*, we no longer assume that any pipeline connection between Turkmenistan and South Asia (TAPI) is feasible by the end of the projection period. Security is one major concern for TAPI, given that the pipeline route runs through areas of Afghanistan under Taliban control. Financing and project management is a second: for the moment, Turkmengaz (the state-owned gas producer) is the sole consortium leader, but there are doubts about whether it has the capacity to spearhead a complex international project and there is, so far, no partner involved in the project from among the leading international global oil and gas companies. As well, at least for the next few years, there are questions about the commercial rationale for the project: although gas from the super-giant Galkynysh field, delivered via large-scale pipeline, should be competitive in the long term, potential customers like India and Pakistan have access to LNG at price levels that, at least for the time being, are difficult for the proposed pipeline to match.

Azerbaijan manages to place growing volumes of gas on the European market via a number of pipelines that are in an advanced stage of realisation. Nevertheless, exports from the country remain, in the long term, markedly below the level that its resource and cost base would suggest is possible.

Overall, despite the difficulties they face in getting gas to foreign markets, countries in the Caspian region increase gas production from nearly 200 bcm in 2016 to over 305 bcm in 2040. Around 55% of the region's incremental output comes from Turkmenistan, which increases output by over three-quarters to over 140 bcm, while Azerbaijan contributes a third to production growth, reaching output of 55 bcm (a tripling compared to the level reached in 2016). Kazakhstan also increases its production over the coming 25 years while that of Uzbekistan declines. Production growth in the region satisfies a 40% increase in gas demand but, even if the region does not realise its full export potential, the bulk of growth feeds pipeline exports, most importantly to China.

Australia

Australia is well on the way to becoming a major LNG exporter, with over 60 bcm of liquefaction capacity brought online in the past five years and another 30 bcm scheduled to become operational before 2020. The Australian investment wave has been plagued by major cost overruns and by some delays in starting up facilities, e.g. at the Gorgon offshore project. A rise in domestic prices also sparked a debate over the adequacy of domestic gas supply that culminated in the introduction in 2017 of a temporary gas security mechanism that would allow the government, under certain circumstances, to curtail export in favour of domestic deliveries. In our *Outlook*, projects that are currently under construction gradually ramp up, and Australian output reaches around 150 bcm in 2025 (up from just under 90 bcm in 2016) before increasing to 195 bcm in 2040. Some new projects come to fruition over the *Outlook* period, but these are mostly smaller incremental projects and there is no second investment wave comparable to the boom of the last ten years.

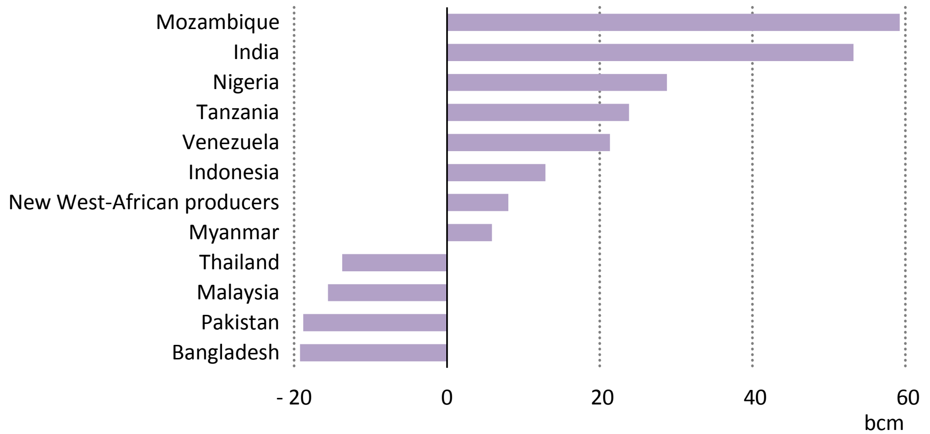
India

Gas remains a relatively minor component of the Indian energy mix, and concerns about affordability and reliability have plagued its development in many parts of the country; Gujarat, with well-developed infrastructure and relatively high gas penetration, is an exception. However, there is major growth potential in the power sector and in industry, where fertiliser manufacturing is the biggest energy user. In our projections, the use of gas for electricity generation is the largest single source of growth for gas, with over 40% of the total increase: gas provides a valuable source of flexibility to a market in which solar plays a big role but which has an evening peak in electricity demand. There is also now a more concerted push to get gas into the Indian energy system because of rising concerns about air quality in India's major cities. India already has the fifth-largest natural gas fuelled vehicle fleet in the world. This reflects the outcome of policy and programmes to encourage compressed natural gas (CNG)-based taxis, buses and two/three-wheelers in cities such as Mumbai and Delhi, and to provide adequate refuelling infrastructure to support the roll out. This provides a solid basis for a nine-fold gas demand expansion in the transport sector to over 25 bcm in 2040.

On the supply side, low domestic gas prices have been a major impediment to resource development. Recent pricing reforms, allied with the new Hydrocarbon Exploration and Licensing Policy, should help to address this. The recent decision by BP and Reliance to move ahead with deepwater gas investment represents an important vote of confidence in India's gas outlook. However, our analysis of India's gas supply costs suggests that, for the moment, most commercial new projects are marginal in the current gas price environment, and this means that most growth on the production side takes place only after 2025. Overall, with upstream reform assumed to advance, the New Policies Scenario sees domestic gas output grow from 31 bcm today to some 85 bcm in 2040 (Figure 8.10).

New infrastructure investment will be essential if gas markets and consumption are to expand in India. The prospects for gas use in the power sector are closely connected to broader electricity reforms to relieve the financial stress on the local distribution companies, which can lead them to refrain from dispatching higher cost gas-fired capacity when it is needed. Downstream infrastructure and import facilities need to grow in lockstep, which requires integrated infrastructure planning, and regulation at national level on network access. India's large coastal metropolitan areas and industrial hubs, with actual or potential access to LNG markets, provide a natural focus for gas market and infrastructure development. The New Policies Scenario assumes that steps are taken on planning and regulation, and that LNG imports rise from just under 25 bcm in 2016 to nearly 100 bcm in 2040.

Figure 8.10 ▷ Change in natural gas production in selected developing countries in the New Policies Scenario, 2016-2040



Emerging gas producers see their output increase strongly while some more established gas producers, especially in Asia, need to offset falling production with imports

East Africa

Major offshore discoveries in Mozambique and Tanzania have created high expectations for local gas market development and for a significant role for the two countries in the international LNG business. Although the resources discovered are sizeable (the discoveries in Mozambique's Rovuma basin alone are estimated at 3.5 tcm) and the upstream costs relatively low, getting the gas from the fields to consumers is not straightforward. Gas use in Mozambique is marginal and the main consumption hubs are almost 2 000 kilometres (km) to the south, around the capital Maputo. Tanzania is in a slightly more favourable position in this respect; the distance to Dar-es-Salaam is much shorter and an 8 bcm pipeline is already in place. However, even under optimistic assumptions, the domestic markets and those of neighbouring countries (notably South Africa) remain, for the foreseeable future, too small to absorb more than a fraction of the gas production from the offshore fields. Exports to growing gas markets in Asia (especially India) and Europe are thus at the core of a strategy to develop East Africa's gas resources. However, the area in which the LNG facilities are needed is remote, with implications for the complexity and cost of the construction phase. The first step towards tapping the huge resources is being made with a floating LNG vessel for the Coral development in Mozambique (Box 8.2), with onshore liquefaction trains anticipated later in the 2020s.

We project gas production in Mozambique to increase gradually to 13 bcm in 2025 before taking off in the second-half of the *Outlook* period and approaching 65 bcm by 2040, and production in Tanzania to reach 25 bcm by 2040. Gas export via onshore liquefaction terminals could accompany domestic pipeline development (pipelines that could be expanded into South Africa in the case of Mozambique or into Kenya in the case of Tanzania), but the creation of local gas demand hubs that are served via floating storage and regasification facilities (FSRU) requires less capital expenditure and may prove a more flexible way of making gas available. Although energy needs are growing quickly, the region has ample coal resources and good renewable energy potential within easy reach, so whether gas indeed makes inroads to the local energy mix hinges critically on the legal and regulatory regime and the availability of anchor consumers in power generation and industry that can underpin new infrastructure.

Box 8.2 ▷ How floating technologies can enable gas market development

Floating liquefied natural gas (FLNG) is a nascent technology that allows offshore gas fields to be tapped by a vessel containing a liquefaction unit that can produce LNG and transfer it directly onto LNG carriers. There is currently only one such vessel operational (in Malaysia), but various others are in the investment pipeline. The Prelude FLNG vessel arrived at its prospective production location off Western Australia in mid-2017. A large vessel (4.7 bcm a year) has been chosen to kick-start development of Mozambique's remote, but prolific, Coral field, while a smaller FLNG vessel (just under 2 bcm per year) is planned to produce LNG for some eight years from the tiny Kribi field off Cameroon's coast (after which it can be deployed elsewhere).

FLNG is variable in size (0.7 bcm to 5 bcm), but typically smaller than onshore liquefaction plants which require a certain size (often more than 5 bcm) to benefit from economies of scale. The vessel cost and construction time is likely to vary significantly depending on whether it is a new-build or a conversion and on its complexity. Costs for the initial projects have been relatively high, but are expected to come down: FLNG is a promising technology to unlock gas deposits that are too remote or not large enough to justify the construction of an onshore plant and subsea pipelines.

At the other end of the LNG shipping chain are Floating Storage and Regasification Units (FSRUs), which are vessels that can be moored at sea or docked in a port to regasify LNG and feed it into a transmission or distribution network (or deliver it directly to an end-user). FSRUs are an affordable, fast and flexible way to get access to natural gas supplies. Developing countries that lack existing infrastructure need to develop their gas markets gradually. One way of doing so is to establish an anchor consumer, such as a power plant, in an industrial hub and then gradually expand infrastructure from there. LNG-to-power projects are being pursued in Ghana, Namibia, Senegal and South Africa to create a domestic gas market, and FSRUs fit well with such projects because they are scalable, fast to deploy and require substantially less (sunk) capital than an onshore terminal or a large cross-border import pipeline project. The cost of a new FSRU including the necessary auxiliary facilities can be 40-50% lower than that of an onshore facility while LNG tanker conversions are even less expensive.

Currently there are over 20 FSRU terminals in operation worldwide and several more are under construction. Many of the terminals are in countries that have existing gas markets (e.g. Pakistan, Argentina, Brazil or Egypt) in order to replace or complement existing supplies, or to balance seasonal demand fluctuations. The relative ease of moving floating facilities (both FSRU and FLNG) means they can easily be redeployed, which reduces risk for investors and lowers the hurdles for access to finance that are important considerations for developing countries. Terminals have the potential to help developing countries to shift from more costly oil products or more polluting coal to gas when this would otherwise not be possible or economically viable.

Other developing countries

Infrastructure availability and gas market reform are common challenges in various gas-rich countries, and failure on either of these counts could risk stalling long-term production and consumption prospects. Nigeria, Venezuela, Myanmar and a number of emerging producers like Mauritania, Senegal or Ghana are all facing this challenge. Indonesia is another case in point: the geographical mismatch between new gas fields (mostly offshore) and demand hubs on Java and Sumatra needs to be bridged with infrastructure in order for gas to prosper domestically. An expansion of pipelines, LNG to FSRU options and even small-scale LNG supply via trucks or barges for smaller demand centres and outer islands, e.g. to displace costly and polluting diesel generators, is critical. However, the transmission sector currently suffers from a number of problems: extensive lead times for infrastructure planning, construction and commissioning; insufficient co-ordination between the different stakeholders and sectors (including the power sector); and physical bottlenecks.

The projections for Indonesia in the New Policies Scenario are based on the cautious assumption that such problems are gradually dealt with, and that pricing reform takes place, leading to gas demand growing from some 45 bcm in 2016 to nearly 100 bcm over the period to 2040. Industry accounts for 60% of the growth: in the power sector, gas continues to find it hard to compete against low-cost (and easily transportable) coal. Pricing reform is crucial: the anticipated abolition of preferential gas prices for certain industries creates a level playing field on the demand side while a gradual move towards export price-parity incentivises new investments in the upstream. Indonesian gas output is projected to rise by 17% to 90 bcm in 2040. As conventional gas production declines slightly to 2040, unconventional sources underpin the rise in output.

There is significant investment in conventional projects, but much of the new resources brought online in Indonesia serves to offset depletion from older fields. Although Indonesia holds, with East Natuna, Asia's largest untapped gas field, prospects for extracting this expensive and technically challenging resource (the gas has a CO_2 content of 70%) are uncertain, and clouded further by the ample availability of cheaper LNG, especially from Qatar and the United States, and later also Russia. In this edition of the *WEO*, we have not included production from this field in our projections.

Other significant gas producing countries in South and Southeast Asia – Pakistan, Bangladesh, Malaysia and Thailand – do not manage to offset the long-term decline of their mature production base with new projects. This provides a major opportunity for

LNG, as these countries have gas infrastructure in place, an established critical mass of gas consumers and experience in gas market regulation and operation. Although these countries emerge as important importers in our projections, this will require changes to domestic price regulation: LNG is a sustainable option if gas prices in these countries properly reflect its cost.

8.3.4 Trade and investment[4]

Inter-regional gas trade increases by 525 bcm in the period to 2040, expanding by 2.4% on average per year, a growth rate similar to that seen over the past 25 years. The importance of LNG in inter-regional trade grows markedly, with nearly 90% of the incremental volumes traded over long distances taking the form of LNG compared to just under two-thirds in the past 25 years. By the end of the *Outlook* period, a total of 1 230 bcm of gas is traded between regions, some 60% of which is LNG, up from just under 40% in 2016. The flexibility offered by LNG is one of the factors underpinning its growth. There are many reasons why this may be desirable from the customer's point of view. Flexibility is an important attribute for importing countries that do not want to commit to a long-term supply agreement because their main reason for procuring gas from the international market is to meet seasonal fluctuations of demand. Latin America is a case in point: the continent as a whole relies on hydropower for 45% of its electricity supply (in Brazil, the biggest power market, the figure is 65%), but hydropower is strongly weather dependent and seasonal. Gas-fired power plants balance the fluctuations but their comparably low utilisation rate often does not justify a dedicated pipeline (at least not initially) – a clear case for LNG, often in combination with an FSRU. Flexibility also plays an important role for countries that seek to temporarily supplement domestic production. Argentina is a good example; it is one of the few countries in Latin America with a significant need for heating, and therefore complements its domestic production, which is fairly inflexible, with LNG. Egypt is another example: it imports LNG to bridge the gap until output from its Zohr field has ramped up to full capacity. These are examples of countries that have good domestic production prospects and may only draw on LNG for a limited time but there are others – Malaysia, Thailand, Pakistan and Bangladesh to mention but a few – that face depletion of resources and that may rely on LNG for longer. The countries of Southeast Asia and India become a major force in the international LNG trade; the additional LNG imports of these countries add up to around 160 bcm in the period to 2040.

LNG also offers important security of supply benefits to countries that want to diversify their gas procurement portfolios. Security of supply was the primary reason for the construction of regasification terminals in Lithuania, Poland and Jordan (Croatia might follow soon). In these cases, it cannot be assumed that import volumes will be large: the primary purpose of the terminal is to provide optionality. As Jordan demonstrated in 2016, however, import volumes can surprise on the upside.

4. Unless otherwise stated, trade figures in this chapter reflect volumes traded between countries/regions modelled in the *WEO*, and therefore they do not include intra-regional trade.

Others may want LNG in order to replace oil products with cheaper gas. Such oil product displacement already makes a strong case for LNG imports in some parts of the Middle East (even though the region as a whole is a net exporter) and may underpin a growing role in the future for LNG in the Caribbean and in parts of Africa. Where ports are too shallow to accommodate large LNG tankers, LNG demand growth hinges on the availability of smaller vessels with the ability to deliver LNG cargoes. Our projections see small-scale LNG technologies advancing, and LNG gradually making inroads as a fuel for smaller countries and islands.

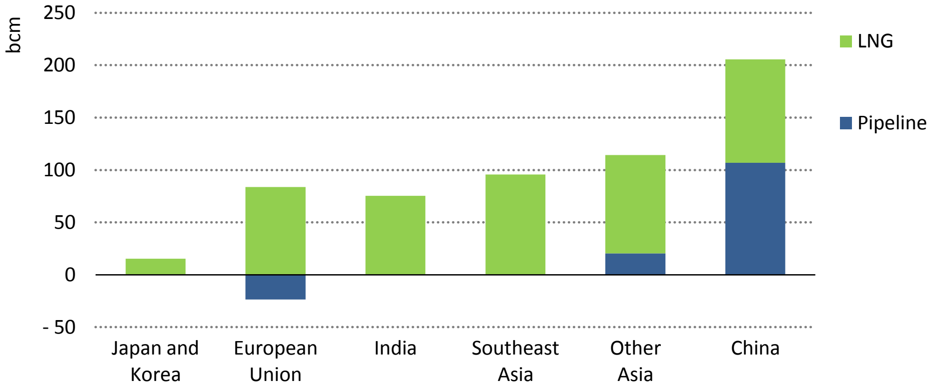
Table 8.4 ▷ Natural gas trade by region in the New Policies Scenario

Net importing regions in 2040	Net imports (bcm)			As a share of demand		
	2016	2025	2040	2016	2025	2040
European Union	-329	-374	-389	71%	80%	84%
China	-73	-177	-278	35%	44%	45%
Other Asia Pacific	52	-47	-178	17%	16%	40%
Japan and Korea	-165	-150	-181	98%	98%	99%
India	-24	-55	-99	43%	57%	54%
Other Europe	24	9	-18	16%	6%	10%
Net exporting regions in 2040	**Net exports (bcm)**			**As a share of production**		
	2016	**2025**	**2040**	**2016**	**2025**	**2040**
Russia	188	265	314	29%	37%	40%
North America	-1	119	192	0%	10%	14%
Middle East	108	134	201	18%	19%	20%
Caspian	80	87	140	40%	40%	46%
Australia	45	100	137	49%	64%	68%
Sub-Saharan Africa	29	48	106	48%	54%	50%
North Africa	42	49	47	29%	26%	19%
Central & South America	10	-6	5	6%	3%	2%

Notes: Positive numbers denote net exports and negative numbers denote net imports. Import and export totals should sum to zero; the difference in 2016 is due to stock changes.

Energy demand growth and the political will to meet this demand with a relatively clean and flexible source are the key drivers for gas import growth in China and India. No country sees its gas imports increase more than China over the coming 25 years, and total imports of 280 bcm in 2040 mean that it becomes the second-largest gas importer after the European Union (Table 8.4). Not all of these imports come from LNG (the share of LNG in Chinese gas imports stands at just under half in 2040). Although there are new links from the United States to Mexico, from the Middle East and the Caspian region to Europe, and from Iran to Pakistan, China is the only country that significantly advances large cross-border pipeline projects in our *Outlook* (Figure 8.11). By contrast, India has no planned pipelines, and it meets its additional import needs of 75 bcm in the period to 2040 entirely with LNG.

Figure 8.11 ▷ Change in gas imports by selected region and transport mode in the New Policies Scenario, 2016-2040

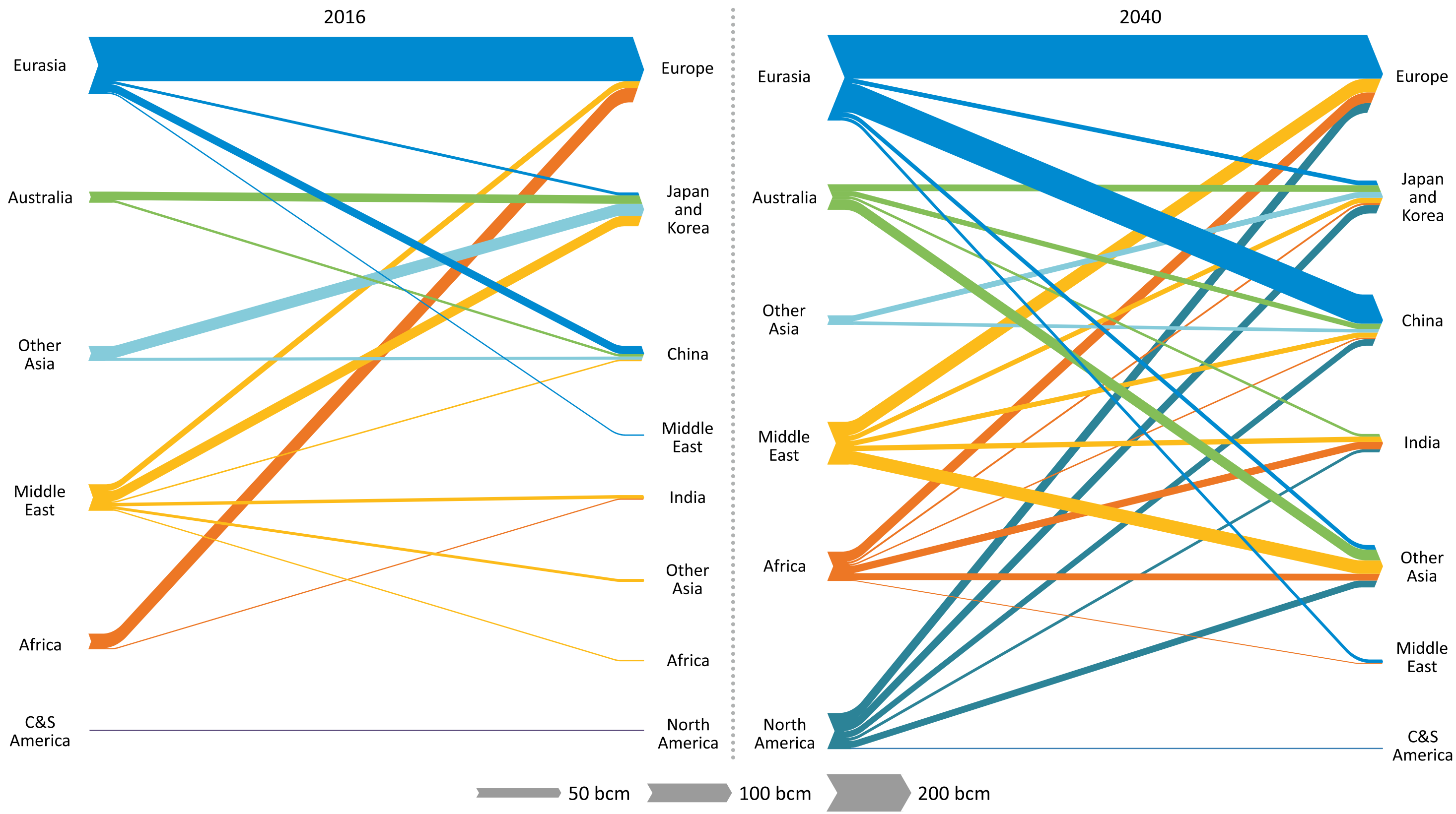


Asian countries lead the growth in global gas trade; outside China, new pipeline trade routes find it hard to advance in a market with LNG readily and flexibly available

The concentration of import growth in Asia continues to reshape inter-regional gas trade flows, underpinning a fundamental shift in the weight of trade away from the Atlantic basin to the Asia Pacific region (Figure 8.12). A growing diversity on the supply side – new exporters like the United States and later Canada and Mozambique join the club of LNG exporters – increases the interconnectivity of inter-regional gas trade. The United States, Qatar and Australia are the biggest LNG exporters in the New Policies Scenario, with the market share of the United States in inter-regional LNG trade peaking at around 25% in the mid-2020s and then declining slightly but staying above 20% for the remainder of the *Outlook* period. The global gas market not only becomes more interconnected and diverse but also sees important changes in how trade functions and how pricing is determined. These changes, and what it takes to establish a truly global gas market, are explored in detail in Chapter 9.

The global gas market is currently awash with gas, largely as a result of the rapid growth of LNG supplies and our modelling suggests that, in the New Policies Scenario, the supply overhang is not absorbed by import growth until the mid-2020s. Taking lead times of three to six years for LNG projects into account, however, new investment decisions will need to be taken soon to avoid market tightening. We see much of this investment being brought forward in the United States, Qatar and Russia in the first-half of the 2020s. The United States benefits from good conditions for brownfield investment (which keeps costs low) while Qatar and Russia have access to very low-cost gas. Projects of these three exporters have a lower risk than complex new greenfield ventures, making them well-suited for expansion at a time when the gas market is undergoing transition. In the second-half of the projection period net export growth and investment is more balanced, with more greenfield activity, for instance in East Africa and Latin America.

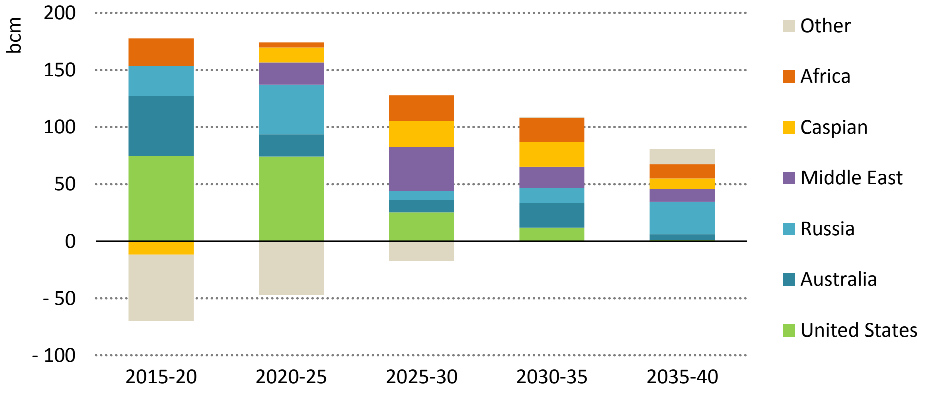
Figure 8.12 ▷ Selected global gas trade flows in the New Policies Scenario (bcm)



The rise in LNG trade underpins an increasing diversification and interconnectivity of the global gas market

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

Figure 8.13 ▷ Change in net gas exports by selected region in the New Policies Scenario



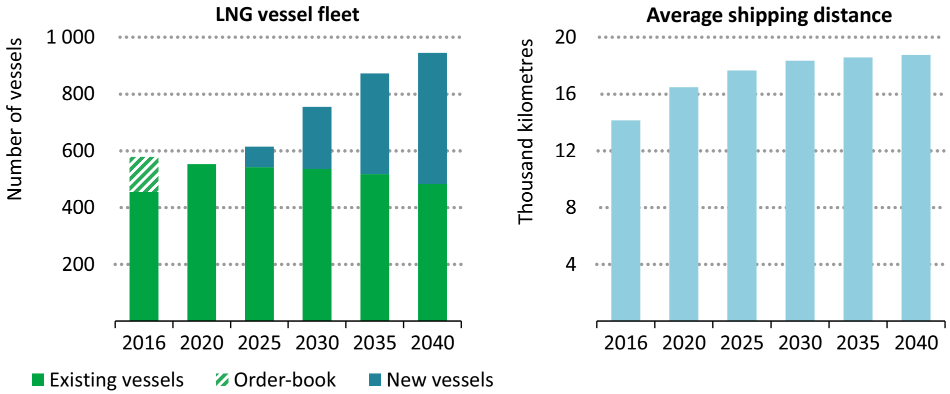
The United States, Russia and Qatar bring additional gas exports to the market in the first-half of the 2020s, fostering a smooth rebalancing

The bulk of the projects needed to meet demand over the *Outlook* period are not commercially viable at current gas price levels. This is one of the reasons why gas prices increase in the New Policies Scenario. At the same time, competition for space in the future energy mix is fierce, and investment costs need to come down if gas is to expand its share. Cumulatively, $8.6 trillion are needed in the period to 2040 for investments into the gas supply chain (upstream and midstream), accounting for more than a fifth of global supply investment in this scenario. Around a third of this investment is for infrastructure alone (transmission and distribution pipelines, liquefaction plants and regasification terminals, etc.), highlighting what a critical enabler the midstream sector is for demand growth and how disruptive constraints on infrastructure investment could be.

Focus: How is the market for LNG shipping evolving?

The LNG shipping market is currently characterised by over-capacity and low charter rates (i.e. the daily rental cost of a vessel). High and rising charter rates up to 2012 and the expectation of robust growth in LNG trade led to an ordering spree of new LNG vessels from about 2011. By the end of 2011, there were about 340 LNG vessels in operation: by the end of 2016, this number had increased to almost 460. Total LNG shipping capacity stood at around 70 million cubic metres in 2016, up 35% from 2011 levels. However, LNG trade growth fell short of expectations and, as a consequence, charter rates spiked in late-2011 before embarking on a precipitous fall, together with the utilisation rates for the LNG fleet. Average shipping distances have generally been on an increasing trend. The re-routing of LNG destined for the Atlantic market to Japan in the aftermath of the Fukushima-Daiichi nuclear accident propelled shipping distances temporarily upwards but, since 2014, shipping distances have been more in line with a gradual long-term growth path.

Figure 8.14 ▷ Evolution of the LNG vessel fleet and the average shipping distance in the New Policies Scenario



New LNG vessels are needed in the first-half of the 2020s and, with the rise of US LNG exports, average shipping distance increases

Notes: Includes only large-scale vessels (>60 000 cubic metres [m^3]). New vessels are assumed to have an average size of 172 000 m^3).

The order-book for new vessels indicates that more than 120 ships are likely to be delivered over the coming years, adding further to the size of the current LNG fleet. The current fleet is moreover relatively new (only around 6% of active LNG carriers are older than 30 years) and therefore scrappage is not likely to reduce available LNG transport capacity for a long time to come. Our New Policies Scenario, however, sees inter-regional LNG trade growing by two-thirds in the period to 2025. It also sees the emergence of the United States as a major LNG exporter boosting average shipping distances and journey durations (even with the opening of the Panama canal to large LNG tankers, the shipping distance between the US Gulf coast and Japan is up to 50% longer than from Qatar to Japan, while the distance to India is more than four-times longer than from Qatar), pushing up the utilisation of the fleet. The growth in inter-regional trade and the growing average length of journeys suggests that surplus shipping capacity will be absorbed within the first-half of the 2020s (Figure 8.14), and that more than 70 additional vessels are needed by the mid-2020s. The need for new vessels continues to grow in the long term as LNG trade keeps increasing and scrappage rates pick up with the ageing of the current fleet. By 2040, almost 950 LNG ships are travelling the world's seas in the New Policies Scenario, about twice the number of active vessels today.

The new gas order

How might LNG change the game?

Highlights

- The New Policies Scenario projects a rise of 40% in gas production in the United States to 1 060 bcm in 2040, with shale gas the main source of growth. US shale gas output increases by more than 350 bcm to 2040, adding twice the current production of Qatar to global gas supply. The bulk of the growth happens over the next ten years, and accounts for more than half of global gas output growth in that period. The ramp-up in US shale gas from 2008 to 2023 would constitute the largest increase in output from a single source in the history of gas markets.
- Annual US gas demand increases by 100 bcm over the coming 25 years, with most of the near-term growth coming from industrial consumers, but this falls well short of the huge increase in US production. Some of the amply available US shale is exported by pipeline to Mexico and Canada, but in the long term a larger share is exported in the form of LNG. Shipments of LNG from the United States surge from a low base to 115 bcm in 2025 – when the US becomes the world's largest LNG exporter – and further to nearly 160 bcm in 2040.
- US LNG has many of the characteristics – destination flexibility, hub-based pricing and spot availability – that are transforming the wider gas market and, for this reason, it accelerates structural changes in the way that gas is traded internationally.
- The new gas order is characterised by greater diversity on the supply side as the number of global liquefaction sites doubles to 2040, price formation based on competition between different sources of gas supply (oil-indexed pricing covers less than one-quarter of traded LNG in 2040, compared with 75% today); a tendency towards shorter contract durations and a greater share of spot trading; and increased contractual flexibility to seek out opportunities for arbitrage rather than trading point-to-point with a fixed group of customers.
- These changes are also underpinned by the liberalisation of gas markets in key Asian countries, which facilitates the emergence of new gas trading hubs, and by the rise of so-called portfolio players – large companies with a diversified range of supply, shipping, storage and regasification assets.
- The move towards a more diverse, flexible and liquid global gas market has important implications for investment and can bring significant benefits for energy security. In the near term, uncertainties over the market outlook and the shift in contractual and pricing arrangements are likely to favour smaller supply projects or expansions to existing facilities. The challenge for the longer term is to ensure that buyers and sellers have sufficient confidence in the emerging gas order to make it the basis for their future plans and investments.

9.1 Introduction

For decades, natural gas trade in many parts of the world has been characterised by strong bilateral ties between buyers and sellers, underpinned by binding contractual arrangements that lock them into a long-term relationship. These ties and arrangements evolved as a result of the fears of those who built highly capital-intensive pipelines that buyers might behave opportunistically once a pipeline had been finished. To mitigate such risk, sellers insisted on contracts that were long-term and included take-or-pay clauses (the buyer takes the gas or pays a penalty). Pricing was determined based on the replacement value of the gas, which in practice meant the price of oil, as the main competing fuel. Destination clauses (restricting the right to re-sell gas) prevented the buyers from seeking arbitrage opportunities and enabled price discrimination. Much of this was introduced in the early 1960s, to underpin the development of the super-giant Groningen gas field in the Netherlands. Later, these elements formed the basis for the organisation of Soviet (now Russian) gas exports to Europe.

With the rise of liquefied natural gas (LNG) trade, many of the elements that characterised pipeline-based trade were adopted for liquefied gas trade too, despite the inherently different nature of the trade relationship. Oil price indexation, take-or-pay contracts and destination clauses became common features of LNG trade in the Asia Pacific region and also of LNG trade between North Africa and Europe. As a first wave of Asian long-term contracts for LNG expired and were renegotiated in the 1990s, buyers started pushing for more flexibility such as lower take-or-pay obligations, shorter term contracts and a weakening of the oil-price linkage (the implementation of a so-called S-curve into the pricing formula reduced price volatility). But most LNG trade remained on a point-to-point basis from a specific seller to a specific buyer.

The emergence of the United States as a potential LNG importer in the mid-2000s presented a big potential market opportunity, but one that always looked likely to bring with it a challenge to the nature of the prevailing contractual arrangements. By this time, the US gas market was already highly liquid and underpinned by spot trade, so potential US gas importers were not willing to enter restrictive long-term contracts based on oil-indexed prices. Moreover, the rise of gas use in the power sector (which underwent liberalisation in many countries at that time) exposed gas to competition with coal, putting the use of oil linkage further into question. With Qatar starting to tap one of the least-cost reserves of natural gas in the North Field, the consortia developing the LNG projects were willing to accept a larger-than-usual portion of market risk and develop some capacities whose commercial fortunes would be closely tied to a growing role of spot LNG trade (both from potential buyers in the United States and the United Kingdom).

Then the shale gas revolution took off in the late 2000s in the United States, and this had marked repercussions on international LNG trade before a single cargo was imported or exported. Rapid growth in shale gas output meant that the United States would not need the large-scale LNG imports that had been anticipated. Consequently, uncontracted LNG from Qatar that had been slated for the US market (alongside other sources of LNG for instance from Nigeria, Egypt or Indonesia) needed to find a new home. In Europe, this period coincided with important gas market reforms that were aimed at improving market integration, transparency and third party access, developing bi-directional pipeline flows and increasing use of hub pricing and, from 2010, with a slowdown in gas demand. With this, the conditions were established for arbitrage between readily available cheap gas on the spot market and more costly supplies priced under existing oil-linked long-term import contracts. The combination of regulatory changes and a market awash with gas ultimately triggered a process of renegotiation of contract terms with the main pipeline exporters, chief among them Russia's Gazprom. Faced with amply available gas and depressed gas prices, Gazprom and others started to make concessions in terms of the pricing of their gas.

With US shale gas production continuing to grow robustly and prices at Henry Hub (the country's key pricing point) averaging just over $3 per million British thermal units (MBtu) over the past five years, companies in the United States started converting former LNG importing facilities into export terminals, with the intention of exporting gas based on mark-ups from domestic US prices, rather than oil. One terminal – Sabine Pass – came online in 2016 and another 70 bcm of liquefaction capacity are under construction. Together with a new wave of Australian LNG projects that continue to ramp up, nearly 140 bcm of new liquefaction capacity are set to provide exports into an already well-supplied global gas market over the next few years. This is expected to provide additional impetus for further changes in the way gas is marketed and priced, putting more pressure on the rigidities that have characterised LNG and pipeline supply arrangements in the past.

The stage is now set for the United States to move from passively influencing the LNG trade towards actively exerting influence, as it becomes one of the world's largest exporters of LNG. US LNG is available on much more flexible terms with respect to destination than gas from most other exporters. These developments are accelerating the transformation of a gas market that used to be mostly bilateral into an increasingly well-connected and liquid global market, in which price formation is based on competition between different sources of gas supply. This is uncharted territory for most of the gas industry and, while the commoditisation of gas promises to bring a better-functioning market, it brings with it a set of new uncertainties.

Will the new wave of LNG create new markets for gas, or simply re-shuffle the pack of suppliers for existing markets? What will be the reaction of Russia and Qatar, today's incumbent exporters, with some of the world's lowest-cost gas at their disposal? What will be the gas pricing benchmarks of the future, and if they do not exist already, how soon will they emerge? Are today's challenges to traditional contractual and pricing models merely symptoms of cyclical over-supply, or are changes here to stay? Is a gas market in flux capable of delivering new capital-intensive gas supply investments? These are all key questions for our *Outlook* and the answers have a profound impact on our trends and projections. Our overall judgement is that the shift towards a new gas order is long-lasting and structural. This has implications well beyond the functioning of markets and the formation of prices: it redraws the map of natural gas supply and forces a change in perspective on the gas security equation.

9.2 The US shale storm and its repercussions

With output of some 750 bcm in 2016 and a similar level of demand, the United States is the largest consumer and producer of gas in the world. A rapid increase in shale gas output has underpinned strong production growth over the last ten years. Between 2006 and 2016, shale gas production grew at an average rate of 27% per year, topping 445 bcm in 2016. During this period, the average price at the Henry Hub dropped from $6.7/MBtu in 2006 to $2.5/MBtu in 2016, although not without some ups and downs along the way. Revisions of the resource estimates have been mostly upwards in recent years, while the long-term view on US gas prices has gradually shifted in the opposite direction – this *Outlook* is no exception.

The shale gas revolution has already had profound implications for the US energy system. Much of the hardship the US coal industry is going through (see Chapter 5) and a significant share of the recent reduction seen in US energy-related CO_2 emissions (see Chapter 11) is due to the widespread availability of inexpensive shale gas. Shale gas has also displaced some pipeline gas imports from Canada and underpinned a ramp up in exports to Mexico. Facilities initially developed to import LNG are now on track to spearhead the emergence of the United States as a major LNG exporter: this will bring a further set of changes. In this section we explore the ripple effects of an upbeat view on US shale gas resources on the US energy system, impacts on energy market developments in Canada and Mexico and the repercussions for global LNG trade.

9.2.1 Production

The size of the shale gas resource and the cost of its production are the primary uncertainties for the prospects of gas production in the United States. Our modelling of US shale gas production is based on a resource estimate of 29 trillion cubic metres (tcm), some 7 tcm higher than the level that underpinned the production trends in the 2016 edition of this *Outlook*. The Marcellus – the biggest shale gas play – is at the heart of the uncertainty, but new shale gas plays such as Utica or Wolfcamp also contribute to it, and could surprise on the upside in terms of their geological quality.

The higher resource estimate in this *World Energy Outlook (WEO-2017)* is the main driver for a more upbeat projection of US shale gas production in the New Policies Scenario, but the following policy, market and technology assumptions also underpin this year's projections:

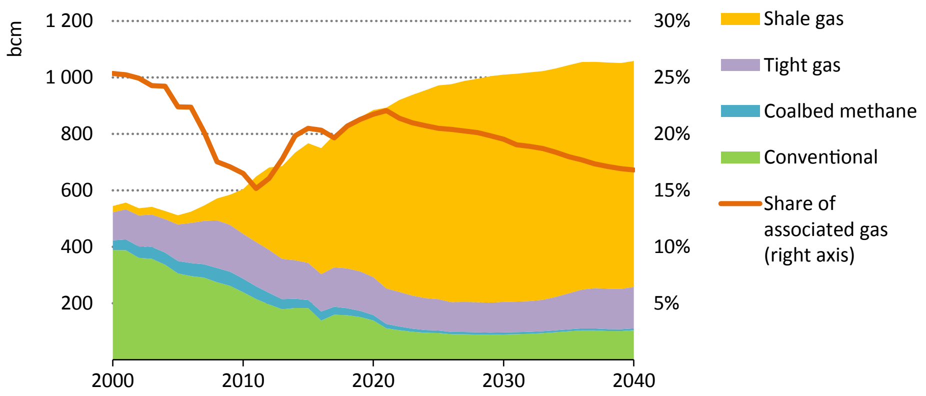
- A competitive supply chain continues to bring down the costs of production and to lead to productivity improvements, together with an improved ability to identify and target the most productive areas of the various plays, including through the systematic application of digital technologies.
- A focus on streamlining licencing provisions for new pipeline infrastructure leads to an accelerated debottlenecking of the US gas transmission network – especially in the Appalachian and the Permian Basins where production growth is concentrated.

- US tight oil production enjoys strong growth over the medium term, meaning that low-cost associated gas production expands even more rapidly.
- Major players in the oil and gas industry consolidate promising shale acreage and execute a strategic shift in capital spending, prioritising US shale gas over larger projects with long lead times.
- The easing of certain rules on hydraulic fracturing on federal land can have an impact at the margin, but is unlikely to deliver significant upside potential as the most prolific shale gas plays are under privately owned land while the main shale gas resources that are off limits for development (e.g. the Monterey in California or the parts of the Marcellus located in New York state) cannot be unlocked by federal policy.
- One crucial assumption that we have retained from previous *Outlooks* is that the industry maintains public acceptance by applying high standards in the upstream – that is, managing effectively the environmental and social issues arising from shale gas production. In our projections, hydraulic fracturing is instrumental to 90% of US gas output by 2025, up from over three-quarters today, so any loss of public trust in this process could have a major impact.

Total US gas production reaches 1 060 billion cubic metres (bcm) in 2040, over 40% higher than in 2016 (Figure 9.1). Growth is dominated by shale gas, the output of which increases by 80% in the coming 25 years, reaching 800 bcm in 2040. The ramp-up in shale gas production is particularly steep in the period to 2025; indeed, the projected increase in production would constitute the largest ramp-up in output from a single source in the history of gas markets, with a rise of over 630 bcm between 2008 and 2023 meaning a faster rate of growth than that in the Soviet Union's most rapid growth period of 1974-1989 (Figure 9.2).

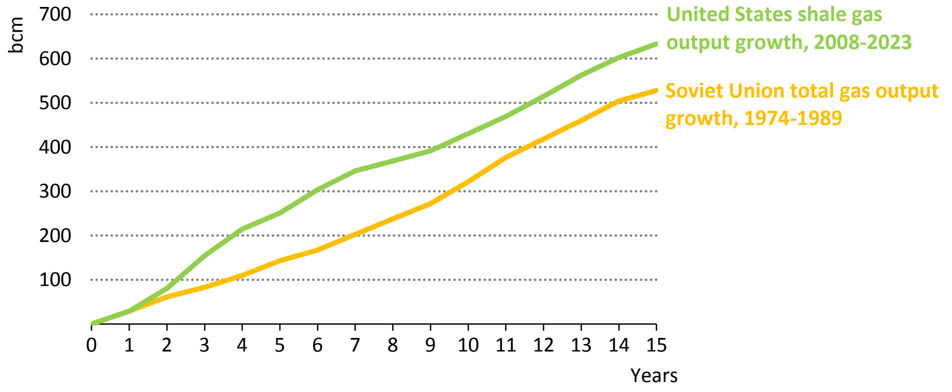
9

Figure 9.1 ▷ US gas production by type in the New Policies Scenario



Shale gas is at the heart of US gas production prospects; its share of US gas output rises from 60% in 2016 to 80% in 2030

Figure 9.2 ▷ **Rise in US shale gas output versus the steepest ramp-up in gas production in the Soviet Union**



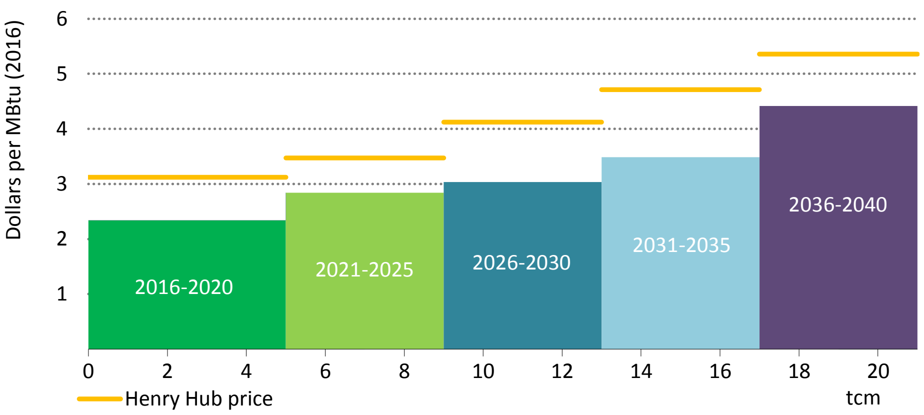
US shale growth between 2008 and 2023 is likely to be unprecedented in the history of gas markets, exceeding the growth achieved by the Soviet Union between 1974 and 1989

Although various shale gas plays contribute to this picture, the main engine of growth is the Appalachian Basin. Production from the Marcellus play in the Appalachian Basin has grown fivefold in the past five years, with output topping 170 bcm in 2016. If the Marcellus was a country, it would be the fourth largest gas producer, just behind Iran but ahead of Qatar. The Utica play – also located in the Appalachian Basin – has also started to ramp up and makes an important contribution to the long term rise in production. However, the surge in production has not been paralleled by an equal expansion in gas transmission infrastructure. As a result, gas trades at a significant discount in the Appalachian Basin compared with other pricing points in the United States, for instance the average price at the Dominion South hub stood at \$1.5/MBtu in 2016, more than \$1/MBtu below the price at the Henry Hub in that year. Timely expansion of transmission capacity, especially towards the Gulf coast and the west, is a precondition for continued strong growth from the Appalachian Basin: without it, a local glut in supply and continued discounts versus Henry Hub risk stalling investment.

Oil market fundamentals are also an important factor in our outlook for US gas production. Associated gas currently accounts for a fifth of US gas output: with the rise of tight oil production, this share has been increasing over the past few years. We see growth in associated gas output continuing until the mid-2020s, when tight oil production reaches a plateau in the New Policies Scenario, before it starts to fall back. Since associated gas is a by-product of oil extraction, it is primarily subject to oil market economics, so the growing weight of the United States in the global oil market fosters gas production growth as well. The largest tight oil play with associated gas production is the Eagle Ford (in west Texas) and the contribution of the Bakken play (in North Dakota and Montana) remains significant, but the bulk of the projected growth in associated gas production comes from the Permian Basin – also largely located in west Texas – and the Anadarko Basin[1] in Oklahoma. Producers of associated gas – especially those in the Permian – face similar challenges with pipeline bottlenecks as their peers in the Marcellus and Utica plays, especially over the coming ten years. Transmission capacity expansion from the Permian focuses on exports to Mexico and shipments towards the Gulf Coast, while additional production from the Anadarko Basin is primarily geared towards domestic consumption in the central United States.

Shale gas production trends are sensitive to the prevailing price level. In our modelling, current price levels of around \$3/MBtu at the Henry Hub are insufficient to deliver the incremental production projected in the New Policies Scenario. Henry Hub prices thus rise gradually to \$3.7/MBtu in 2025 and then to \$5.6/MBtu in 2040. There is ample availability of relatively low cost gas in the United States and the upward revision of the resource estimate has led to a more optimistic assessment of the size and number of sweet spots, i.e. the economically most attractive portions of a shale gas deposit. Nonetheless, as the United States works through its shale gas resource base, producers are forced gradually to move away from the sweet spots to less productive zones. Continued technology learning and innovation mitigate the effect of this move on the economics of shale gas. Overall, however, the cost of new resources developed gradually increases and puts upward pressure on gas prices (Figure 9.3).

Figure 9.3 ▷ Average costs of resources developed in the New Policies Scenario by year and average Henry Hub price



As production moves to less productive zones and as associated gas output levels off, the average cost of new resources developed increases, putting upward pressure on prices

1. Primarily the South Central Oklahoma Oil Province and Sooner Trend Anadarko Basin Canadian and Kingfisher Counties (SCOOP and STACK) plays.

In the New Policies Scenario, over 20 tcm of shale gas resources is developed over the next 25 years in the United States. Even though not all of this is produced by 2040 (some of the developed resources have a production profile stretching beyond the time horizon of our *Outlook*), the competitive forces in the US gas industry, in combination with private resource ownership, lead to development of shale resources at a speed that is faster than in those countries where governments have defined specific policies on resource depletion (see section 9.3.4).

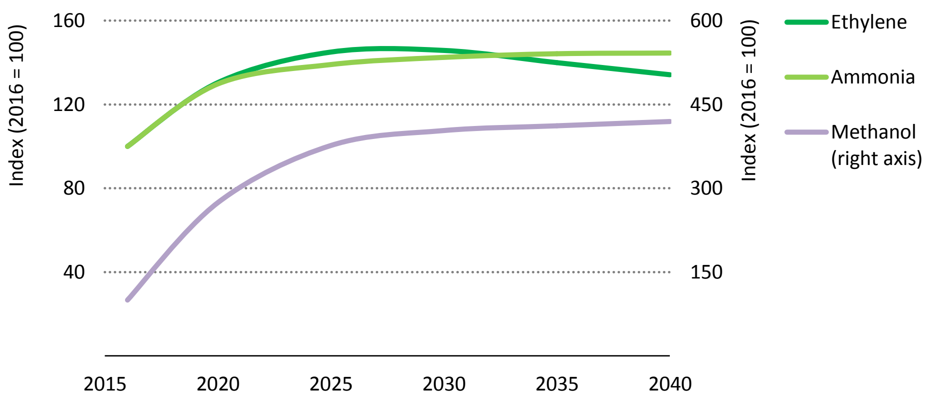
9.2.2 Implications for North America

Gas consumption in the United States – the world's largest gas consumer and a mature gas market – increases from 780 bcm in 2016 to 880 bcm in 2040, at an annual growth rate of 0.5%. Although gas slightly increases its contribution to primary energy supply from 30% in 2016 to 34% in 2040, there are limits as to how much further gas can increase its share in the US energy mix. The power sector is a case in point: the low gas prices seen over the past few years have led to an unprecedented fuel switch from coal to gas. In 2016, for the first time in US history, more electricity was generated from gas than from coal. But price sensitive fuel switching in power generation can cut both ways, and a relatively small increase in the Henry Hub price level could lead to some switching back to coal (as has been observed in the US in the first-half of 2017). The projected increase in Henry Hub prices to $3.7/MBtu in 2025 therefore limits the space for gas-fired power generation to grow in the first-half of the *Outlook* period: so does robust growth in renewable energies (for which many incentives remain in place at federal and state level); and the assumed removal of the Clean Power Plan (without it, coal-fired power plants have no CO_2 emissions constraint and can achieve higher utilisation rates in states where coal is cheaper than gas – see Chapter 5). In addition, demand growth for power slows to 0.7% per year on average in the period to 2040, whereas it was twice as fast over the past 25 years.

The production of certain chemicals (such as ammonia or methanol) uses natural gas as a feedstock while the production of base-chemicals (such as ethylene or propylene) relies on natural gas liquids. As the production process is not very labour intensive, the cost and availability of feedstock are critical for the commercial viability of such petrochemical facilities. The rapid increase in shale gas production has given the United States some of the lowest gas prices in the world and resulted in a glut of natural gas liquids, especially ethane. This has provided a boost to the petrochemical industry in the United States, triggering a large expansion of production capacity. For instance, in the period to 2025, we project the addition of some 13 million tonnes of new ethane cracking capacity in the United States, which accounts for 30% of the global additions in this period. With US ethane crackers enjoying a clear cost advantage over naphtha crackers elsewhere, US exports of base chemicals increase markedly over the projection period. Most of the growth is expected to come over the next decade: reduced availability of natural gas liquids in the second-half of our projection period constrains further expansion.

Despite a gradual increase over time, US gas prices remain among the lowest in the world in the New Policies Scenario, which also spurs growth in the production of ammonia and methanol (Figure 9.4). As with ethane crackers, there is a well-stocked investment pipeline for ammonia and methanol facilities in the United States, with the bulk of the capacity additions likewise expected over the next decade. In the period to 2025, the use of gas as a feedstock for the US petrochemical industry more than doubles to over 19 bcm, accounting for over a quarter of the worldwide increase in gas feedstock use, and it continues to grow over the longer term to 2040. Much of the growth is export-driven: ammonia and methanol are cheaper and easier to transport than LNG, and there is a strong incentive to export the final product as well as the feedstock.

Figure 9.4 ▷ Indexed production growth of selected chemicals in the United States in the New Policies Scenario

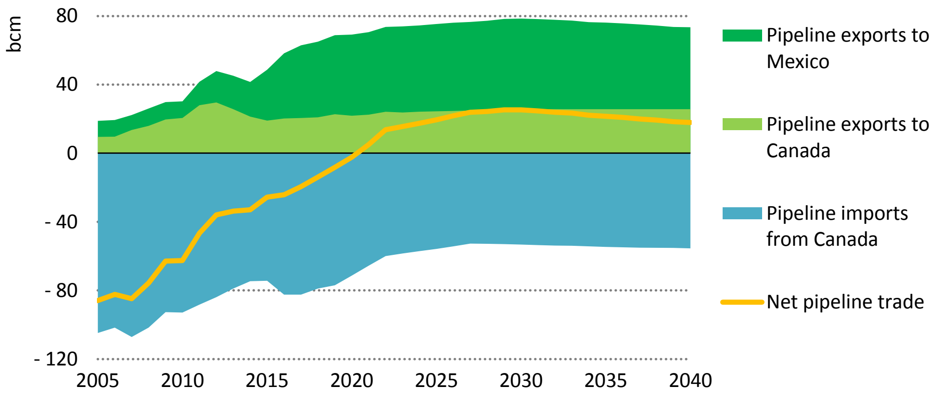


The shale gas boom and the ready availability of natural gas liquids underpin strong near-term growth in US petrochemicals output

Despite US gas prices being some 20% lower in this year's edition of the *WEO*, gas demand in the United States is only slightly higher – an additional 30 bcm in 2030 and 40 bcm in 2040 – than in last year's *Outlook*. What may seem counterintuitive at first glance is the result of a number of forces pushing in different directions that almost offset each other. Unsurprisingly, lower gas prices provide a positive stimulus for gas demand – especially in the power sector and in industry – but the absence of the Clean Power Plan (which is the main policy change compared with last year's *Outlook*) provides some upside to coal in the power sector, while a slight downward revision in the International Monetary Fund's economic outlook (a key element of our medium-term modelling) takes the edge off energy demand in general and industrial activity in particular.

Developments in the US gas market have repercussions for the neighbouring Mexican and Canadian gas markets too, as they are part of an increasingly interconnected North American transmission system. In 2005, the United States imported over 100 bcm from Canada, but the rise in shale gas production and the drop in prices have led to shipments from Canada falling by over a fifth in 2016 (Figure 9.5). Over the same period, US gas companies ramped up their exports to Canada and Mexico, pushing net US imports of pipeline gas down to around 25 bcm in 2016, compared with 80 bcm some ten years earlier. We project a continuation of these trends: imports from Canada keep falling, increasing amounts of US gas find their way to Mexico and by around 2020 the United States switches from being a net importer of pipeline gas to a net exporter.

Figure 9.5 ▷ US pipeline gas trade by destination in the New Policies Scenario

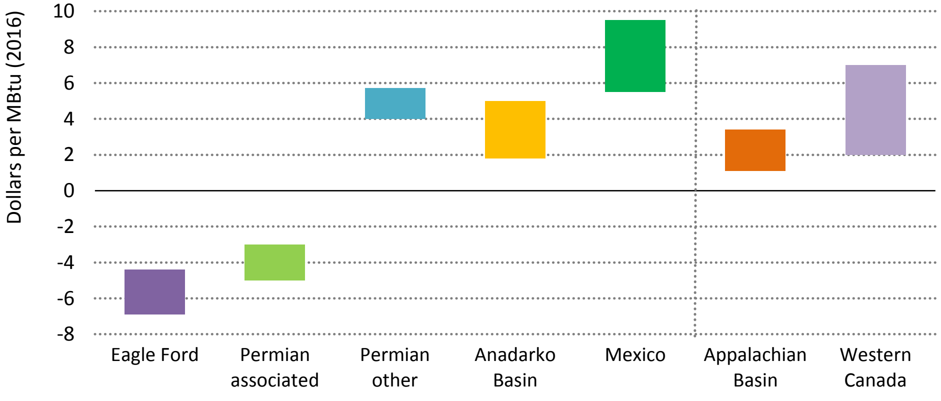


The availability of cheap gas turns the United States into a net-exporter of pipeline gas as imports from Canada decline and shipments to Mexico ramp up

Gas producers in the southern United States have the advantage of being close to the rapidly growing Mexican gas market. Economic growth and substitution of oil in various sectors of the Mexican energy system (mainly power generation and industry) underpin gas demand growth of 1.1% per year over the next 25 years – a growth rate that is twice as high as that of the United States. As of September 2017, there were 17 cross-border pipelines with a combined annual capacity of around 50 bcm in operation between Mexico and the United States, and a number of pipeline projects adding up to over 30 bcm are at an advanced stage of realisation. As pipeline expansion for the transportation of shale gas (especially from the Permian) progresses in the United States, there is scope for export growth to Mexico.

The future balance in Mexico between imported and domestically produced gas depends on a range of market and policy factors – and a key uncertainty is the extent to which Mexico pursues development of its large unconventional gas resources. Mexico does have strong potential for shale gas development (for instance, the prolific Eagle Ford play extends across the border) but the Mexican shale gas industry and supply chain are still at a very nascent stage. With US gas prices staying below $5/MBtu through the mid-2030s, importing gas from the United States remains attractive, and there is limited incentive to develop shale gas in Mexico for much of our *Outlook* period (Figure 9.6). Only in the 2030s – as costs in the United States start increasing – do we project shale gas production to pick up significantly in Mexico. By 2040, Mexico produces nearly 60 bcm of gas, of which a fifth is shale gas.

Figure 9.6 ▷ Indicative well-head breakeven cost of various shale gas plays in North America



Surging production of inexpensive shale gas in the United States delays development of more costly resources in Canada and Mexico

Notes: Negative well-head breakeven costs for the Eagle Ford and Permian plays are due to natural gas typically being a by-product of oil production in these plays. In this case, the revenues of the oil sales would be high enough to justify production of oil even if the associated gas had a negative value. Although associated gas may essentially be free at the well-head, there are still costs from its gathering, processing and transportation.

Canada has been a major gas exporter to the United States for decades. Canadian gas production is primarily located in the Western provinces of Alberta and British Columbia and has been serving US gas demand in the West, the Midwest and the East. However, the rise in shale gas production in the Appalachian Basin has reduced the call on imported gas in the eastern United States. In 2005, exports to the eastern United States accounted for some 30% of total Canadian pipeline exports to the United States, but this figure fell to just over 10% in 2016. The lower gas prices prevailing in the US market continue to impact Canadian pipeline gas exports over the *Outlook* period. For instance, the Rockies Express Pipeline, which was initially designed to transmit gas from the Western US and Canada to Ohio, was recently turned into a bi-directional pipeline; and construction has started on the Rover pipeline, which will bring gas from the Appalachian Basin to the Midwest and Ontario province. As a result, Canadian pipeline exports drop to around 55 bcm in the mid-2020s and flatten out at that level, while US pipeline gas exports to Canada increase to around 25 bcm. A larger expansion of gas exports to Eastern Canada from the Appalachian basin could even see the United States becoming a net exporter to its northern neighbour.

The abundance of shale gas in the United States also affects the pace of shale gas development in Canada (see also Box 9.1). Although Canada has potentially prolific shale gas plays, especially the liquids-rich parts of the Montney and Duvernay plays and the Horn River play (all located in western Canada), their estimated development cost is higher on average than in the Permian or the Appalachian Basin and they are further away from the demand hubs. Canadian gas production nevertheless increases markedly, reaching 220 bcm in 2040, up from 175 bcm in 2016. Shale gas is the primary source of Canadian gas production rising from 5 bcm in 2016 to over 150 bcm in 2040, but new development remains concentrated on the low-cost areas of the Montney play, with significant uptake in production from the remote Horn River pushed beyond the time horizon of our *Outlook*. A significant ramp-up in Canadian LNG projects takes place only in the 2030s (later than projected in the *WEO-2016*), with LNG export volumes reaching some 35 bcm by 2040.

Box 9.1 ▷ How the success of US shale may postpone the revolution elsewhere

It is sometimes assumed that the success of shale in the United States presages an early worldwide shale gas revolution, with other countries picking up or importing the technologies and know-how that will help them develop their own shale gas resources. But the examples of Canada and Mexico suggest a different possibility, which is that the very success of US shale may ultimately serve to hold back the prospects for successful shale development elsewhere. The shale resources in both countries hold considerable promise, but the incentives to invest in their production are diminished when wholesale prices remain low.

The same logic applies, albeit in slightly more diluted form, to more distant shale resources from Argentina to China and beyond. Outside the United States, shale remains a relatively high-cost, poorly-understood resource that poses challenges stretching from access to land and availability of water to bureaucratic hurdles. A critical mass of activity and learning is necessary to generate economies of scale and bring down breakeven prices. But getting the momentum going for this is tough. At least for the next ten years, and largely because of the success of US shale, gas is readily available at a price that limits the economic incentive to pursue shale elsewhere. As a consequence, the share of the United States in global shale output stays very high: from close to 100% today it remains at more than 90% in 2025, before tailing off to 65% in 2040 as US production falls back slightly and momentum picks up in other countries.

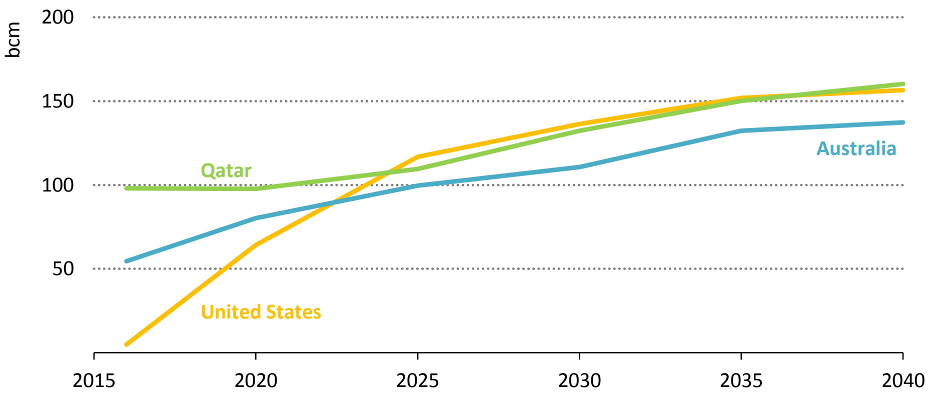
9.2.3 Implications for global market dynamics

As the North American market is not sufficiently large to absorb the very steep rise in US gas production, the stage is set for US gas to be exported elsewhere in the form of LNG. There is one LNG export facility in operation, at Sabine Pass in Louisiana, another six under construction and some 40 in various stages of realisation.[2] By 2025, US liquefaction

2. Another LNG plant, in Alaska, has been operational for decades but follows different market dynamics.

capacity is projected to reach 140 bcm, and it keeps growing thereafter to over 170 bcm in 2040. US exports grow rapidly following this ramp up in liquefaction capacity, making the United States the largest exporter of LNG in the world by the mid-2020s. Exports keep on growing after 2025, albeit at a slower pace, reaching over 160 bcm in 2040 (Figure 9.7). This leads to a jump in the market share of US LNG exporters in global LNG trade to a quarter in 2025 – a share that drops to around a fifth at the end of the *Outlook* period. Asia – with Japan, Korea, China and India at the forefront – is the primary outlet for US LNG exports although the Atlantic basin provides important markets in Europe and parts of Latin America too, especially in the coming decade (Figure 9.8).

Figure 9.7 ▷ Selected LNG exports in the New Policies Scenario

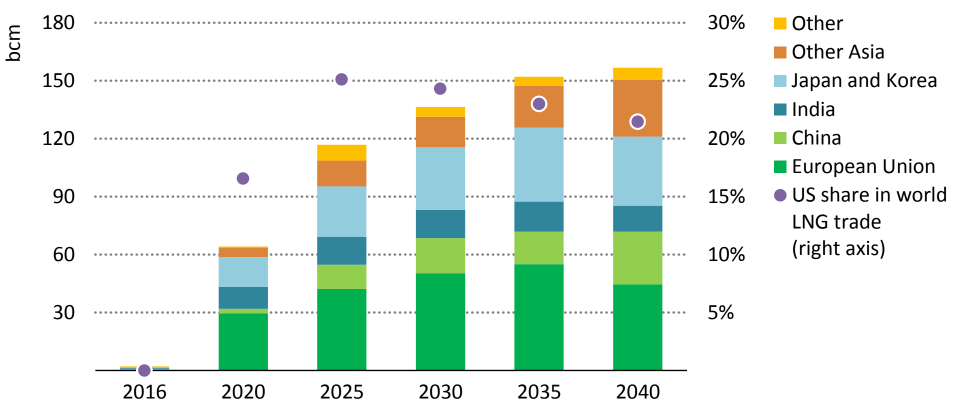


In the mid-2020s, the United States becomes temporarily the world's largest exporter of LNG

While most LNG export facilities around the world are part of integrated projects, with the export terminal being connected to a dedicated upstream source that provides the feed gas, most US LNG projects are based on a different business model and draw their gas directly from the US gas transmission network. The cost of the feed gas for a typical US project corresponds to the gas price at the nearest hub (plus transport costs) and the full delivery cost of a typical US LNG shipment therefore consists of the feed gas (plus a mark-up of typically around 15%), a fee for the use of the liquefaction facility (the so-called tolling fee), and the seaborne transport cost to the importing country.

In most cases, the off-taker of the gas from a US LNG facility is a different entity from the owner of the facility, but not the final customer, so liquefaction – booked and paid for on a long-term take-or-pay basis – becomes a self-contained midstream investment and the off-taker takes all responsibility for finding an eventual consumer for the gas. But there are interesting variations emerging on this theme. Some major gas marketers are also investing in liquefaction, as for example at the proposed Golden Pass project in Texas that is backed by Qatar Petroleum and ExxonMobil. Some US terminal operators are also getting more involved in the marketing side, for example with Cheniere (developer of the Sabine Pass and Corpus Christi liquefaction facilities) selling some LNG directly. And some US exporters are even moving away from the pricing model based on mark-ups from Henry Hub, taking some of the eventual price risk away from the buyers: the most notable example is the offer made by Tellurian to deliver gas from its proposed Driftwood LNG project in Louisiana to Asian markets at a fixed $8/MBtu price under five-year contracts from 2023.

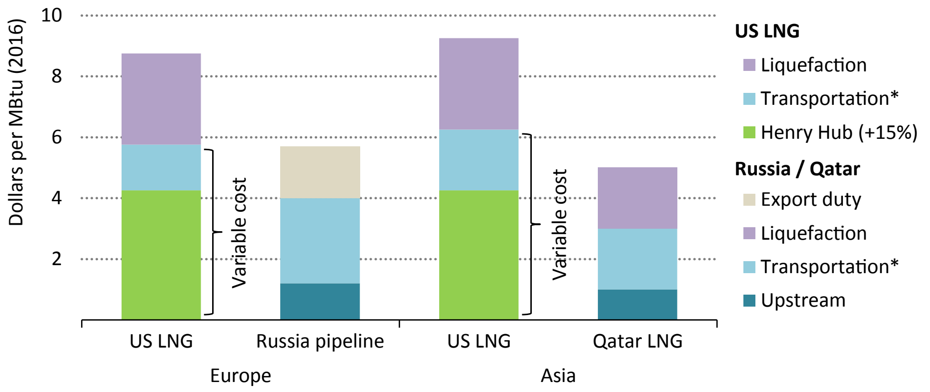
Figure 9.8 ▷ US LNG net exports by destination and market share in the global LNG trade in the New Policies Scenario



The United States becomes a heavyweight in the global LNG market, providing more than a fifth of traded volumes in the long term

Based on a Henry Hub gas price of $3.7/MBtu (the price in the New Policies Scenario for 2025), we estimate that US LNG could find its way to Europe or Asia at a full delivered cost of around $9/MBtu. (Figure 9.9). This suggests that US LNG should not necessarily be viewed as a low-cost source of supply, once all costs are taken into account. Broadly speaking, LNG exports from the United States are likely to come in as a wedge between low-cost supply projects (for instance, in Russia and Qatar), and more costly greenfield projects in various parts of the world. However, the large US gas market that feeds LNG exports can provide substantial additional LNG exports without a marked rise in prices so there is plenty of it available at a cost that many aspiring LNG exporters are likely to find hard to beat. Moreover, the conditions are favourable for an expansion of liquefaction capacities – often in the form of relatively low-cost brownfield projects – should the market call for them (see section 9.3.3). US LNG thus provides a long term price anchor in the international gas trade, an important factor for our gas price outlook (see Chapter 1).

Figure 9.9 ▷ Delivered cost of different sources of gas to Europe and Asia, 2025



Beating the delivered cost of Russian gas in Europe or Qatari gas in Asia is a tall order for US LNG

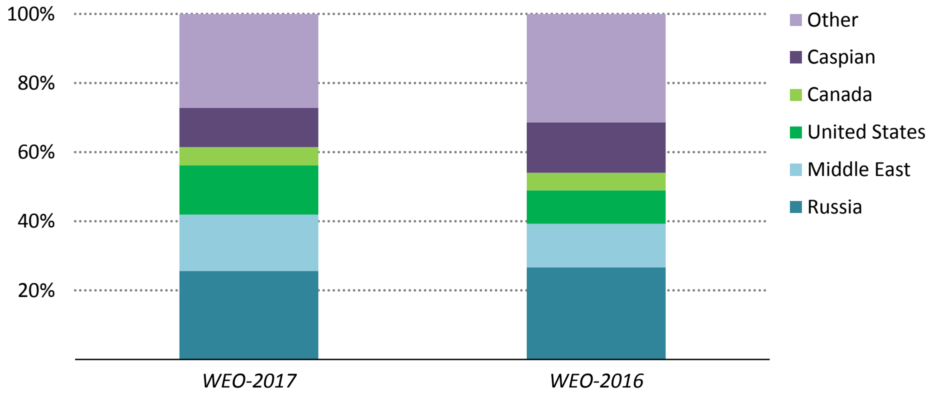
* Transportation includes regasification cost for LNG.

Compared with last year's *Outlook,* in which the United States did not surpass a market share of 10% of long-distance gas trade[3] by 2040, this edition of the *WEO* presents a significant change in trends (Figure 9.10). This has three interrelated implications for gas trade:

- US LNG comes in at a lower cost than many of the projects needed to meet gas demand in the 2016 *Outlook*. As a result, the development of some high-cost or technically challenging supply projects (some Canadian LNG, second wave Australian LNG projects or East Natuna in Indonesia) is delayed or pushed beyond the time horizon of our projections.
- Lower prices for internationally traded gas stimulate demand and also defer some production in major importing regions (e.g. in Pakistan, Bangladesh, India and China), meaning that the volume of gas traded over long distances (1 230 bcm in 2040) is some 10% higher than in our 2016 edition.
- A well-functioning and liquid LNG market makes complex long-distance pipeline projects less attractive, delaying or deterring expansion of some export-oriented gas production (for instance, in this *Outlook* we assume that large-scale pipeline connections from the Caspian or the Middle East to South Asia are not built within the next 25 years, while some other projects to Europe and China are delayed).

3. Unless otherwise stated, trade figures in this chapter reflect volumes traded between countries/regions modelled in the *WEO* (inter-regional trade), and they do not include gas trade within these regions.

Figure 9.10 ▷ Market shares in inter-regional gas trade by exporter in *WEO-2017* and the *WEO-2016*, 2040



An upbeat view on US gas exports implies a downbeat view on the development of various costly, technically challenging or remote projects around the world

9.3 The emergence of a new gas order

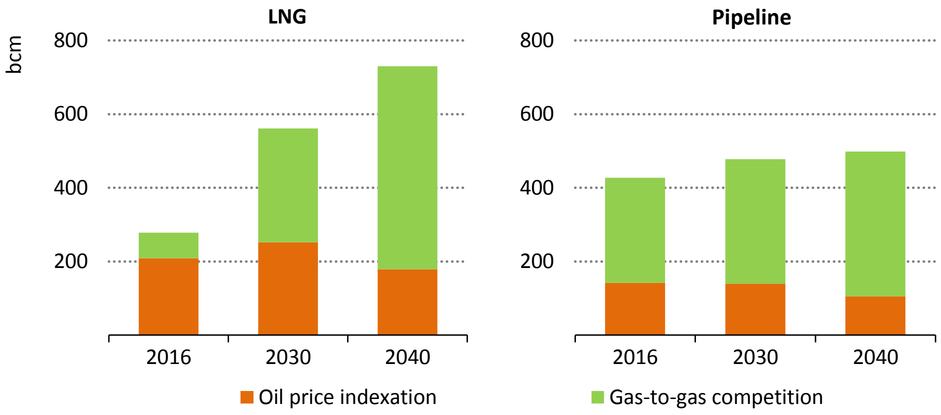
The way gas is traded internationally is changing. Destination flexibility, pricing based on gas-to-gas competition, a rise in spot deals and shorter contract durations have gradually made inroads into global gas markets. New exporters such as Australia, Angola, Papua New Guinea or Peru have come onto the stage over the past few years, increasing LNG supplier diversity, and within the next few years others such as Cameroon and Mozambique are set to join them. However, the biggest push towards a more competitive gas market comes from the rapid and large-scale ramp up of LNG from the United States, which has many of the characteristics – flexibility, hub-based pricing or spot availability – that are transforming the wider gas market. So the US gas industry is not just exporting growing volumes of gas over the next 25 years, it is also giving additional impetus to a major shift in how gas markets are organised and how trade is conducted. This has far-reaching implications for future gas markets and security of supply, accelerating a transition towards a truly global gas market.

9.3.1 Pricing of gas

Gas pricing can take various forms and the preferred method varies regionally. Gas-to-gas competition is now the most widespread form of pricing mechanism globally, used for around 45% of gas sales, followed by regulated prices (30%) and oil price indexation (20%) (IGU, 2017). Virtually all gas that is bought and sold in North America is subject to gas-to-gas competition, and in Europe some 65% of the gas trade is based on this pricing mechanism (more so in Northwest Europe, less so in the Mediterranean and Southeast).

In Asia, oil price indexation is the dominant pricing method, used for nearly 70% of gas sales in 2016. Regulated gas prices are not uncommon across the developing world but are most widespread in the resource-rich Middle East, where some three-quarters of gas sales are regulated. Oil-price indexation prevails in the LNG market where three quarters of the sales volumes are based on the price of oil (a share that has been largely constant over the past five years as most of the LNG trade growth materialised in regions where alternatives to oil-linkage are still scarce). In cross-border pipeline trade, pricing based on gas-to-gas competition has gradually increased its share, at the expense of oil-price indexation, to 60%, up from around 35% five years ago (Figure 9.11).

Figure 9.11 ▷ Global long-distance gas trade by transport mode and pricing method in the New Policies Scenario



In Asia, US LNG sparks a transition of LNG pricing away from strict oil price indexation

Note: Traded volumes of gas based on hybrid pricing formulas are split proportionally according to the estimated shares of oil price indexation and gas-to-gas pricing.

The way gas is priced is expected to change substantially over the *Outlook* period. The gradual removal of fossil fuel subsidies in gas exporting countries leads to the introduction of market-based elements of price formation in the Middle East and Southeast Asia. Similarly, gas market reform in China, expected to progress in the first-half of the *Outlook* period, leads to a larger share of market-based pricing there (see Chapter 14). But the changes in gas pricing are most pronounced and far-reaching in international gas trade. Europe has already been witnessing a marked shift away from oil-price indexed imports, with pipeline gas increasingly traded at prices determined at the European hubs (see also Box 9.2). The combination of a demand shock (in the aftermath of the 2008-2009 financial crisis), a surge in the availability of LNG and progress in the development of the EU internal gas market (the Third Energy Package) led to a gas glut in Europe in the late 2000s, forcing pipeline gas suppliers to adapt their pricing terms. This trend is set to continue over the *Outlook* period, as growing volumes of US LNG, the price of which follows the fundamentals of the US gas market, flow onto the global market and maintain the pressure on other European suppliers, notably Russia, to move towards hub-based pricing (see Spotlight).

S P O T L I G H T

Will Europe become the battlefield of a price war?

Russia provided 43% of the European Union's gas import needs in 2016, and plays a central role in Europe's gas market. Although the revenues it earns from gas are much smaller than those from oil exports, they are still very important for Russia's budget. The emergence of the United States as a major LNG exporter with the ability and ambition to export to Europe could lead Gazprom (which retains a monopoly on Russian pipeline gas exports) to react. Gazprom has a strong competitive position in the European market: existing long-term contracts of up to 100 bcm in 2025 (at 70% take-or-pay level), low production costs, more than 150 bcm of spare gas production capacity, and plenty of pipeline export capacity to Europe. Gazprom has the means to keep US LNG exports to Europe at bay. But will it choose to do so?

In the short run, variable supply costs are the relevant factor in determining whether a company should sell gas at a given price. The variable costs of US LNG add up to some $6/MBtu, in 2025, for deliveries to Europe. Russia's variable costs depend to a large degree on the value of the rouble, but it is reasonable to assume that Gazprom can comfortably supply gas at the level that matches US imports and even undercuts them. If Gazprom chooses to lower its price, however, it gains market share but reduces the value of its gas sales – a strategy that can only be profitable up to a certain point. Where exactly this point is depends on a range of considerations, but in our view a price war that brings European gas prices down to the variable costs of US LNG exports is not in the interest of either Gazprom or US exporters. Nor is such a strategy commercially sustainable in the long term: neither Russian nor US companies are likely to bring new supplies on stream if they cannot recoup the full cost of their existing assets. If a price war were to unfold in Europe, it would also be a sign of collective failure of the LNG industry to unlock new demand in more profitable markets. Cut-throat competition in Europe is thus likely to be a last resort.

The New Policies Scenario is based on the assumption that Gazprom will accommodate some US LNG in the growing European import market in order to keep prices at a sustainable level. Russian exports to the European Union stay flat at just under 150 bcm over the period to 2040, and Russia keeps its market share at around 40%. US LNG reaches a market share of some 12% in the early-2030s but this then falls as US LNG exports are gradually rerouted to the more profitable Asian market. The competition between Gazprom and US exporters brings significant benefits to consumers, helping gas to maintain its foothold in the European energy mix.

Box 9.2 ▷ What's the problem with oil price indexation?

In the early days of the gas industry, linking the price of gas to that of oil was an effective way to incentivise investment in major gas projects, while helping consumers to manage the price risks of switching away from oil. Gas markets look different today: the primary competitor for gas is often now coal, and – as the example of North America makes clear – a well-functioning gas market, with prices determined by competition between various sources of gas, can offer sufficient incentive for very large-scale investments.

Oil and gas markets have diverged in recent years, and therefore linking the price of the one to the other calls into question the most important function of prices, namely, signalling scarcity and triggering timely investment where and when it is needed. It cannot be taken for granted that gas-to-gas competition generally delivers lower prices than oil-indexation but it certainly delivers "correct" prices in the sense that they reflect the value of gas, not that of another product. If, as is the case in our New Policies Scenario, oil prices rise faster than gas prices, this puts strains on the system as those buyers locked into oil-indexed gas contracts face economic hardship and seek ways to benefit from cheaper spot gas. If on the other hand oil prices were to stay lower for longer, oil-indexed prices would suggest ample availability of gas at a time when new investment was needed.

Well-functioning gas markets therefore require a price that reacts to changes in the supply-demand balance for gas (which is not the case if prices follow fluctuations in the oil market), but a competitive gas market does not follow automatically from a switch in pricing mechanism. Important prerequisites for gas-to-gas competition include the existence of various sources of gas supply that can actually compete in a market and the possibility for buyers to re-sell and ship the gas within their market to other buyers. LNG, which is inherently more flexible than a bilateral pipeline, can stimulate competition, but this needs to be complemented in gas-importing markets by gas market liberalisation and the development of liquid and transparent pricing points.

Although oil price indexation is still deeply entrenched in gas trading in Asia, the region could soon replicate the conditions that triggered the shift away from oil-price indexation in Europe. In our projections, the oil price increases to just under $85 per barrel in 2025 and to around $95 per barrel in 2030, and this rise in prices puts upward pressure on oil-indexed gas prices.[4] Our projections suggest that US exporters will be able to supply the Asian market at lower prices than are likely to result from many such oil-indexed gas prices, giving US exporters substantial headroom in the Asian market to undercut oil-indexed gas contracts, and putting the suppliers who use them under pressure to amend them.

4. For instance, an oil price of $90 per barrel, in an oil-linked contract with a slope of 13% and a constant of $0.8/MBtu, would mean a delivered gas price of $12.5/MBtu. The US gas price, however, remains below $4/MBtu in 2025 and reaches $4.4/MBtu in 2030, suggesting that US exporters can supply to the Asian market at less than $10/MBtu in that time frame.

The liberalisation of gas markets in Japan and China and their introduction of third-party-access is set to boost the number of buyers that can purchase competitively-priced LNG on the short-term market and undercut the position of those whose gas is procured at higher oil-linked prices. This implies strong pressure to loosen the contract terms either via renegotiations (or possibly, as was the case in Europe, via litigation). The shift from a seller's to a buyer's market has already given rise to a number of cases of contract renegotiations: a prominent example is Petronet (a major Indian LNG buyer) which succeeded in convincing RasGas (a key gas exporter from Qatar) to make concessions regarding the oil linkage and take-or-pay provisions in its long-term contract. An important enabler for the move away from strict oil-price indexation in Asia is the development there of at least one liquid and transparent pricing reference point or a recognised gas hub (Singapore, Japan, Shanghai and Chongqing are all viable candidates with different advantages and disadvantages).

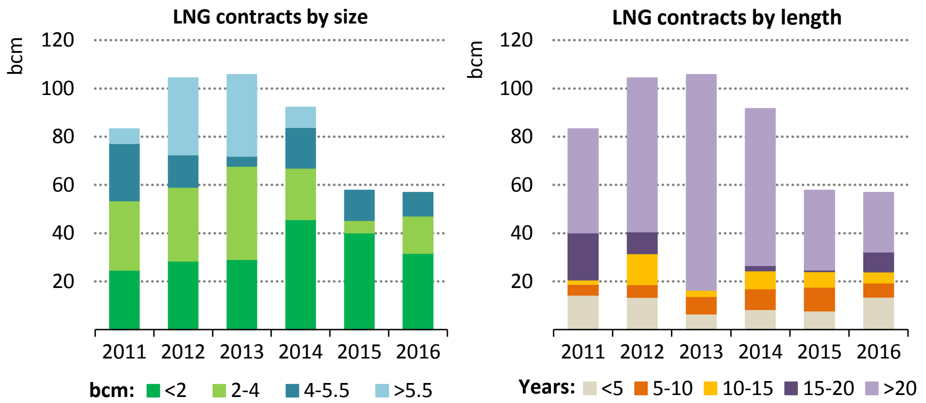
By 2040, our estimates in the New Policies Scenario suggest that more than three-quarters of LNG trade worldwide is based on gas-to-gas competition. What is left in terms of oil-indexation at the end of the *Outlook* period are mostly legacy contracts concluded through to the mid-2020s, with very few contracts concluded in the 2030s still based on strict oil indexation (although this would not exclude some hybrid pricing formulas, in which references to oil product prices co-exist with hub-based pricing, as companies look for a balanced way to manage risks in some markets). The evolution for pipeline trade is not as straightforward. Pipeline imports in Europe rapidly move towards prices set by gas-to-gas competition, but new pipeline projects in Asia (e.g. connections between China, Russia and the Caspian region) often lack a viable alternative to oil linkage: the development of liquid gas trading hubs in China is not assumed to be accomplished before the mid-2020s. The share of oil-price indexed gas trade does not drop as rapidly as for LNG.

9.3.2 Contracts in gas trade

International gas trade is dominated by contractual supply and offtake agreements that specify the duration and the size of the gas delivery and often come with a number of additional terms such as destination and take-or-pay clauses. Destination flexibility can also be implicitly restricted by a delivery ex-ship agreement, which does not restrict the right to resell the gas but requires the gas to be first unloaded (i.e. regasified) and then reloaded (i.e. liquefied) before it can be sold to another buyer, which is expensive. Only if the LNG is sold on a free-on-board basis can the buyer easily re-route the vessel to another destination.

The current glut of LNG and the slowdown in approvals of new large-scale supply projects is reflected in changes in the duration and size of recently concluded contracts. Over the past three years, fewer consumers committed to long-term gas offtake, underpinning a trend towards shorter contract duration (Figure 9.12). This trend has triggered an uptick in spot trade, although the volume of gas spot trade sales is still small compared to spot sales in oil and coal markets. Contracts have also become smaller in terms of volume, indicating that consumers are wary about committing themselves to large amounts of future gas supplies.

Figure 9.12 ▷ **Total volume of LNG contracts concluded between 2011 and 2016 by size and duration**



Recent LNG contracts have tended to be much shorter in length and smaller in size than previous ones

Destination clauses are under attack from various sides. After the European Commission found destination clauses to be incompatible with European competition law in the early 2000s, Japan's Fair Trade Commission has now concluded that such clauses are potentially also at odds with the country's Antimonopoly Act and has suggested that contracts should not contain resale restrictions. The growing volumes of US LNG, which are generally flexible and free from destination restrictions can be a valuable bargaining chip in a buyer's market when consumers (re-)negotiate with their suppliers. Destination flexibility seems to be on this rise: gas from the Cameroon Floating LNG (FLNG) and Mozambique's Coral FLNG projects reportedly sold on a free-on-board basis, and various Indian and Chinese buyers are also reported as having secured destination flexibility in recent contracts.

With buyers generally over-contracted and few new LNG projects moving to final investment decision, contracting activity has slowed down considerably. Only a few new long-term supply contracts are likely to be concluded in the near term as the LNG market works through its current overcapacity. However, from the early 2020s onwards, new LNG capacity is likely to be needed in the market, implying new contracts which would typically be concluded well before new capacity comes on stream. This comes as a number of legacy contracts – especially in Asia – expire. In the period to 2025 over 150 bcm of supply agreements expire (representing some 35% of the contracts in place in 2015). Some 80 bcm of the expiring contracts have Asia as a final destination.

How this new contracting cycle evolves in Asia will be an important pointer for the long-term evolution of the LNG market. The views of Japan's Free Trade Commission on destination clauses and the availability of flexible LNG from the United States, are together likely to lead to a significant shift away from such clauses in future LNG contracts, promoting spot sales and liquidity in the LNG trade, and the pressure for change will only strengthen if anti-trust regulators in other importing countries, for instance Korea, take the same view as those in Japan.

The outlook for long-term contracts in Asia is more difficult to assess. On the one hand, some major LNG importers – for instance Japan and China – are moving ahead with electricity sector reform and this could make gas demand less predictable for their utilities (as their plants will increasingly be dispatched according to their rank in the merit order), especially when account is also taken of rapid increases in the deployment of variable renewables. On the other hand, much of the growth in demand for LNG comes from developing countries that are seeing rapid electricity demand growth within regulated power systems. With good visibility of future gas needs, they may feel more comfortable with long-term contracts, especially since it will take time for a liquid forward/futures market to become established.

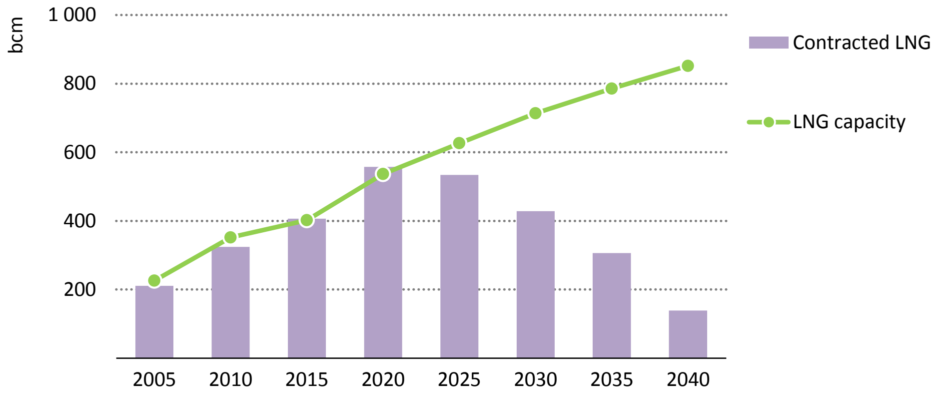
We may thus be entering a "hybrid period" in which various forms of supply arrangements – long-term and short-term, large and small, oil-indexed, hub-based and spot – coexist and compete with each other, reflecting the different needs of buyers and sellers alike. In the long-term, though, the direction of travel appears clear: a marked shift towards spot trade, contracts covering smaller volumes and shorter durations, and a distinct move away from destination clauses and oil-price indexation.

9.3.3 Investments and security of supply

The international market is currently awash with gas and projected import growth does not absorb the supply overhang in full until the mid-2020s. But new LNG projects are likely to need to be approved well before this point is reached if the market is to function smoothly in future, since lead times for such facilities can range between three and six years. In the New Policies Scenario, some 580 bcm of new liquefaction capacity is built over the *Outlook* period (corresponding to around 80 LNG trains) and 40% of this comes on stream over the 2020s. In total, cumulative investments of $8.6 trillion are needed for gas supply over the next 25 years. Most of the plants that are currently under construction and scheduled to come online through the early 2020s have secured long-term offtake arrangements for most of their output (Figure 9.13). However, the next wave of projects – anticipated to come online from the mid-2020s – has not (yet) concluded contracts and their investors need to cope with a market environment that is in flux.

Many companies undertaking major projects claim that oil-price indexation, long-term contracts and elements like take-or-pay and destination clauses are essential to provide the certainty needed to approve a capital-intensive LNG (or pipeline) project. Oil supply projects – which are no less capital intensive – do not however require any of the elements that LNG investors call for, because they are selling into a liquid and transparent market with a well-established pricing mechanism. A key question is thus whether investors and financiers have sufficient confidence in the emergence of a new gas market order to move ahead with projects. The speed at which the market (including the forward market) becomes deeper and more liquid is crucial; so too the speed at which reliable and transparent price indices are developed that can be used for spot and long-term contracts. There is also room for innovation on the financing side to find alternative ways to manage the risks associated with long-term capital-intensive projects. In our view, during the next investment wave, in the 2020s, prospective projects are unlikely to find a long queue of highly creditworthy offtakers prepared to make long-term procurement commitments. Contracts are set to remain an important element of risk mitigation in LNG project financing, but investors and lenders are likely to have to accept a larger exposure to spot market risks and opportunities, which will become easier to manage as relevant markets develop.

Figure 9.13 ▷ Already contracted versus projected global LNG capacity in the New Policies Scenario



From the early 2020s onwards, new contracts may be needed to underpin investment decisions for the construction of additional liquefaction capacities

Investment in a market that is undergoing transition has a number of implications for financing. Fewer guaranteed future cash-flows (from long term contracts with take-or-pay clauses) reduce the ability to finance a project with a high share of debt, potentially requiring the investor to provide more equity. But fewer guaranteed cash-flows also requires investors to be attentive to future risks of demand, including those related to policies addressing climate change (Chapter 11). In any event, cost control is paramount – lenders are likely to be willing to provide financing even if the project is not fully covered with contracts, but only if the economics are compelling (see next section). The focus may shift to brownfield and smaller, modular projects (including floating LNG plants) as their lower capital costs and shorter payback period allows investors to accept shorter contract durations.

In addition, some smaller LNG exporters may be good at their core activity – producing and liquefying gas – but have less experience in managing risk and commercialising gas. This provides a business opportunity for companies that specialise in handling market risk, including risks related to incomplete contract coverage of new projects, which may involve providing the link between exporters and smaller, less creditworthy buyers in developing countries. Aggregators and trading houses have started to act as intermediaries and mitigate the risk of both producers and consumers by contracting significant amounts of LNG capacity and marketing the gas globally (Box 9.3). In terms of volume, around half of the contracts concluded between 2010 and 2016 are held by aggregators. The changing market environment provides plenty of scope for commercial innovation and a greater role for such players in the global LNG trade. Another way of hedging price and volume risk is vertical integration i.e. upstream producers investing into downstream assets, and consumers acquiring stakes in production and export facilities (for instance, Gazprom has been pursuing plans to acquire or build gas-fired power plants in Europe and China; US gas producers have entered joint ventures with logistics companies to roll out refuelling infrastructure for LNG trucks; and Chinese gas importing companies and European utilities are active in upstream and midstream development).

Box 9.3 ▷ The role of aggregators in LNG trading

Aggregators have been a key force in underpinning the growth in LNG supplies over the last decade. They have supported the development of new LNG projects by committing to significant volumes in emerging LNG supply regions such as Australia and the United States. Aggregators, also called portfolio players, are typically international oil and gas companies or large utilities with global operations that, in addition to having their own equity LNG production, have enhanced their supply portfolios by signing up to long-term deliveries from other LNG projects. These supply portfolios can in turn be used to provide LNG to a range of existing and new customers. The portfolio business model started to develop in the mid-2000s, as BG Group expanded its LNG trading and marketing activities. Since then, a variety of companies such as Shell, Total, BP, Engie, and Gas Natural Fenosa have emerged as portfolio players. Aggregators are attractive to LNG producers because of their typically large balance sheets and strong creditworthiness. They are also attractive to buyers, due to their portfolio of different supply sources and the scope this provides for contract flexibility in terms of length and volume. A well-supplied market in the coming years could put the business model under pressure, as aggregators are taking on significant volume and price risks, but our projections suggest the possibility to grow a sustainable and profitable LNG portfolio over the longer term as market conditions tighten. A revival of aggregator interest in signing up for new LNG contracts and underpinning new investment in supply would be an important indicator that a second LNG wave is on the horizon.

Increasing competition, more flexible trading arrangements and growing diversity of suppliers over the *Outlook* period would bring benefits for security of gas supply. LNG, which can easily be re-routed, reaches a share of 60% in inter-regional trade in 2040, up from less than 40% in 2016. Another measure of diversity is the number of liquefaction sites operating worldwide (each of which can contain multiple projects or trains) which has grown two-and-a-half-times since 2000, reaching nearly 40 in 2016. In the New Policies Scenario, the anticipated number of sites increases to around 80 by 2040. The expansion of LNG trade means that, at any given time, more LNG cargos are travelling the world's seas: today, some 290 LNG cargos are delivered per month on average, a number that increases to 660 in 2040 in our projections. The emergence of new market participants also increases the density of the LNG trade network (e.g. an expansion of China's LNG imports brings additional LNG tankers to a region that has a number of other large importers).

As the LNG market evolves, so it becomes better equipped to respond to sudden calls for additional imports, as might be required in the event of a disruption on a major import pipeline or a demand shock (of the sort witnessed in the aftermath of the Fukushima-Daiichi accident). Greater availability of shipments and greater flexibility of flows means that the time it would take to divert LNG tankers and bring the gas to a new destination drops significantly over the *Outlook* period. We estimate that, by 2040, major LNG importers would be able, on average, to increase their LNG deliveries by 10% in just over ten days, a week less than estimated for 2016 in the case of Japan and Korea, and the European Union (Figure 9.14). The drop is less pronounced for China, as the country's growing import needs offset some of the positive effects from greater flexibility of the LNG trade.

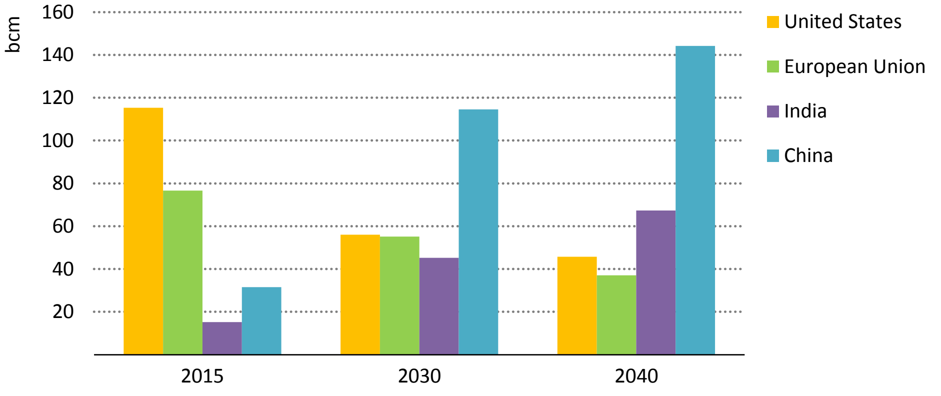
9

Figure 9.14 ▷ Estimated average time to procure an extra 10% of LNG import volumes by selected importer in the New Policies Scenario

As LNG trade expands and becomes more diversified, major LNG importers are able to meet an unforeseen 10%-spike in their LNG import demand in much less time than today

The benefits to gas security from the expansion in LNG supply are particularly significant as they can help to compensate for prospective losses of flexibility in other parts of the energy system, that might arise from the depletion of domestic gas fields in importing regions or the reduced possibilities, in some markets, to switch away from gas if prices rise. The power sector is typically an important provider of flexibility, as utilities often have the ability to switch to other fuels if gas becomes too costly, unlike most households or industrial consumers. In this regard, our projections highlight some countervailing trends. On the one hand, in the period to 2030, coal-fired power plant capacity decreases by nearly 40% in the European Union and by over 20% in the United States (oil-fired capacity also drops in both systems by more than 60% to 2030), reducing the fuel switching capability in these power systems markedly (Figure 9.15). On the other hand, over the same period, gas makes inroads to various coal-heavy power systems, e.g. in Southeast Asia, India and China, increasing the flexibility there.

Figure 9.15 ▷ Annualised potential to reduce demand for gas by switching to coal in selected power systems



The ability to temporarily switch away from gas decreases in the US and the European Union as coal plants are closed, but increases in China as more gas plants are built

Whether the increased price elasticity in developing countries can offset the reduced price responsiveness in various advanced economies hinges on the effectiveness of energy market reform in these countries in the first-half of the *Outlook* period. A well-functioning internal gas market (with third-party access to regasification terminals and pipeline infrastructure, ownership unbundling, transparency and unified network codes etc.) is a prerequisite for the efficient allocation of gas during periods of scarcity or high prices and the identification of consumers that are willing to cut back on their gas use. Electricity market liberalisation also contributes to flexibility because it underpins plant dispatch according to marginal generation cost, triggering a fuel switch if needed. Various countries are undertaking reform of their gas and electricity markets over the coming years – prominent examples are China (see Chapter 14), Japan and various countries in Southeast Asia – and successful implementation would contribute to the ability of the demand side to react to supply shocks (Box 9.4).

Box 9.4 ▷ How can Asian consumers benefit from the changes in gas markets?

For decades the "Asian premium" has been a key feature of global gas markets. To a degree, such a premium – the notion that gas is systematically more expensive in East Asia than in Europe or North America – can be justified by geography. Theoretically, in a well-functioning gas market, in which US exporters are the marginal suppliers, arbitrage opportunities would keep prices in Japan no more than $2/MBtu above the price level in Europe (representing the difference in shipping cost between Europe and Japan). However, for long periods the Asian price remained above the level justifiable by marginal supply costs, because of a lack of competition in the market; this premium price level has contributed to coal's competitive edge in many Asian power systems. The transformation of LNG markets creates a huge opportunity for gas users in Asia.

Even with a more efficient and competitive LNG market and lower wholesale prices, there is no automatic guarantee that changes will trickle down to the final consumers of the gas. If domestic markets remain monopolised, with physical and regulatory barriers preventing market entry and keeping end-users away from international LNG markets, the LNG market transformation will simply transfer rents from the LNG producers to the incumbent utilities of Asia. Some of these utilities have a high exposure to expensive long-term contracts and this may limit their immediate interest in the emergence of an efficient competitive domestic market.

Having sufficient infrastructure available for third-party use is the basis of an efficient gas market. Most global gas infrastructure was originally developed by integrated monopolies, but regions where gas markets are efficient today have implemented unbundling measures, forcing the separation of infrastructure from commercial activities and ensuring its non-discriminatory operation. Experience has shown that ownership unbundling, which leads to the creation of completely independent infrastructure entities, can – in sufficiently mature gas markets – lead to transformative results. Experience in Europe and the United States has also shown that there are very strong synergies between efficient gas and electricity markets, indicating that there is much to be said for an integrated approach to structural energy sector reforms.

Most Asian importers lack a dense domestic pipeline network, as LNG terminals have been developed one by one to serve the main consumption hubs. While geography limits interconnectivity between countries, especially in Japan and Southeast Asia, there is considerable scope within countries for better linkages between demand centres and multiple LNG terminals. Third party access can attract new infrastructure investment – for example in pipelines and regasification terminals – if regulators ensure cost recovery and prevent conflicts of interest. Due to geology, underground storage is unlikely to play a similar role in some parts of Asia as it does in Europe and North America. Where there is little gas storage, access to LNG becomes even more important as a way of providing flexibility. Exchange of information and the sharing of experiences between gas traders in Asia and those in other parts of the world is another potential way to enhance market efficiency (a recent memorandum of understanding between Japan and the European Union points in this direction).

Investors in gas supply typically try to avoid under-utilised liquefaction facilities and pipelines, although this can bring benefits to the system as a whole by cushioning price volatility and reducing the amplitude of cycles. However, there is occasionally some slack in the system and this can increase its resilience. At present, for instance, Russia has ample spare production capacity and is well connected to the European market. In a period of gas scarcity, Russia could increase its shipments to Europe in order to free up some LNG that could then be re-directed elsewhere (although this could lead to uneasiness about the high exposure to Russian gas in some European countries). This would however be a possibility only if there is LNG available which is not tied to a specific location through a destination clause (or through another restriction that hinders easy re-routing of LNG such as a delivery ex-ship clause).

From a slightly longer-term perspective, another important element for security of supply is the availability of cheaper and more scalable LNG projects that make it possible for market participants to respond more quickly to price peaks. Technological innovations like FLNG may have a useful role to play in this respect. In the United States, a well-established construction and engineering industry and a large number of existing facilities provide ideal conditions for US exporters to rapidly bring new brownfield projects on stream if market signals justify this. Qatar is another country with the capacity for relatively low-cost and rapid expansion of liquefaction capacity in such circumstances, now that it has lifted its self-imposed development moratorium.

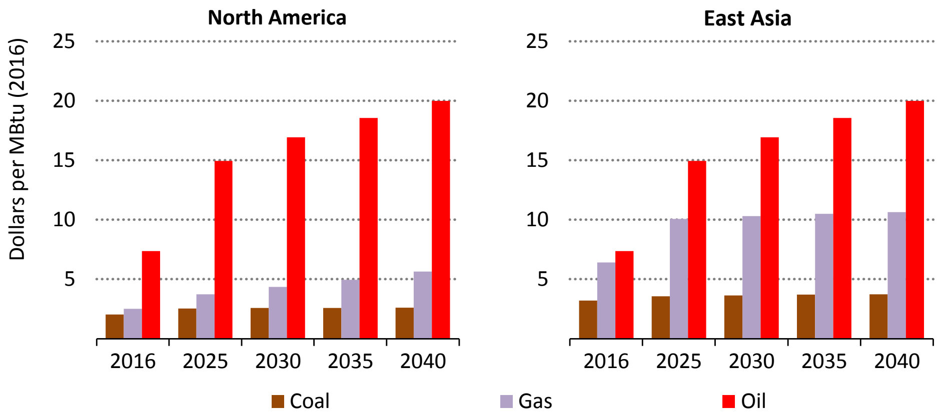
9.3.4 Affordability of gas

Gas prices are currently at low levels around the world. The International Gas Union estimates the average global price of gas at $3.35/MBtu in 2016, the lowest level ever recorded in their surveys (IGU, 2017). On average in 2016, prices in the European Union and Japan were some 60% below the peak reached in 2012. These low prices have led many gas consumers to hope that high gas prices are gone for good. However, the current low gas prices are a signal of oversupply, and there is a risk that prices at this level may not trigger sufficient investment activity. In the long term, only gas prices that cover the full cost of gas supply and provide sufficient incentive to invest into new projects are sustainable, implying a rise in gas prices around the world.

The lower energy density of gas, compared to oil or coal, means that transportation takes a relatively high share of the delivered cost, making geographical proximity to resource-rich areas an important determining factor for affordability. Gas transportation infrastructure is very capital-intensive, and moving gas also means using or, occasionally, losing volumes along the way (for instance, boil-off on LNG vessels, own-use in liquefaction plants and compressor stations, or leakage in pipelines). The cost of transporting gas over long distances is, for the same energy content, between seven- and ten-times more expensive than oil or coal, which is why gas prices in different regions would continue to vary substantially even in a globalised gas market. For new investment projects, the longer the distance over which gas has to be transported, the more favourable the economics of LNG are likely to be over pipelines.

How the economics work for gas depends also on how the fuel is used and what alternatives are available. This can vary widely across different parts of the energy sector and will also vary over time with the falling cost of key renewable technologies (see Chapter 11). In industry, for example, gas has a clear competitive advantage where it displaces more costly oil products (Figure 9.16). Light industries (e.g. manufacturing, textiles, food and beverages) that rely on coal may also be willing to switch to gas, even if it is more costly, simply because gas is more convenient and cleaner. The competition to gas in the buildings sector, by contrast, comes from electricity, the direct application of renewables, e.g. from heat pumps, and from energy efficiency. In the transport sector, natural gas can provide an alternative to oil products for freight and maritime uses, but electricity is emerging as the preferred way to move away from oil for passenger vehicles.

Figure 9.16 ▷ Fuel price evolution in North America and East Asia in the New Policies Scenario



Gas has a clear cost advantage over oil, but beating coal on commercial terms in gas-importing regions is a difficult task

The power sector, which accounts for 30% of the growth in global gas use over the *Outlook* period, is a different case again. In Asia, the target region for the bulk of the LNG exporters, coal is hard to beat on straight commercial terms in baseload power generation, confining gas plants to the provision of mid-merit and peak load power, except where they are given preference because of environmental considerations. Gas also has to compete for market share with renewables, which are growing fast and enjoy significant policy support and falling costs: while it is true that providing flexibility for the integration of wind and solar PV is an important opportunity for gas-fired power plants, the volumes of gas consumed for this task are considerably smaller.

Increased competition on the supply side, a critical component of the new gas order described in this chapter, can help to make gas more affordable in the long term. Compared with the steam coal market, which is characterised by a high degree of competition and low rents, in the gas market some large exporters have managed to command prices that far exceed their full costs (in part by limiting the speed at which they develop new resources). The entry of new suppliers into the LNG market and the rise in exports from the United States, a country where resource rents are traditionally low, is set to limit the scope to extract additional revenue in this way.

A more competitive environment creates pressures all along the supply chain. Cost discipline becomes paramount for new projects to move ahead. The technology improvements that unlocked shale gas as a low-cost resource in the United States have been instrumental in the transformation of global gas markets, and this could yet have an impact in other countries with promising unconventional resources. However, it appears less likely that a similar step-change in costs is on the horizon for gas transportation, where the main cost elements are steel, cement, specialised equipment for refrigeration and liquefaction (for LNG) and construction services. For new pipelines and LNG facilities, the gains are more likely to be incremental, via careful choice and design of projects and greater use of modular and/or standardised approaches to construction. The main area of innovation is likely to be greater deployment of floating technologies, both for liquefaction and regasification (see Box 8.2 in Chapter 8).

Governments in resource-rich countries may also feel pressure to change the design of production sharing agreements or fiscal instruments like specific taxes, royalties and export duties. Without such changes, marginal projects may struggle to move ahead in a more competitive environment, especially given the recent decision from Qatar, one of the world's lowest-cost suppliers, to expand its LNG capacity. New gas-supply projects already receive favourable treatment in some jurisdictions: Russia, for example, levies a 30% export tax on traditional pipeline gas exports in addition to upstream taxes, but LNG projects such as Novatek's Yamal LNG are exempt.

There is also a chance that future gas markets may be less prone to volatility than in the past. The new gas order is set to be more sensitive to shifts in regional prices (that, in turn, are increasingly likely to be driven by the dynamics of gas-to-gas competition), and a diverse range of LNG suppliers can be expected to seek out opportunities for arbitrage rather than trading point-to-point with a fixed group of customers. Gas consumers may also be willing to accept a slight premium for gas if that enables investment in additional sources of flexibility, such as spare liquefaction capacity or storage, that assures them of price stability.

9.3.5 What underpins our New Policies Scenario?

Our gas production and inter-regional gas trade projections to 2040 assume various changes in the way the gas market functions, many of which are driven by the growing importance of LNG. This evolution of the gas market broadly follows three phases:

- The period to the early-2020s is characterised by continued oversupply, low prices and subdued investment activity as LNG export projects that are currently under construction, mostly in the United States, Australia and Russia, come on stream.

- The years between the early and the late 2020s see a wave of new gas supply projects going ahead as demand increases, fostering a smooth rebalancing amidst a rapidly changing and uncertain market environment.
- The latter part of our projection period witnesses the emergence of a truly global, liquid and competitive gas market in which the interplay of supply and demand determines a set of prices that suppliers and buyers both trust sufficiently to use as the basis for their future plans.

Our modelling of gas demand and supply trends requires us to make a number of assumptions and judgement calls in each of these phases. The second phase, which is at the heart of the transition towards the new gas market order, is also at the heart of the uncertainty. The emergence of this new gas order is particularly sensitive to two premises. First, we assume that diverging oil and gas price trajectories in the New Policies Scenario provide a strong impetus for change, making gas which is priced off a hub more attractive than oil-linked gas supplies and hastening the removal of oil-indexation in Asia and elsewhere. A sustained period of cheap oil could delay this evolution substantially (see Spotlight on the Low Oil Price Case in Chapter 4). Second, we assume that the removal of contractual rigidities, the gradual move towards gas-to-gas pricing (including the establishment of a liquid Asian hub), the rise in spot and short term trading and the strengthening of competition – all major elements of this phase – do not impede investors' and lenders' confidence in the commercial viability of new gas projects. Instead, they create a benign gas market environment with a level of trust in the market that underpins a growing reliance on gas imports around the world. However, quite the contrary could also happen: investors and financiers could prefer to take a 'wait-and-see' approach, preparing the ground for another major boom-and-bust cycle.

This second assumption is a particularly crucial one. Failure to bring on timely new investment implies (temporary) tightness and price volatility, which could jeopardise the perception of gas as a reliable and affordable source of energy in key gas-importing countries. Some well-established gas consumers could revert to securing their supplies through restrictive long-term agreements, slowing the pace of structural change in the gas market order. Moreover policy-makers in importing countries could lose trust in gas, delay gas infrastructure development, and ease the pursuit of policies that foster gas use to achieve environmental objectives. These responses could in turn mean a reduction in the 1.6% of annual growth in gas demand in the New Policies Scenario, as countries move to coal or renewables (or a combination of the two). The bright future we outline for gas in the New Policies Scenario cannot therefore be taken for granted – it requires the concerted efforts of policy-makers and industry leaders to navigate the stormy seas of transition in order to position gas as a reliable and affordable fuel.

The environmental case for natural gas

How do methane emissions tip the balance?

Highlights

- As the cleanest burning fossil fuel which emits few local air pollutants, natural gas has many advantages in a world concerned about carbon emissions and air quality. However, methane emissions along the natural gas value chain, if they are not abated, threaten to reduce the climate benefits of using natural gas.
- Oil and gas operations are not the only anthropogenic source of methane emissions, but they are likely the largest source from the energy sector. We estimate that global oil- and gas-related methane emissions in 2015 were 76 Mt, more than half of which stemmed from natural gas operations. Eurasia and the Middle East are the highest emitting regions, accounting for nearly half of the total emissions globally, followed by North America. The uncertainty in oil and gas methane emissions levels is high, but enough is known to conclude that these emissions cannot be ignored and that they represent a clear risk to the environmental credentials of natural gas.
- Our estimate of methane emissions from natural gas operations corresponds to an emission intensity of 1.7%. On average natural gas generates significantly fewer greenhouse-gas emissions on a lifecycle basis than coal. Yet, that is no reason for failing to take action to reduce methane emissions from natural gas operations. By developing first-of-a-kind marginal abatement cost curves, we estimate that it is technically possible to reduce global methane emissions from oil and gas operations by roughly 75%, and that emissions could be reduced by 40-50% just by implementing approaches that have no net costs, as the value of the captured methane is higher than the cost of the abatement measure.
- There is an increasing number of voluntary and regulatory efforts to tackle methane emissions from the oil and gas sector. Worldwide implementation of the abatement measures that have positive net present values in the New Policies Scenario would require a step-change in ambition, and few countries outside North America have specific mitigation frameworks in place. But this would have the same impact on reducing the average global surface temperature rise in 2100 as shutting all the coal-fired power plants in China today. Methane emissions reduction policies are also critical in the Sustainable Development Scenario, despite the lower levels of fossil-fuel consumption.
- We have developed an action agenda for policy-makers and industry, based on the need to accomplish two key goals: measure and abate. Measurement is critical to assess the efficacy of policy actions and to assure the public of effective implementation. Abatement is critical to reduce emission levels.

10.1 The environmental credentials of natural gas

The case for gas to play an expanded role in the future of global energy is inextricably linked to its credentials as a solution to environmental problems. In a world in which concerns about air quality and climate change loom large, but in which there are limits to how quickly renewable energy options can be scaled up and some sectors in which low-carbon energy options are hard to find, natural gas offers many potential benefits. Gas combustion emits fewer carbon-dioxide (CO_2) emissions per unit of energy output than coal or oil, plus fewer local air pollutants than coal, oil or bioenergy. The use of natural gas is also often more efficient than coal in numerous transformation and end-use sectors. Gas-fired power plants are well-suited to the demand for flexible operation that comes with a rising share of variable renewables in the power mix. But, on the other side of the ledger, gas does have drawbacks; it still results in CO_2 emissions when combusted and, most significantly, it is itself a potent greenhouse gas if emitted directly to the atmosphere.

There is very little dispute over the emissions associated with natural gas combustion, but there is less consensus over the level of direct methane emissions that occur during its production, transportation and consumption. This is an issue for natural gas, as uncertainty over the level of emissions raises questions about the extent of its real environmental benefits. This chapter aims to identify the sources of this uncertainty and explore what actions can be taken to reduce both uncertainty and emissions. After an initial review of the environmental case for and against natural gas, the chapter focuses in detail on the issue of methane emissions.

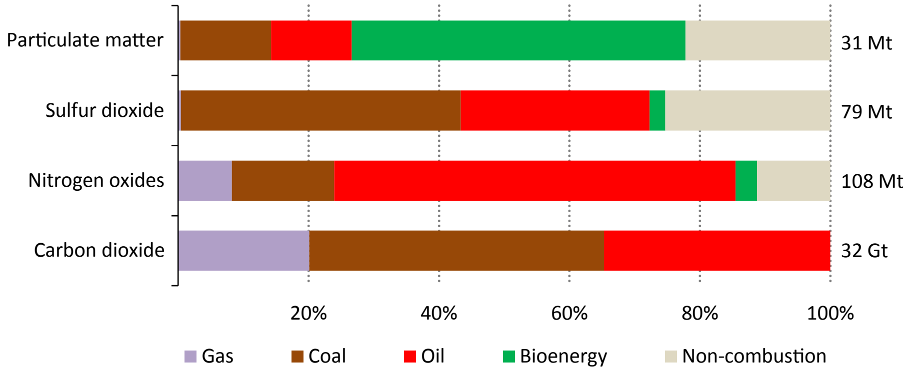
The first task is to understand the nature and volume of methane emissions worldwide, and the extent to which they come from the energy sector – and, within this sector, from oil and gas – in each case assessing the key gaps in today's knowledge and data. The section of the chapter dealing with these issues concludes with a discussion of what different assumed methane emissions levels from the gas supply chain would mean for the relative climate benefits of gas versus coal. The chapter then describes what is being done by countries around the world to address the issue, and the economic and climate costs and benefits of further action. The concluding section provides guidance for policy-makers and others looking to step up their commitment to methane abatement.

10.1.1 Assessing the environmental credentials of natural gas

The emissions that arise from the combustion of natural gas are well-known and show clear advantages for gas relative to other fossil fuels and, for particulate emissions, a favourable comparison with bioenergy. In relation to CO_2, the combustion of natural gas results in emissions savings of some 40% relative to coal for each unit of energy output. The advantage over oil is less striking, but still substantial: CO_2 emissions from gas combustion are around 20% lower than for oil. Quantifying the CO_2 savings from natural gas use is a complex business (discussed in more detail in Chapter 11) but it is undeniable that gas has played an important part in recent positive CO_2 emissions trends in many countries and in the overall flattening of global energy-related emissions since 2014.

The edge of natural gas over the other combustible fuels is reinforced by looking at the emissions of the main air pollutants: fine particulate matter ($PM_{2.5}$), sulfur oxides, mainly sulfur dioxide (SO_2), and nitrogen oxides (NO_X). These three pollutants are responsible for the most widespread impacts of air pollution, either directly or once transformed into other pollutants via chemical reactions in the atmosphere. Controlled burning of natural gas releases very few particulate emissions into the air. In global terms, the combustion of wood and other solid fuels are responsible for more than half of current $PM_{2.5}$ emissions, mainly in developing Asia and sub-Saharan Africa where bioenergy is still widely used as a cooking fuel (Figure 10.1).

Figure 10.1 ▷ Share of natural gas in total energy-related emissions of selected air pollutants and CO_2, 2015



Compared with other sources, natural gas makes only a minor contribution towards today's emissions

Notes: Mt = million tonnes; Gt = gigatonnes. Non-combustion emissions are process emissions in industry and non-exhaust emissions in transport.

The relationship between fuel use and pollutant emissions is not straightforward as it depends on fuel grades and qualities, the nature of the combustion process and whether or not post-combustion control technologies are applied. But differences in emission levels across the fossil fuels emerge very clearly from the data. Coal use dominates global emissions of SO_2 – a cause of respiratory illness and a precursor of acid rain – followed by emissions from oil. Although most fossil fuels contain sulfur when extracted, this is removed as soon as practicable after production from the natural gas stream, both for safety reasons and to avoid corrosion to pipelines; for these reasons, SO_2 emissions from the use of natural gas are negligible. In addition, unlike emissions from the combustion of coal, natural gas does not emit any mercury or other heavy metals. Combustion of natural gas does produce NO_X, which can trigger respiratory problems and the formation of other hazardous particles and pollutants. However, gas accounts for less than 10% of global energy-related NO_X emissions. The majority of NO_X emissions are attributable to oil products (especially diesel) used in the transport sector: a lot of car and truck exhaust fumes are emitted in urban environments at street level, which has a major impact on urban air quality and public health.

These generally low-emission characteristics of natural gas help to underpin its status as a relatively clean fuel compared to other fossil fuels. But that does not necessarily give natural gas a clean bill of health. There are three main arguments regularly made against natural gas (including both conventional and unconventional gas)[1] questioning its suitability as a long-term answer to the world's energy and environmental challenges. The first is that, while preferable to coal, it is still a significant and growing source of CO_2 emissions and so cannot be exempt from efforts to tackle climate change (discussed in detail in Chapter 11). The second is that methane emissions along the gas value chain are potentially at a scale that they could negate some of the climate advantages claimed by gas when combusted; this is the key question addressed in this chapter. The third is that the process of extracting natural gas is associated with an unacceptable level of social and environmental risk.

Box 10.1 ▷ Public acceptance of unconventional gas: the "Golden Rules"

- Measure, disclose and engage, involving meaningful and timely engagement with local communities, establishing key environmental baselines before drilling and disclosure of key operational data, including on hydraulic fracturing.
- Watch where you drill, taking into account established settlement patterns and local ecology, plus key geological and hydrological factors, such as the presence of faults or water supplies and sources.
- Isolate wells and prevent leaks, through ensuring well integrity and preventing and containing surface spills.
- Treat water responsibly, by reducing freshwater use, and paying close attention to treatment, storage and disposal of waste water.
- Minimise air emissions by reducing flaring, eliminating venting and paying careful attention to other emissions.
- Consider the cumulative and regional effects of large-scale drilling and production operations, especially for water, but also for truck traffic, noise and other local disruptions.
- Ensure consistently high, ongoing environmental performance, with properly resourced regulators, encouraging performance-based and full cradle-to-grave regulation.

On the last point, the *World Energy Outlook (WEO)* has argued consistently that gas will only flourish in the global energy mix if important social and environmental concerns regarding

1. Unconventional gas includes coalbed methane, shale gas and tight gas. Just over 20% of global gas production is currently unconventional, a share that rises to just over 30% in the New Policies Scenario in 2040.

its extraction are addressed. In relation to unconventional gas, these issues were addressed in detail in a *WEO* special report, *Golden Rules for a Golden Age of Gas* (IEA, 2012), which set out seven overarching principles, or "Golden Rules", designed to provide guidance to policy-makers, regulators and industry in developing balanced, effective regulatory regimes for unconventional gas (Box 10.1).

Application of these principles can ensure a level of environmental performance that earns a "social licence to operate" for industry, paving the way for large-scale gas development. The alternative is to run the risk of social and political backlash. The challenge in ensuring public acceptance is well illustrated by the patchwork of different policy approaches governing unconventional gas development in different parts of the world, and within individual countries. This includes moratoria on hydraulic fracturing in many parts of Europe as well as in certain states or provinces in the United States, Canada and Australia.

10.2 Methane emissions: how big is the problem?

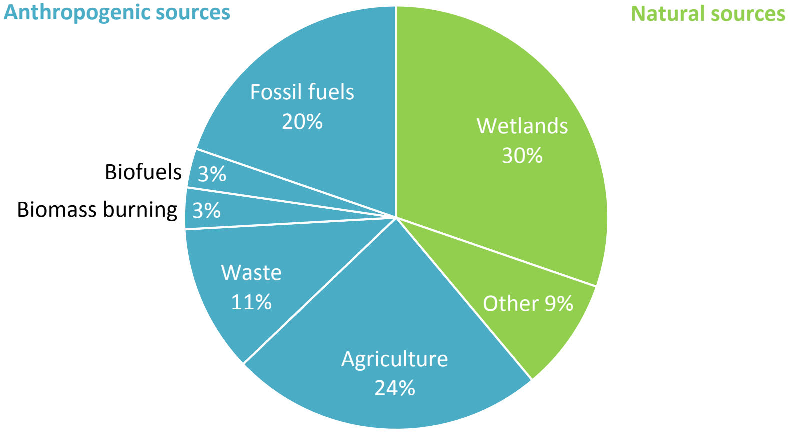
The concentration of methane in the atmosphere is currently around two-and-half times greater than pre-industrial levels (EPA, 2016). Like CO_2, methane (CH_4) is a potent greenhouse gas and this rise has important implications for climate change. Unlike CO_2, however, methane only exists in the atmosphere for around 12 years (Myhre et al., 2013), which complicates the calculation of its impact on global warming (Box 10.2). It is estimated that in 2012, the latest date for which comprehensive data are available, global methane emissions from all sources were around 570 million tonnes (Mt). This includes emissions from natural sources, which account for about 40% of annual emissions, such as wetlands, fresh water, geological seepage, melting permafrost[2] and oceanic sources, and from anthropogenic sources, which account for about 60%, such as agriculture, waste and the energy sector (Figure 10.2). The largest source of anthropogenic methane emissions is agriculture, responsible for around 140 Mt of emissions in 2012, closely followed by the energy sector (including emissions from coal, oil, natural gas and biofuels). Global methane emissions are estimated to have risen by around 5% since the first-half of the 2000s, most likely as a result of increases in emissions from agriculture (Schwietzke et al., 2016; Nisbet et al., 2016).

Estimates of methane emissions are subject to a high degree of uncertainty. There are two key methods for estimating emissions levels: "top-down" and "bottom-up". Top-down methods first measure the atmospheric concentration of methane (whether at global, regional or facility level) using remote measurement devices such as permanent ground or tower-based measuring stations, or dedicated aircraft, vehicles or satellites. Changes in the atmospheric concentration of methane over time are then "inverted" to estimate what annual emissions must have been to yield these changes. The uncertainty in this calculation of total emissions arises from the fact that methane concentrations are measured at an elevation or at a distance from the emissions source; this complicates the

2. Permafrost is frozen soil, rock or sediment, usually found in high latitudes or beneath the seabed in polar regions. It can contain large quantities of CO_2 and CH_4, which can seep out if the ground melts.

attribution of emissions to specific sources, due to dispersion in the atmosphere (despite the use of atmospheric flux models that account for variables such as wind speed). Some studies distinguish between emissions from fossil fuels and from other sources based on the specific methane isotopes detected (Schwietzke et al., 2016), but in general assigning emissions to precise sources using a top-down method is very difficult.

Figure 10.2 ▷ Sources of methane emissions, 2012



Attributing methane emissions to specific sources is difficult, but human activity is likely to be responsible for the majority of the 570 Mt emissions in 2012

Source: Saunois et al. (2016).

The alternative bottom-up approach tackles the issue from the opposite angle. Measurements are taken directly at the source (such as a leaky piece of equipment) and so are more accurate in terms of location of the source and the volume of methane emitted. But the key shortcoming is that certain sources may not be detected. In the oil and gas sector, for example, there is a huge number of potential sources of emissions worldwide: each oil and gas installation consists of thousands of individual pieces of equipment that could be continuous or sporadic sources of fugitive emissions. It is impractical and cost-prohibitive with current technologies to measure, and monitor in real time, emissions from all potential sources on a continuous basis using a bottom-up method.

There have been recent attempts to combine the top-down and bottom-up approaches: using atmospheric measurements to constrain the annual level of emissions in a certain region and using a bottom-up method to apportion this between different sources (Zavala-Araiza et al., 2015a). These methods hold promise, and will be aided by improving bottom-up estimates and new approaches to measuring atmospheric concentrations at higher resolutions. Identifying practical actions that can be taken to reduce further the current uncertainties will be very important: so will reducing methane emissions levels despite the uncertainties that exist.

Box 10.2 ▷ The pitfalls of global warming potentials (GWP)

Two key characteristics determine the impact of different greenhouse gases on global warming: the ability of a gas to absorb energy and the length of time it remains in the atmosphere. There are various ways to combine these factors to estimate the effect on global warming; the most common is the global warming potential (GWP), which is the ratio of the energy absorbed by a tonne of a greenhouse gas to the energy absorbed by a tonne of CO_2 over a given timeframe. This measure is used to express a tonne of a greenhouse-gas emitted in CO_2 equivalent terms, in order to provide a single measure of total greenhouse-gas emissions (in CO_2-eq). Methane has a much shorter atmospheric lifetime than CO_2 (around 12 years compared with centuries for CO_2), but absorbs much more energy while it exists in the atmosphere. The Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) indicated a GWP for methane between 84-87 when considering its impact over a 20-year timeframe (GWP_{20}) and between 28-36 when considering its impact over a 100-year timeframe (GWP_{100}) (Myhre et al., 2013).[3] Alternative metrics have been suggested, such as the global temperature potential (GTP), the ratio of the temperature increase after a specific number of years resulting from a tonne of a greenhouse gas relative to that of CO_2, but these too vary markedly depending on the timeframe considered.

There are a number of difficulties associated with the use of GWPs despite their prevalence in national greenhouse-gas emissions accounting frameworks and climate policy discussions. The use of a single GWP implies a constant impact from emitting a tonne of CH_4 when the actual impact varies significantly over time. GWP_{100} and GWP_{20} values have also been updated in successive IPCC reports as scientific knowledge advances. This has led to confusion given the trade-off between using the most recent value and using a more dated value but maintaining consistency. As well, and perhaps most importantly, the choice of GWP_{100} or GWP_{20} has a major impact on the apparent potency of CH_4, and so the importance placed on the level and timing of emissions mitigation as well as any assessment of the relative emissions reduction benefits of gas vis-à-vis coal or oil. The choice of the most appropriate timeframe depends on the emissions scenario in question, for example if or when there is a peak in the global temperature rise, and can be relatively subjective.

Here we avoid any reliance on GWP (or GTP) in assessing the importance of reducing CH_4 emissions from oil and gas operations. All quantities of methane are presented in million tonnes of CH_4 and are not converted into CO_2-eq. Instead we use the climate model MAGICC[4] (Meinshausen et al., 2011), widely employed in studies assessed in the IPCC reports, to estimate the impact of different CH_4 emissions pathways on the

3. The ranges for the GWP over a certain timeframe arise from whether the methane comes from a fossil or biospheric source and whether or not potential climate-carbon feedbacks are included. These feedbacks are processes that lead to a change in the carbon cycle, such as a decrease in the level of CO_2 emissions absorbed by forests instigated by the temperature change from the methane emitted.

4. MAGICC = Model for the Assessment of Greenhouse Gas Induced Climate Change.

average global surface temperature rise in 2100 (in degrees Celsius [°C]). Since the temperature rise has a near-linear relationship with cumulative CO_2 emissions, we compare the temperature differences in 2100 under these CH_4 emissions pathways with the cumulative quantities of CO_2 that would yield similar temperature differences.

10.2.1 Methane emissions from the energy sector

Methane emissions from the energy sector in 2012 are estimated at between 100 Mt and 200 Mt.[5] This includes emissions from the extraction of oil, natural gas and coal, natural gas transport and consumption by end-users, and the consumption of bioenergy.

Coal seams contain methane, referred to as coal mine methane (CMM), which can be released during the coal mining process. As the world's biggest producer and consumer of coal, China is by far the largest emitter of CMM. China's National Development and Reform Commission estimated that coal-related methane emissions in 2005 in China amounted to 15 Mt, but there is large measure of uncertainty about this, with sources suggesting emissions in 2005 could have ranged anywhere from 5 Mt to 35 Mt (Ju et al., 2016). Chinese coal production has increased by around 50% since 2005, and so current CMM emissions are likely much higher. Globally, it is estimated that CMM emissions in 2012 could range between 30 Mt and 60 Mt (Saunois et al., 2016). Methane can be released in various ways during coal mining, including from the degasification and ventilation systems in underground coal mines (necessary to avoid explosions); exposed coal seams in surface (or open pit) mines; abandoned mines; and post-mining activities such as storage and transport. The concentration of methane in the emitted air varies significantly by source. Wells drilled to degasify mines produce methane in high concentrations while that in the air from ventilation systems is low (less than 1%) as the methane content in the mine shafts has to be diluted by circulating air in order to create safe working conditions. The concentration of methane in coal seams depends on the type of coal and the geological conditions at the time of formation and subsequent burial of the coal seams.

The lower the concentration of methane, the more technically and economically difficult it is to abate. Around two-thirds of CMM in the United States comes from underground mine ventilation systems with a further 15% from surface mines (EPA, 2017a). This means that close to 80% of all CMM in the United States has a low methane concentration. Technologies do exist to burn low-concentration CMM as a primary or supplementary fuel in turbines and industrial boilers, but doing so economically can be challenging. The only option to recover CMM from surface mines is via pre-mining drainage, which is a lengthy process. Emissions from operational surface coal mines are diffuse and therefore difficult to capture and recover. As 65% of the world's coal comes from underground mines, capturing

5. This range is based on the lowest top-down estimate of Saunois et al. (2016) and the upper end of the estimates of Schwietzke et al. (2016). We also make allowance for the finding of Petrenko et al. (2017), which indicate that estimates of emissions from natural geological sources could be overestimated (and so emissions from oil, gas and coal production and consumption are underestimated) by at least 35 Mt.

CMM from the degasification systems of underground mines is probably the most effective solution: it can then be used in power generation either onsite or off-site. The methane concentration of gas from degasification wells can be up to 95% and thus sufficiently high to be sold directly. There is some technical potential to reduce methane emissions from coal mining and many efforts have aimed at just that: the Global Methane Initiative, for example, lists nearly 250 CMM abatement projects currently in progress around the world.

Methane emissions from biomass and biofuels occur during their production in some instances (for example, if produced using anaerobic digestion) and during their combustion when low oxygen availability results in an incomplete burn. The amount of methane emitted depends both on the material being burned and the burning conditions. A key source is the traditional use of biomass for cooking in developing countries. Directly mitigating these emissions is difficult, but moves towards more modern cookstoves that have a chimney or fan to aid combustion could help to lower emissions, as could the replacement of traditional biomass by stoves fuelled by liquefied petroleum gas, natural gas or solar (see Chapter 3). This chapter focuses on assessing and mitigating methane emissions from oil and gas operations rather than coal or bioenergy for a variety of reasons:

- Recent studies estimate that oil and gas operations combined are the largest source of methane emissions from the energy sector (Saunois et al., 2016; Schwietzke et al., 2016).
- Recent studies also indicate that the technical abatement potential (both in absolute and relative terms) for methane emissions from oil and gas is greater than that for coal or bioenergy (Höglund-Isaksson, 2012).
- Methane emissions captured during oil and gas production or transport can often be monetised directly and so emissions reductions could result in economic savings or be carried out at low cost (explored in more detail in section 10.4).
- The role of natural gas in the energy sector transition is of particular importance in the wider context of the special focus on natural gas in this year's *WEO*. In the Sustainable Development Scenario, coal consumption falls rapidly, lowering methane emissions from coal by default. In contrast, global natural gas consumption continues to grow for a period of time in the Sustainable Development Scenario (see Chapter 11).

10.2.2 Methane emissions from oil and gas operations

In examining methane emissions from oil and gas operations, it is important to define the scope of emissions and relevant terms (Box 10.3). Our analysis examines emissions sources along the full oil and natural gas value chains, except for any emissions that occur within industrial or residential buildings (on the basis that the abatement technologies and options for these end-use emissions are materially different than those for the value chain up to the end-use consumer). For simplicity, the oil and gas sectors are divided into upstream and downstream segments and then further into the subsectors of production, gathering and processing, refining, transmission and distribution.[6] The production subsector includes

6. This categorisation matches the reporting standards set by the IPCC and used in national inventories of methane emissions.

all onshore and offshore oil and gas facilities from either conventional or unconventional reservoirs. Liquefaction of natural gas, transportation either by pipeline or as liquefied natural gas (LNG) and regasification are included in downstream processes in our methane emissions estimation (Figure 10.3).

Box 10.3 ▹ Methane emissions glossary

Emissions (or emissions level) are the mass of methane emitted into the atmosphere, usually expressed in million tonnes.

Emission factor is the average rate of emissions from a specific source such as a piece of equipment, a facility or a country. The source of emissions is sometimes referred to as the activity variable (or activity data), with methane emissions often calculated by multiplying an activity variable by an assumed emission factor.

Emission intensity is the ratio of the volume of methane emitted to the volume of natural gas produced (upstream) or transmitted and distributed (downstream) expressed as a percentage.[7]

Fugitive methane emissions occur from leakages that are not intended, for example because of a faulty seal or leaking valve.[8]

Vented methane emissions are the result of intentional releases, often for safety reasons, due to the design of the facility or equipment (e.g. pneumatic controllers) or operational requirements (e.g. venting a pipeline for inspection and maintenance).

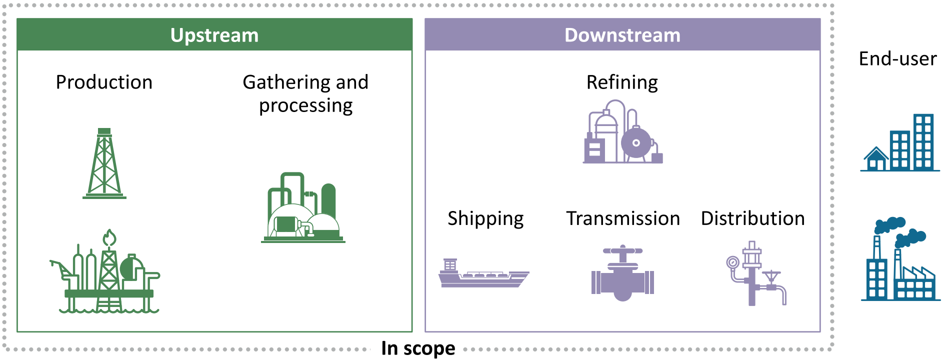
Incomplete flaring methane emissions can occur when natural gas that cannot be used or recovered economically is burned instead of being sold or vented. The vast majority of the natural gas is converted into CO_2 and water, but some portion may not be combusted and is released as methane into the atmosphere.

Super-emitters are emissions sources within a sector or subsector that account for the majority of measured or estimated emissions. Definitions vary as to how to categorise super-emitters: studies have suggested anything between the top 5-15% of sources, and some refer to the sources with the largest emissions while others refer to the sources with the largest emission factors.

7. Emission intensity data are presented in different ways by various sources. In some cases it is the ratio of natural gas emitted to natural gas produced: since natural gas is not entirely methane (the methane content can range from 80% to 100%), this will differ from the percentage used here. The ratio of methane emitted to natural gas produced also varies slightly according to whether it is presented in energy, mass or volume terms. The mass of methane emitted is converted to a volume using a density of 0.68 kilogrammes per cubic metre (kg/m^3). Marketable production is used in the denominator of the ratio. This is the volume of oil or gas that can be sold after impurities are removed and any volumes consumed onsite are subtracted; this differs from raw production, which is the volume of oil or gas that is collected from the reservoir.

8. This differs from the definition used in the IPCC Inventory guidelines (IPCC, 2006) and UNFCCC inventory accounting system (UNFCCC, 2016) in which fugitive emissions are a parent category encompassing leakage, vented and incomplete flaring emissions.

Figure 10.3 ▷ **Scope of methane emissions included in analysis**



This analysis considers emissions from oil and gas production, processing, refining, transmission and distribution but excludes emissions associated with end-user consumption

Uncertainty in methane emissions from oil and gas operations

There is a great deal of uncertainty about the level of emissions from oil and gas operations. Emissions levels and abatement potentials are based on sparse and sometimes conflicting data, and there is a wide divergence in estimated emissions at the global, regional and country levels. Here we explore the current approaches to measuring and reporting emissions from oil and gas operations and examine why there is such a high degree of uncertainty. Using a wide range of data sources and our survey of a number of countries and companies, we provide a new estimate of current oil and gas methane emissions worldwide.[9]

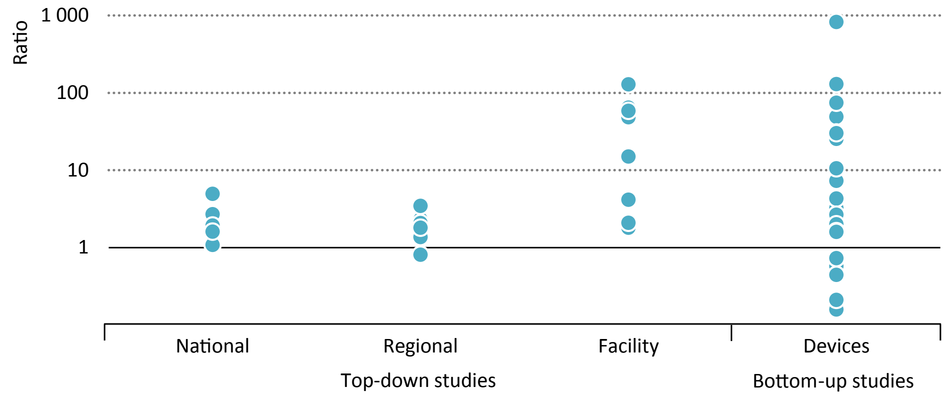
The issue of methane emissions from oil and gas operations grew in prominence as the unconventional oil and gas revolution began to take off in the United States. Analysing the methane emissions from this new source of production, some initial studies suggested there were severe leaks across the natural gas value chain (Howarth et al., 2011). These studies were controversial and leaks were later found to be lower than had been estimated (Cathles et al., 2012) but they stimulated a wave of new independent academic studies and measurement surveys. As a result, the majority of published studies on methane emissions from oil and gas operations are concerned with the United States.

Initially, the studies were top-down, relying on atmospheric samples taken at national or regional (basin) level. But it became increasingly evident that bottom-up studies were required to augment the picture. These studies demonstrated not only that there is wide

9. As part of the *WEO-2017* analysis, we conducted a survey of IEA member countries and major oil and gas producing, transmission and distribution companies. The survey sought to understand better the perspectives of the oil and gas industry as well as policy-makers concerning oil- and gas-related methane emissions and their knowledge and approaches to measuring, monitoring and reporting emissions.

variation in the emission factors at various scales (equipment, facility, regional or national level), but also that, in general, measured emission factors were much larger than the equivalent inventory or industry standard emission factors (Figure 10.4). A wide sample of measurements needs to be taken to ensure the full distribution of emissions sources are included in a survey, but there are many practical difficulties in doing so. For example, permission is required to gain site access and this may only be granted by "best-performing" companies. Moreover, facilities do not emit a constant level of emissions, potentially skewing the measurement if only a single reading is taken, while attributing emissions to a specific point source can also be problematic.

Figure 10.4 ▷ Ratio of measured emission factors to assumed or estimated emission factors from pre-2014 studies in the United States



Measured emission factors exhibit a wide distribution, but can be much larger than the assumed inventory or industry standard emission factors

Note: A ratio of one indicates that measurements and assumed emission factors agree.

Source: Brandt et al. (2014).

Recent studies have greatly improved the state of knowledge of emission levels in the United States (Marchese et al., 2015; Allen et al., 2014), and this is reflected in changes to the US Greenhouse Gas Inventory published annually since 2008. There have been a number of major retroactive revisions for US methane emissions as a result of new data, refined modelling approaches and changes in methods, all with the aim of improving the accuracy of the estimates over time (Figure 10.5). Year-on-year changes over the ten published inventories for the year 2005 vary between plus and minus 25% of the latest estimate from the 2017 report, which provides a good indication of the underlying uncertainty in estimates. Some issues have also been identified that remain to be resolved, such as how to take account of emissions from abandoned oil and gas wells, and how so-called "super-emitters" should be incorporated into the inventory (Box 10.4).

Figure 10.5 ▷ **Reported oil- and gas-related methane emissions for 2005 from the US Greenhouse Gas Inventory annual reports**

Historical methane emissions estimated for the United States have been revised considerably, highlighting the inherent underlying uncertainties

Sources: Various editions of US EPA Greenhouse Gas Inventory (EPA, 2017a).

A number of other countries, including Russia and others in Europe, have also paid attention to the issue of methane emissions for quite some time, but few comprehensive measurement studies outside the United States are available. The main source of emissions reporting is the national inventories reported by 43 countries (mostly advanced economies) to the United Nations Framework Convention for Climate Change (UNFCCC, 2016). There are, however, some problems with the generation of these numbers. In particular, many countries use the default emission intensities published by the IPCC, which are based upon datasets from the early 2000s (IPCC, 2006). These are split between emission intensities for developed and developing countries and the choice of which dataset to use can have a major impact on estimated methane emissions. For example, in its 2015 inventory, Russia used the emission intensities for developing countries and reported methane emissions of around 12.7 Mt from natural gas operations in 2013. In its 2016 inventory, it was decided that the emission intensities for developed countries were more appropriate and so Russia modified its methane emissions from natural gas operations in 2013 to around 5.8 Mt, a 55% reduction simply as a result of a change in the calculation method.[10] There are also major data gaps affecting the Middle East, Africa, South America and developing countries in Asia as a result of countries not submitting regular inventories. For these reasons, we have avoided directly using the national inventories submitted to the UNFCCC in generating our estimate of current emission levels by country.

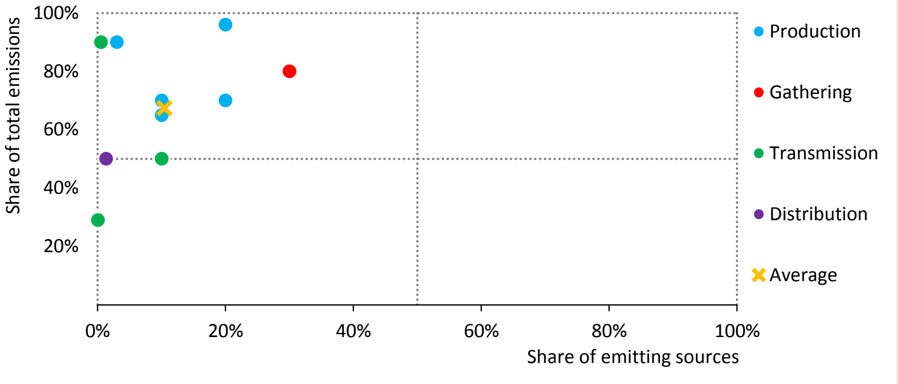
10. Russia plans to make further changes to its methane inventory as all reported sub-categories (exploration, production, processing, transportation, distribution, flaring and venting) for oil and gas will be re-assessed in the future with country-specific emission intensities.

Box 10.4 ▷ Super-emitters: what are they and why are they problematic?

There is substantial evidence that oil and gas methane emissions are highly variable across regions, supply chain routes, processes and equipment (Balcombe et al., 2017; Brandt et al., 2016). While the majority of possible emissions sources exhibit low emission rates, a relatively small number of sources have frequently been found to cause the majority of emissions. This causes a highly skewed or "heavy tailed" distribution over emissions, leading to the term "super-emitter". The top 10% of emitting sources on average contribute around 70% of total emissions (Figure 10.6).

Super-emitters can appear for both conventional and unconventional production across all stages of supply chains. Typical examples include: malfunctioning devices (e.g. valves that are stuck open), human error (e.g. accidentally leaving storage tank hatches open), and the loss of seal integrity on compressors. Most measurements to date have been gathered in the United States, but super-emitters are likely to exist across all supply chains globally. There is an unpredictable element to vents and leaks, and so super-emitters tend to be transient both in time and in geography. This complicates their detection and repair: it may nevertheless be possible to minimise their occurrence and length of duration through preventative maintenance, effective operational strategies to minimise errors, and regular leak detection and repair programmes. There would be great benefit in doing so, and it has been suggested that successfully reducing emissions from super-emitters to "normal" levels could reduce emissions by around 65-85% (Zavala-Araiza et al., 2015b).

Figure 10.6 ▷ Measurement studies for various facilities indicating the prevalence of super-emitting sources



Super-emitters exist across all supply chain subsectors, with the top 10% of emitting sources on average contributing 70% of total emissions

Source: Balcombe et al. (2017) based on studies from the United States, Canada and Russia.

Many leading oil and gas companies publish estimates of methane emissions from their operations (usually reported in annual sustainability reports). Again, there is a high degree of uncertainty in these estimates. Companies tend to estimate methane emissions at the device level using equipment counts and recognised industry standard emission factors, but the range of standards used for emission factors is wide, and it is usually the location of the company headquarters that determines which standards are applied across a company's portfolio (e.g. North American versus European industry standards). Some companies augment these estimates with direct and indirect measurements of devices and facilities. However, the scope and frequency of measurements vary widely. Although companies usually monitor emission levels, they often do not carry out any direct quantification measurements. For example, in enclosed areas, as often encountered on offshore platforms or enclosed compressor stations onshore, methane emissions need to be monitored constantly to alert operators to any leaks to avoid the potential of a flammable or explosive gas-air mix developing and endangering personnel and the installation (Bylin et al., 2010). However, while these monitors detect emissions levels, they generally do not quantify volumetric methane flow rates. Further, if a leak is detected, it may be impractical or unsafe to try to quantify the level of methane that has been emitted as the priority is to find the source and eliminate it as soon as possible.

Method for estimating current and future global methane emissions[11]

Our approach to estimating methane emissions from global oil and gas operations relies on generating country-specific and type-specific emission intensities that are applied to production and consumption data on a country-by-country basis.[12] Since emissions in the United States have been analysed more fully than those in other countries, our starting point is the 2017 US Greenhouse Gas Inventory. Along with a range of other data sources, including our survey of companies and countries, we have used this to generate separate oil and gas emission intensities for three types of production (onshore conventional, onshore unconventional and offshore) and for the downstream activities. These emission intensities are then further segregated into fugitive, vented and incomplete flaring emissions where relevant. This process provides a total of 19 separate emission intensities for upstream and downstream oil and gas in the United States.[13]

These US emissions intensities were then scaled to provide emission intensities across all other countries. This scaling is based upon a range of auxiliary country-specific data. For upstream emission intensities, the scaling is based on the age of infrastructure and type of operator within each country (international oil company, independent or national

11. Further details on the method used to generate methane emission estimates can be found in the World Energy Model section of the *WEO* website: *www.iea.org/weo/weomodel/.*

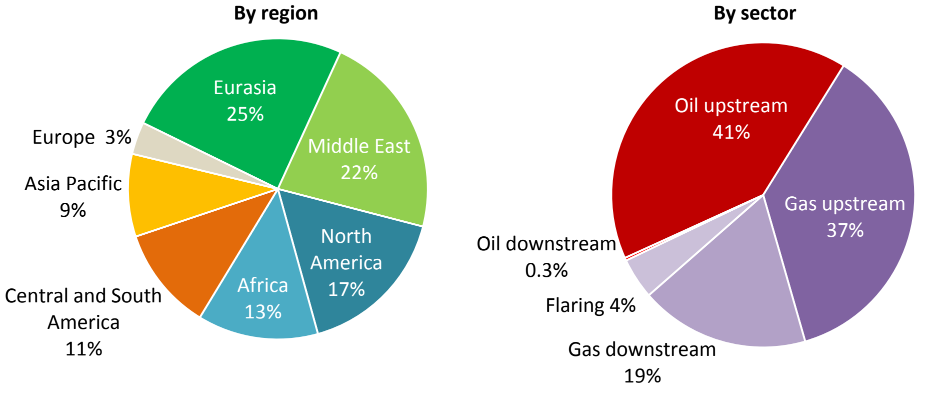
12. It is currently not feasible to generate more specific emission factors (e.g. at an equipment or facility level) at global scale because comprehensive data do not exist.

13. These 19 categories comprise the three upstream and one downstream emission intensities multiplied by two for vented and fugitive emissions, multiplied by two for oil and gas plus three for incomplete flaring from each upstream type of production.

oil company). For downstream emission intensities, country-specific scaling factors were based upon the extent of oil and gas pipeline networks and oil refining capacity and utilisation. A further factor affecting both upstream and downstream is the strength of regulation and oversight.[14] A wide range of other emission data sources were consulted to help calibrate the relative importance of these factors, including various independent direct measurement studies and confidential data provided by a number of global oil and gas companies. These auxiliary data were particularly important to scale emission intensities for Africa, the Middle East and Asia, for which there is almost no direct measured or reported data. The scaling factors that were compiled for the majority of countries lie between 0.7 and 3.6, with outliers in countries with very low regulatory strength and oversight.

We estimate global oil and gas methane emissions in 2015 to be around 76 Mt, some 55% of which are from natural gas operations (Figure 10.7). The 42 Mt emissions from natural gas correspond to a global average emission intensity of just over 1.7%. Just under 60% of total oil and gas emissions are vented (i.e. are intentional releases), 35% are fugitive (i.e. are unintentional releases) and the remainder are from the incomplete combustion of flares. The top ten countries are responsible for two-thirds of global oil and gas emissions, with Eurasia and the Middle East the two highest emitting regions: they account for nearly half of total global emissions.

Figure 10.7 ▷ Regional and sectoral breakdown of methane emissions from oil and gas operations, 2015



Natural gas operations account for around 55% of our estimated 76 Mt methane emissions in 2015, with Eurasia and the Middle East the largest emitting regions

14. This incorporates government effectiveness, regulatory quality and the rule of law as given by the Worldwide Governance Indicators compiled by the World Bank (2017).

Our estimate of 76 Mt is generally in line at the global level with the limited number of other assessments of oil and gas methane emissions (Figure 10.8).[15] However there is a very large discrepancy with the emission intensities reported by industry at the global level. One finding from our industry survey was that the majority of companies in both the upstream and downstream oil and gas sectors considered their methane emission intensities to be around 0.1% of volumes produced or transmitted. This corresponds with the findings reported in assessments by industry organisations: one recent estimate covering the emissions from 43 major oil and gas companies reported a global average emission intensity for oil and gas production of just under 0.1% (IOGP, 2015). If it were to be assumed that these companies are fully representative of the industry worldwide, then global oil and gas methane emissions would be around 15 Mt, 80% lower than our estimate (and those from other sources).

This major discrepancy requires further investigation, but we think there are three possible explanations why such a gap exists:

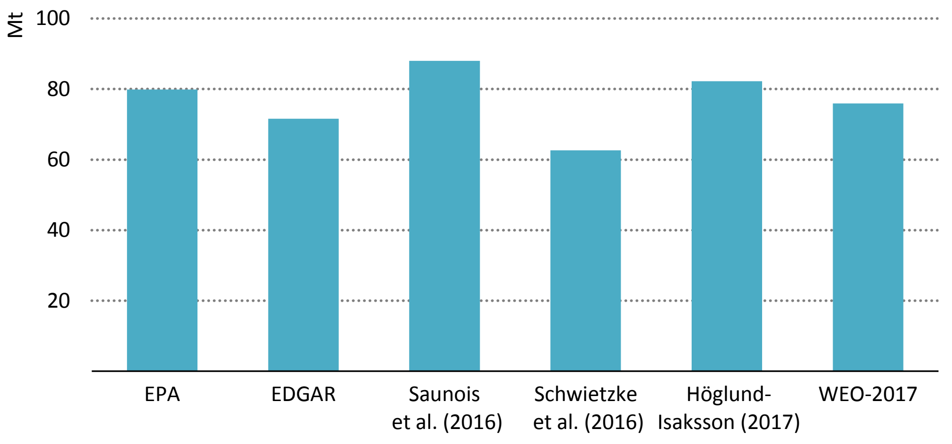
- The industry may be underestimating its emissions by relying on average emission or activity factors that are not truly representative of actual levels. This could be because the highly skewed distribution of emissions (as a result of super-emitters) is not accurately captured by the use of a single average emission factor, which is too low as a result, or because there are potential emissions sources that are not taken into account. It could also be because the default emission factors used when estimating emissions from equipment or facilities are not revised to account for leaks that are detected. The magnitude of the leak may be unknown (given the emphasis on repairing the leak rather than quantifying the level of emissions) or there may simply be no mechanism in place to modify the default emission factor used by that company.
- The dataset used to generate a global "industry estimate" may be skewed. In other words, the emission factors that have been reported by companies may not be truly representative of what is achieved by the industry as a whole. The companies that responded to our survey, or that contribute to assessments compiled by industry associations, may be those that pay most attention to emissions levels and are the "best-performers" in their peer group. Other companies not included in the dataset could have much larger emission factors and be responsible for a large proportion of emissions.
- The top-down studies may be misallocating emissions to the oil and gas sector. It could be that some emissions are assumed to originate from the oil and gas industry but in fact come from other sources such as coal, agriculture or natural sources.

With the current state of knowledge, it is impossible to be certain which of these is most likely to be correct. It is possible that more than one or indeed all may apply to a certain degree. The fundamental problem is that too few direct measurements have been taken

15. There are some larger differences in the apportioning of emissions between oil and gas within these sources. For example, Schwietzke et al. (2016) indicate that around 80% total emissions are from gas while Höglund-Isaksson indicates 40%. It is unclear, however, how these splits between oil and gas are made.

(or made available publicly) that span the variety of operators, types of operations, and countries that need to be investigated to gain a full understanding of global oil and gas methane emissions.[16]

Figure 10.8 ▷ Comparison of recent assessments of global oil- and gas-related methane emissions



Our WEO-2017 estimate of 76 Mt oil and gas methane lies in the range of other studies

Notes: As these studies were generated over the last five years, they reference different base years (or periods), ranging from 2010 to 2015. EPA = US Environmental Protection Agency; EDGAR = Emissions Database for Global Atmospheric Research.

Sources: EPA (2012); Joint Research Centre (2013); Saunois et al.(2016); Schwietzke et al.(2016); Höglund-Isaksson (2017).

SPOTLIGHT

Lifecycle greenhouse-gas emissions: how do gas and coal compare?

The CO_2 emissions from the combustion of natural gas are certainly lower than those from coal. But are they also lower when assessing full lifecycle greenhouse-gas (GHG) emissions, after taking account of methane emissions released across the natural gas value chain?

The global warming potential is often used to combine CO_2 emissions and methane into a single CO_2-equivalent term. While there are a number of problems with the use of the GWP in this way (Box 10.2), it still provides a useful starting point for comparisons between various fuel types as long as different timeframes are considered. The relative emission intensity of natural gas and coal is also affected by how the fuels are used: the conversion of natural gas into electricity tends to have a higher efficiency than coal

16. The Climate and Clean Air Coalition, Environmental Defense Fund and the Oil and Gas Climate Initiative are initiating a series of scientific studies to quantify oil and gas methane emissions and emission factors in areas outside the United States.

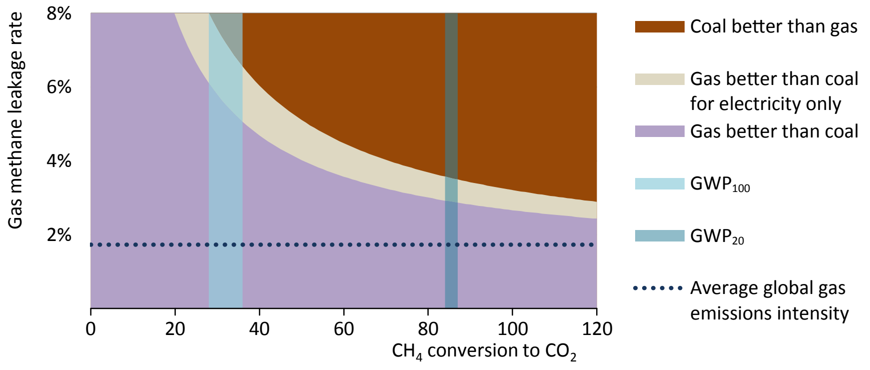
meaning that emissions are lower for natural gas if given in terms of electricity produced instead of heat. Methane emissions from coal, which we estimate to be 40 Mt globally (although this too is subject to a high degree of uncertainty), also need to be taken into account (see section 10.2.1).

Considering the relative GHG intensity of the two fuels over a 100-year timeframe, if the emission intensity of gas is below 5.5%, then gas has lower lifecycle emissions than coal (Figure 10.9). If the emission intensity lies between 5.5% and 7.5%, then natural gas would have lower lifecycle emissions for electricity, but not for heat. When considering the warming potential over a 20-year timeframe, then the emission intensity must be below 3% for natural gas to be cleaner than coal.

Our estimate of methane emissions from natural gas gives a global emission intensity of just over 1.7%. This means that gas on average generates far fewer greenhouse-gas emissions than coal when generating heat or electricity, regardless of the timeframe or GWP in question. However, the emission intensity of gas is likely to exceed 3% in some countries, in which case it would be worse than coal (measuring warming potential over a 20-year timeframe). Even if natural gas is always better than coal, however, simply comparing it to the most emission-intensive fuel is setting the bar too low. If the rapid and drastic emissions reductions required in deep decarbonisation scenarios are to be achieved, it is not sufficient for natural gas simply to result in fewer GHG emissions than coal: it is clear from the Sustainable Development Scenario that the emission intensity of natural gas needs to fall to as low a level as is practicable (section 10.4).

10

Figure 10.9 ▷ Greenhouse-gas emission intensity of natural gas compared with coal



The global average emission intensity of gas is low enough for gas to result in fewer GHG emissions than coal regardless of the timeframe considered

Notes: GWP_{20} = global warming potential over a 20-year timeframe; GWP_{100} = global warming potential over a 100-year timeframe, based on the ranges from the Fifth IPCC Assessment Report (IPCC, 2014). The average global gas emission intensity of 1.7% is based on our estimate of 42 Mt methane emissions from natural gas operations in 2015.

10.3 Tackling methane emissions

There is a variety of voluntary and regulatory efforts underway to tackle the issue of methane emissions in the oil and gas sector. The main technical challenge facing all of these efforts is how to detect and measure emissions in a comprehensive and cost-effective manner. The fundamental problem is the current lack of availability of innovative detection systems that can provide effective monitoring and quantification of emissions at low cost. The actual abatement technologies that can prevent vented and fugitive emissions, by contrast, are reasonably well-known (Box 10.5). The challenge here is to incentivise their deployment, via voluntary or regulatory means. In many cases, investment in abatement technologies is economic; the saved gas pays quickly for the installation of better equipment or the implementation of new operating procedures. However, some solutions require substantial investments that, depending on the gas price and volumes of gas saved, may not be recouped in full by the operator or may pay back only over a much longer period (and some abatement options may also be easier to implement at the design stage rather than through retrofitting existing assets). In this section, we review the experience of different voluntary and regulatory approaches, highlighting those that have led to significant reductions in methane emissions.

Box 10.5 ▷ Selected sources of methane emissions and mitigation options

There are multiple potential sources of fugitive and vented methane emissions in oil and gas operations during production, gathering, processing, and transmission and distribution. Some of the key sources are explained below along with the technologies or remedial measures that can be employed to prevent or reduce them.

Well completion: transforms a conventional or unconventional well that has been drilled into a producing one. For unconventional wells, this involves hydraulic fracturing after which a period ensues when some of the fracturing fluid flows back to the surface, potentially carrying methane with it. This was a major source of emissions when unconventional gas production first began in the United States, but reduced emissions completions (also known as "green completions") are now mandatory for the vast majority of wells.

Liquids unloading: a process where liquids are removed from the bottom of a gas well to increase the flow of gas. This can involve temporarily shutting in the well to increase pressure and then venting to atmosphere. Use of a plunger lift along with modern control technologies to conduct unloading instead can reduce emissions by up to 95%.

Glycol dehydrators: commonly used to remove water from produced natural gas. Water vapour produced in this way is typically vented to atmosphere and is likely to contain low concentrations of methane. The installation of separators or a vapour recovery unit is the key mitigation mechanism.

Compressors: maintain pressure in pipelines as gas and oil are gathered and transported. Compressors are a major source of both fugitive emissions (unintended leaks through seals) and vented emissions (gas can be released when units are temporarily shut down). Replacing seals, installing a degassing system, and moving quickly to replace moving parts are the key ways to reduce or eliminate emissions.

Pneumatic devices: control flow rates, temperatures, liquid levels and pumping systems. They use pressurised gas to create mechanical movement and can utilise natural gas since this is already pressurised. Pneumatic devices release gas by design: even though they only vent small volumes, the large number of devices that exist throughout the gas supply chain means that overall emissions can be large. Replacing these devices with electrical-driven controllers (where grid or decentralised electricity is available) or those that use pressured air rather than natural gas would eliminate these emissions entirely.

Liquid storage tanks: crude oil and condensates that are produced can be stored onsite in tanks. Methane can be dissolved in these liquids, which can evaporate, enter the vapour space of the tank and be vented to atmosphere. The main mitigation measures are to install a vapour recovery unit or to flare the natural gas.

Voluntary efforts

Increased attention to methane emissions has generated a number of national and international partnerships (Table 10.1). Many of these initiatives focus on best practices and on promoting awareness and use of abatement technologies. Some of them are oriented towards specific quantitative targets: the ONE Future initiative in the United States, for example, aims to achieve an average rate of methane emissions across the entire natural gas value chain that is 1% or less of total natural gas production. A lot of these initiatives are focussed on the United States, but an increasing number have an international dimension.

A common denominator for many of these efforts has been to improve the uptake of specific emission abatement technologies. The US Environmental Protection Agency currently lists around 70 such technologies covering compressors, pipelines, pneumatic controls, tanks, valves, wells and recommended practices for direct inspection and maintenance. The quoted capital cost range per technology varies from less than $1 000 to more than $50 000 with estimated payback periods of a few months to three years (although payback periods are highly contingent in practice on natural gas prices and the cost of capital). The use of these technologies and practices helped yield a near 30% reduction in the overall emission intensity of natural gas in the United States between 2005 and 2015 (Figure 10.10). The sustainability reports of various companies indicate that their methane emissions outside the United States have also dropped, due to the adoption of better design, leak detection and repair programmes (LDAR) and operational changes.

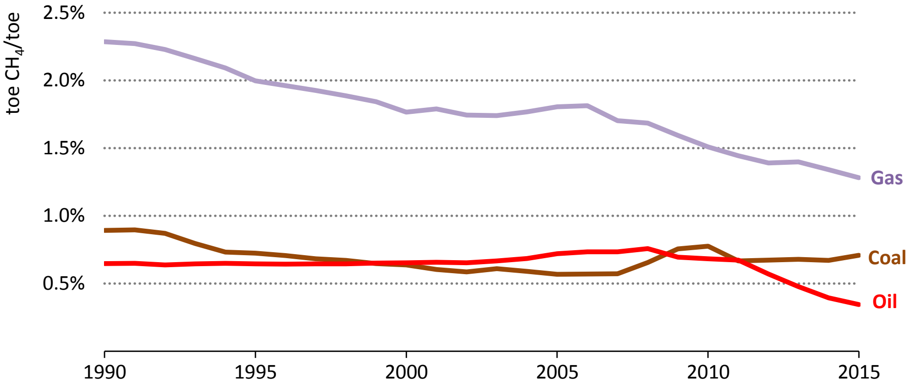
Table 10.1 ▷ Major voluntary methane emissions reduction initiatives

Name	Objective	Stakeholders / members
Natural Gas STAR Program (since 1993)	Encourage adoption of methane reduction technologies in US oil and gas industry.	US government, oil and gas industry.
Global Methane Initiative (since 2004)	Promote methane abatement, recovery, and use by focusing on biogas, coal mines and oil and gas systems.	Industry, governments, UNECE, Climate and Clean Air Coalition.
Natural Gas STAR Program International (since 2006)	Implement methane reduction technologies in international oil and gas sectors.	Industry, governments (under Global Methane Initiative).
Oil & Gas Methane Partnership an initiative of the **Climate and Clean Air Coalition** (since 2014)	Provide protocols for companies to survey and address emissions and a platform for them to demonstrate results.	Ten oil and gas companies, governments, UN Environment, World Bank, Environmental Defense Fund.
ONE Future (since 2014)	Achieve an average rate of methane emissions across the entire natural gas value chain that is 1% or less of total natural gas production.	Ten US natural gas companies.
Methane Challenge Program (since 2016)	Provide a mechanism through which US oil and gas companies can make more specific and transparent commitments to reducing methane emissions.	US EPA and 41 US founding partners (companies).
Oil and Gas Climate Initiative (since 2014)	Improve methane data collection and the understanding of the natural gas lifecycle, and select and deploy cost-effective methane management technologies.	Ten major international oil and gas companies.

Voluntary efforts to reduce emissions have to date understandably focussed on the technologies or practices with the shortest payback periods, as discussed in more detail below. Leak detection and repair (LDAR) programmes have established themselves as a key approach to reducing fugitive emissions. This involves identifying emissions via infra-red cameras on a regular basis (with the regularity being defined by the operator) and repairing leaks as soon as possible (Box 10.6).[17] Other indicators of leaks are also used, such as pressure monitoring and permanently installed monitors that check that explosive atmospheric conditions are avoided for the sake of safety, especially in offshore installations. While these voluntary programmes have yielded important emissions reductions, some data suggest that their impact may have slowed somewhat in recent years (EPA, 2015). This suggests either that most of the low-hanging abatement fruit has now been picked or that there has been a slowdown in the number of operators choosing to take voluntary emissions reduction action, raising the question of whether voluntary efforts have reached a point of diminishing returns and whether further emissions reductions may therefore require regulatory intervention.

17. Circumstances in which immediate repair may not be possible include if equipment has to be ordered, leaky equipment cannot easily be accessed or if the repair requires non-routine operational shut downs.

Figure 10.10 ▷ **Methane emission intensity of oil, gas and coal in the United States**



Mitigation efforts in the United States are bearing fruit as emission intensities have been declining since the mid-2000s; the emission intensity of coal has been more stable

Notes: Gas intensity is the sum of upstream emissions divided by US production and downstream emissions divided by US consumption. Intensities here are the ratio of tonne of oil-equivalent (toe) methane emitted to tonne of oil-equivalent fuel and so differ slightly from the other emission intensities presented (which are the volume ratio).

Source: EPA (2017).

10

Box 10.6 ▷ **What you can learn from your LDARs**

Leak detection and repair (LDAR) programmes are an essential instrument to reduce methane emissions, but standards and practices vary widely by operator and type of equipment. Not all companies undertake such programmes, but for those that do, the frequency of inspections can range from a weekly cycle to once every two to three years. Our industry survey and separate interviews with operators, conducted as part of the research for this chapter, have provided some insights into the experience of operators with their LDAR programmes:

- There is an important element of "learning by doing" with LDAR. While initial programmes can be relatively ad hoc, the assessment of risk and frequency becomes progressively more sophisticated with time.
- LDAR increases awareness of the issue, demonstrating to operators (including local staff) that leaks can occur, which can help stimulate further action on abatement.
- Maintaining detailed records of leaking components/equipment is essential to maximise the opportunities for learning. Analysis can then be used to identify opportunities for implementing early maintenance practices to prevent leaks before they occur. Analysis of LDAR results can also identify areas or sources where there is a need for more frequent surveys.

- Many leaks can be repaired immediately when observed and a significant majority of leaks can be repaired within 15 days.
- Companies support the conclusion reached in various studies that the benefits from abatement through LDAR outweigh the cost, particularly in the early period of its application.
- One company that has applied a rigorous LDAR programme confirmed that the benefits, in terms of saved gas, tend to diminish over time (as they should with effective action) while the costs tended to remain stable. The calculation of "savings" in this instance needs to account for the likelihood that emissions would increase in the absence of an effective programme.
- Emerging innovations in methane detection technology, such as aerial surveys, are likely to enable more frequent monitoring, and potentially to enable continuous detection, making it possible to find and fix large leaks much more quickly and cheaply than at present.

Regulatory approaches

There are limits to what can be achieved by voluntary action both because the pool of those willing to take such action may be limited and because the actions themselves may fall short of what is desirable from a public policy perspective. If voluntary measures prove inadequate, regulation can be very effective in reducing emissions further: for example, one study on methane emissions from the completion of natural gas wells showed that the use of green completions, which are now mandatory in the United States for new wells, reduced methane emissions during this stage of operations by about 99% (Allen et al., 2013). However, finding the right balance in regulation is challenging and of course is affected by shifts in technology and in policy priorities: in this area, as in many others, countries take different approaches.

Methane emissions can be addressed via operational safety or environmental regulations (mainly pertaining to air quality) for volatile organic compounds (VOCs).[18] Very few countries have comprehensive approaches to methane recovery and use, but a few have set specific national targets for methane emissions reduction. The most advanced body of regulation on oil and gas methane emissions is in North America. Among other major oil and gas producers, Russia and Norway are examples of the (relatively few) countries that have specific regulation on emissions.

A common element across many regulatory systems is a reporting requirement. In the United States, for example, all industrial facilities that emit more than 25 000 metric tonnes of CO_2-equivalent have to report their emissions to the federal Greenhouse Gas Reporting

18. Methane is usually excluded from air quality regulations (often phrased as "VOCs excluding methane"), but because methane emissions tend to be accompanied by emissions of other VOCs, regulating VOCs can lead to reductions in methane emissions.

Program (GHGRP). It is estimated that the data collected by this programme covers about a third of the US oil and gas methane emissions (EPA, 2017b). The data are used to track, compare and reduce emissions, and to help develop policy and regulatory approaches. A similar programme exists in Australia called the National Greenhouse and Energy Reporting scheme. In Russia, companies are required to report methane emissions (on which they are taxed), and the government has the right to conduct announced and unannounced checks to verify the reported levels, with fines for any under-reporting. In Norway, each oil and gas facility estimates and reports methane emissions annually using a common estimation method that relies on standard emission factors; methane emissions from venting are taxed.

A number of countries go beyond simple reporting requirements and have introduced specific regulatory requirements for different types of oil and gas operations. Whether at local or national level, the focus tends to be on specific areas of high risk or high potential benefit (such as those discussed in Box 10.5). In the United States, for example, several states have their own regulation and standards on methane emissions that accompany or amplify obligations arising from federal rules. California, Colorado, Ohio, Pennsylvania, Utah and Wyoming all have state-level regulations: these vary in scope, but all require mandatory inspection of facilities (via LDAR or equivalent) at varying intervals. In Canada, the provinces of Alberta, British Columbia and Saskatchewan have regulatory measures in place to address venting and flaring from upstream oil and gas operations. A further discussion of some of the key principles to be considered in the design of new regulations is provided in section 10.5.

10.4 Costs and benefits of action on methane emissions

It is clearly important to understand the scope for reductions in methane emissions from oil and gas operations, and the likely costs of achieving those reductions. In this section we combine the previous discussion on the specific sources of methane emissions, the technological mitigation options, and the voluntary and regulatory efforts that have been made, and use the information we have gathered to build a comprehensive global picture of the magnitude and costs of oil and gas methane emissions reduction. We illustrate this by constructing new "marginal abatement cost curves" for global methane emissions. These tools have been used before to examine the technical potential and costs of reducing methane emissions in countries in North America (ICF, 2016a, 2016b), but we explore new ground here by constructing state-of-the-art curves that look at the global picture to describe in detail the emissions reductions and monetary costs (and savings) that can result from the use of different abatement technology options. To build a holistic picture of the costs and benefits of tackling emissions from oil and gas operations, we then examine what different ambition levels for reducing methane emissions globally could mean in terms of actual emissions and how this might affect future climate change.

10.4.1 Marginal abatement cost curves

There are practical differences between emissions reduction action across different parts of the value chain that contribute to a wide variety of abatement costs. While replacing or retrofitting a piece of equipment on a well pad or implementing a new upstream operating practice may be relatively easy, replacing worn-out gas distribution pipes buried underground in congested urban areas is considerably more difficult. The level of emissions that comes from these different sources varies widely, and so too does the benefit in terms of the reduction in emissions. There are also likely to be some sources of emissions that are impractical to eliminate entirely: temporary emergency releases of methane may be necessary to avoid explosions, while even the highest quality compressors can vent small volumes of methane during their normal operations.

Marginal abatement cost curves are useful tools to combine all of these considerations into a single, comprehensive picture.[19] These curves take emission levels in the absence of any mitigation options and then describe the reductions that can be achieved using different technologies (by moving from left to right along the horizontal axis) at different costs or savings (as given on the vertical axis). When viewed at the global level, steps on the curve describe the reduction potentials and costs of technologies in a given country mitigating a specific source of emissions. One important aspect of these curves is that, since natural gas is a valuable product, the methane that is recovered can often be sold. This means that deploying certain abatement technologies can result in overall savings if the value received for the methane sold is greater than the cost of the technology. A complicating factor is that in some countries the operator that would need to make the investment does not own the gas (for example, the processing or transmission segments in the United States), and so would not capture the value of the methane that is recovered. However, since we examine this issue from a global, societal perspective, we assume that that any methane that is recovered can be re-sold, regardless of what contractual arrangements between different companies may be required to lead to this result. The credit obtained for selling the gas is determined by the wellhead gas price[20] in all regions (rather than the gas import prices as shown in Table 1.4) because of the need to allow for the costs of transporting the recovered gas as well as other fees and royalties that are levied. Actions that result in savings are shown below the horizontal axis in a marginal abatement cost curve: the more negative the value, the more cost-effective deployment of the technology would be.

19. The marginal abatement cost curves were generated using the IEA methane emissions model that was developed in collaboration with ICF, using IEA data and input assumptions. Further details can be found in the *World Energy Model* section of the *WEO* website: *www.iea.org/weo/weomodel/.*

20. Wellhead prices are the effective price of natural gas that an operator would use to decide whether to develop a new natural gas project. They can be calculated in a number of ways but one example is to take the price that gas can be sold to consumers and subtract the cost of transportation (including taxes) back to the location of the project.

To construct these curves we disaggregate the 19 emissions sources identified in section 10.2.2 for each country (such as vented emissions from conventional gas production) to a total of 86 equipment-specific emissions sources covering the whole oil and gas value chain (e.g. vented emissions from compressors or vented emissions from storage tanks). This disaggregation is largely based on the United States following the catalogue of emissions sources published in the US Greenhouse Gas Inventory (EPA, 2017a). However we make modifications for country-specific details based on other data sources and discussions with relevant stakeholders. For example, it is assumed that a much larger share of downstream emissions in Qatar result from LNG plants than is the case in the United States, and that gas-driven pneumatic devices are a much less significant source of emissions in many countries than is the case in the United States.

Around 50 different known abatement technology options are identified to mitigate emissions from these equipment-specific sources. Each of these technologies has a specific capital and operating cost, lifetime, emissions reduction potential and applicability (i.e. to what percentage of equipment can the technology be applied given potential practical constraints).[21] Analogues with the United States were again used for these technology-specific factors but costs and applicability were modified for country-specific details. For example, it is assumed that solar-powered electric pumps cannot be deployed as widely in high-latitude countries (and if they are, that costs will be higher) and that labour costs in developing countries in Asia are lower. LDAR programmes are the key mechanism to mitigate fugitive emissions from the production, transmission or distribution segments of the value chain. The costs of inspection differ depending on the segment in question: given travel time, it takes longer to inspect a compressor on a transmission pipeline than in a production facility. It is assumed that inspections can be carried out annually, twice a year, quarterly or monthly in the marginal abatement cost curves below, with each option appearing as a separate step. In increasing the regularity of inspections, the cost for each visit is the same but the incremental level of emissions avoided is lower. More frequent LDAR therefore costs an increasing amount relative to the amount of fugitive emissions that are avoided.

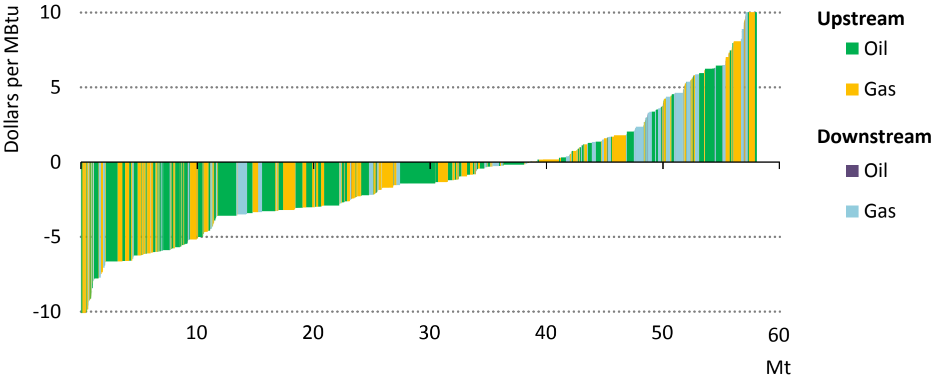
A marginal abatement cost curve describes the technical reduction potential in a specific year. The various components however will not be static over time. Oil and gas production and consumption levels change, meaning that "baseline" emissions levels will change. Natural gas prices also change, meaning that the apparent cost of technologies will change because the revenue received from selling the gas saved will differ. The costs of some technologies moreover will fall over time as a result of innovation and learning.

21. The cost and revenue from each technology is converted into net present value using a discount rate of 10% and divided by the volume of emissions saved to give the cost in dollars per million British thermal units (MBtu).

Methane emissions abatement curves

The marginal abatement cost curves for methane emissions from oil and gas operations, split by source and by region, are shown in Figure 10.11 and Figure 10.12. Of the current 76 Mt of oil and gas methane emissions, 58 Mt would be avoided if all technologies and approaches were to be deployed, a 75% reduction from current levels. With 2015 gas prices, some 50% of methane emissions (38 Mt) could be avoided just by using technologies and approaches that would pay for themselves through the captured methane that can be sold. Further reductions would start to rely on technologies or approaches that would cost money rather than saving it, either because the gas cannot be monetised (if it is flared for example) or because capital and operating costs are larger than the revenue that would be received from selling the gas recovered.

Figure 10.11 ▷ Global marginal abatement cost curve for oil and gas methane emissions by source, 2015



It is technically possible to reduce global oil- and gas-related methane emissions by 58 Mt, a 75% drop from levels today. Emissions of 38 Mt – or 50% – can be mitigated using measures with positive net present values

Source: IEA methane emissions model developed in collaboration with ICF.

The marginal abatement cost curves are quite sensitive to prevailing natural gas prices. The curves presented here rely on 2015 prices,[22] which were markedly higher than 2016 prices in a number of regions. If 2016 prices were to be used, the level of possible emissions reduction globally with measures that have positive net present values would drop from 50% to 40%.

22. Gas prices from 2015 are used in the marginal abatement cost curves presented because these are more illustrative of the prices seen throughout the New Policies Scenario.

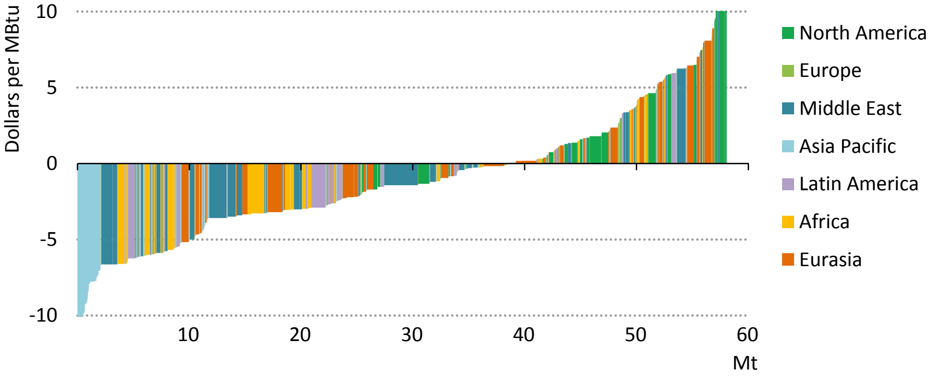
There are differences between the level of mitigation technically possible for oil and for gas: over 80% of methane emissions from oil operations can be avoided globally compared with less than 75% of methane emissions from gas. For fugitive emissions from both oil and gas, a maximum of 85% can be captured by introducing monthly LDAR programmes. It can be more difficult to apply remedial measures to some vented sources of emissions, and this is more evident for gas than for oil. While use of a plunger lift can reduce emissions from liquids unloading substantially, its effectiveness varies according to reservoir-specific properties, and it is not practicable to install plunger lifts on all gas wells (Box 10.5). The abatement potential for vented emissions from the downstream gas sector is much lower – here it is technically possible only to avoid 25% of vented emissions – as a large portion of emissions from compressors during gas transmission by long-distance pipeline are impossible to eliminate entirely, even with state-of-the-art equipment.

There are differences in the level of mitigation for oil and for gas that are possible with measures that generate an overall level of profit: over 60% of methane emissions from the oil sector can be avoided with measures that have positive net present values compared with 40% for natural gas (assuming 2015 gas prices). This is because the technical mitigation potential for upstream oil operations is higher, and because a greater proportion of oil production globally takes place in regions with higher gas prices than is the case for gas. In addition, it is more expensive to mitigate downstream emissions than upstream emissions, and while the downstream sector accounts for a very small proportion of total oil-related methane emissions (which mainly occur at refineries) it accounts for around 35% of total natural gas emissions (Figure 10.7). This is because any leaks during the transport of natural gas would cause methane to be emitted, whereas most methane is removed before oil is transported long distances. Downstream emissions for natural gas could occur anywhere along the length of the transmission pipelines and so could occur across a wide geographic area. Inspecting and repairing the potential sources of fugitive emissions therefore takes a long time. Upstream (and downstream oil) fugitive emissions are much more concentrated in discrete facilities and it is generally quicker and less expensive to inspect and repair these than is the case for downstream gas. Nevertheless, there is plenty of scope to reduce the costs of LDAR for both upstream and downstream operations, and programmes are already underway to explore the potential use of long-distance or aerial (drone based or fixed-wing aircraft) detection and measurement systems.

Since a high level of emissions can be mitigated using measures that pay for themselves from the methane recovered, an open question remains why these have not already been widely adopted. There is no single explanation for this, and reasons vary from country-to-country. Possible causes include a lack of awareness of the level of emissions or the cost-effectiveness of abatement, competition for capital within companies with a variety of investment opportunities, the measures not having sufficiently quick payback periods to satisfy companies, and the possibility of split incentives (where the owner of the equipment does not directly benefit from reducing leaks, or the owner of the gas does not see its full value). New policy and regulatory approaches might be necessary to overcome these hurdles (see section 10.5).

Regions that have the highest wellhead natural gas prices have the greatest proportion of emissions that can be mitigated at zero or negative overall costs. In many developing Asian economies the price that can be obtained for any methane recovered is relatively high (i.e. around $11/MBtu in 2015). Labour costs – a key component of the overall cost of LDAR – are relatively low. As a result, some technology options can be carried out while saving around $10/MBtu,[23] and two-thirds of methane emissions could be avoided across developing countries in Asia through the use of technologies that would pay for themselves through the methane recovered. In North America, in contrast, labour costs are generally higher and natural gas prices across the continent more closely match the price of Henry Hub (i.e. around $2.7/MBtu in 2015). Similarly, the wellhead price of natural gas in Russia and many of the Caspian countries is a fraction of the prices paid by importing countries given the cost of transport and the taxes levied on exports. However there are still a number of positive net present value measures that can be deployed: in North America, for example, around 20% of total oil- and gas-related methane emissions could be eliminated using technologies with negative or no overall costs.[24] Reducing oil and gas methane emissions remains a cost-efficient way of reducing greenhouse gas emissions compared with other mitigation strategies.

Figure 10.12 ▷ Marginal abatement cost curve for oil- and gas-related methane emissions by region, 2015



The cost of mitigation is generally lowest in developing countries in Asia and the Middle East, and generally highest in areas that have low wellhead gas prices

Source: IEA methane emissions model developed in collaboration with ICF.

23. The vertical axis on the marginal abatement cost curves is given in terms of natural gas prices in US dollars per MBtu on the assumption that natural gas is 83% methane (by energy content). So, for example, a technology with no cost of abatement with a wellhead gas price of $5/MBtu, will appear with a saving of $6/MBtu in the figure.

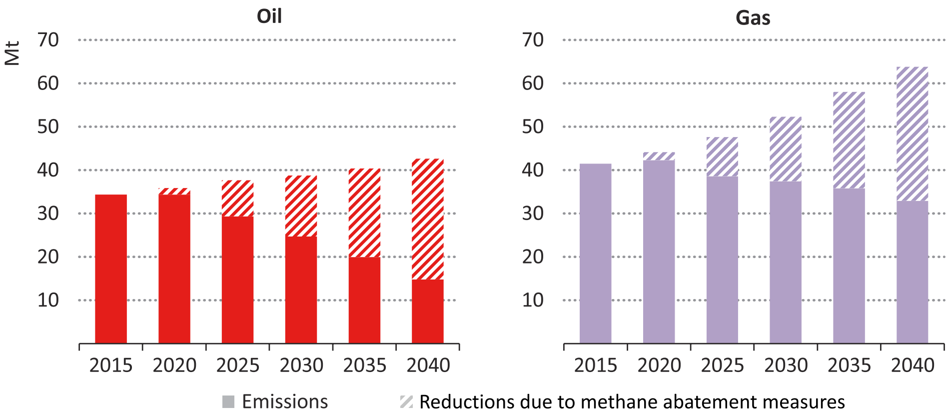
24. The finding that 20% of emissions can be reduced using measures with positive net present values is similar to that in a detailed study undertaken by ICF specifically examining North American methane emissions abatement (ICF, 2016b).

Methane emissions in the New Policies and Sustainable Development Scenarios

Changes to oil and gas production in various countries from different types of production (such as conventional or unconventional sources) affect the levels of methane emitted by the oil and gas sector. Since oil and gas prices also change, this yields a dynamic marginal abatement cost curve that evolves over time and that varies according to scenario.

In the New Policies Scenario, if there are no explicit efforts to reduce methane emissions, then methane emissions would rise to over 105 Mt in 2040. However the proportion of total emissions that could be reduced using measures that result in overall savings or have no net cost would increase to 60%, given the increase in natural gas prices around the world (the reduction is 50% at 2015 prices). The measures in place to support emissions reduction targets in North America lead to some abatement there, and it is likely that a proportion of the other emissions reductions that can be deployed while generating some level of profit would also be implemented over time. It is assumed that measures which consistently have positive net present value throughout the New Policies Scenario are fully deployed and, as a result, global oil and gas methane emissions fall to around 50 Mt in 2040 (Figure 10.13). There is a larger reduction for oil that reflects the fact that a greater proportion of emissions can be mitigated with measures that generate overall savings than is the case for natural gas. The absolute reduction in methane emissions from natural gas between 2015 and 2040 is also offset to some extent by a large increase in gas consumption over this period. Emissions from natural gas in 2040 are around 35 Mt, with the global average emission intensity for natural gas (including both upstream and downstream emissions) in 2040 falling to just under 1% (compared with 1.7% today).

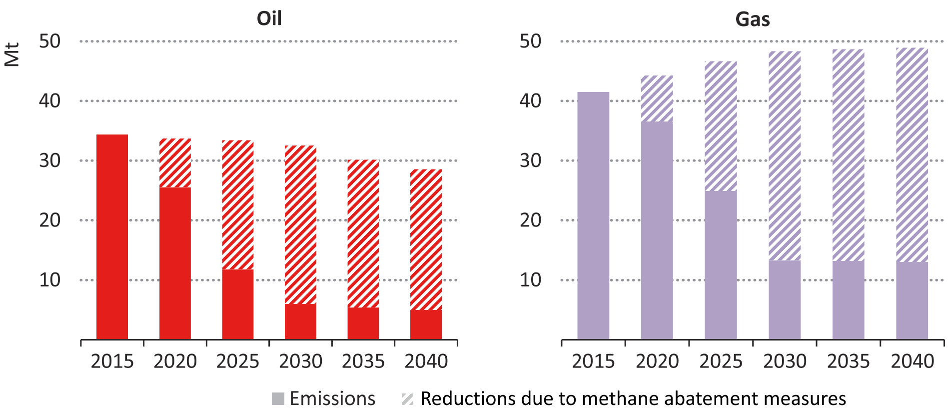
Figure 10.13 ▷ Oil- and gas-related methane emissions in the New Policies Scenario with and without abatement measures



Implementing measures with positive net present values reduces oil and gas methane emissions to around 50 Mt in 2040, 55% lower than they would have been otherwise

In the Sustainable Development Scenario, methane emissions would be lower than in the New Policies Scenario, even in the absence of any explicit methane reduction policies simply because overall oil and gas consumption is lower. As a result, the "baseline" level of methane emissions in 2040 (i.e. the level of emissions without any mitigation efforts) in the Sustainable Development Scenario would be 77 Mt, similar to today's levels. Gas prices in the Sustainable Development Scenario in 2040 are generally higher than today (although lower than in the New Policies Scenario) and so around 55% of this 77 Mt could be mitigated with measures that generate savings or have no net cost. This level of reduction is, however, unlikely to be sufficient for the use of natural gas to be compatible with the deeply decarbonising global energy system posited in the Sustainable Development Scenario. It would therefore be necessary to implement even those measures that would not pay for themselves via the value of the methane that is captured and subsequently sold. Global oil and gas methane emissions in 2040 fall to less than 20 Mt (Figure 10.14).[25] Emissions from natural gas in 2040 are just over 10 Mt with the global average emission intensity falling to just over 0.4%.

Figure 10.14 ▷ Oil- and gas-related methane emissions in the Sustainable Development Scenario with and without abatement measures



Emissions fall to less than 20 Mt in 2040, 75% lower than they would have been without any mitigation efforts

25. The 2015 *WEO* special report on *Energy and Climate Change* included a "Bridge Scenario" that aimed to reduce total upstream oil and gas emissions in 2030 by 75% relative to an "Intended Nationally Determined Contributions scenario". This is similar to the relative level of reductions seen here but there are important differences in absolute terms. The baseline level of methane emissions is different, the New Policies Scenario in this *Outlook* assumes that positive net present value measures are implemented by 2030, and the Sustainable Development Scenario contains more ambitious emissions reductions.

10.4.2 Climate impacts of methane emissions abatement

Although many actions to reduce methane emissions should save money, the key reason for tackling these emissions is to avoid the release of a potent greenhouse gas. The most common approach for assessing the impact of emissions reductions on climate change is to convert the tonnes of methane emitted (or saved) into CO_2 equivalent levels using methane's GWP.[26] However, we consider it best to avoid using GWPs when considering the climate impacts of mitigating methane emissions because this conversion is easily misinterpreted or misused and because there is such a wide divergence between the different figures that result (Box 10.2). Our approach is to use the climate model MAGICC, widely used in studies assessed in the IPCC reports (IPCC, 2014), to estimate the impact of reducing methane emissions on the average global surface temperature rise in 2100. As explained in the *WEO-2016*, the global temperature rise is almost linearly proportional to cumulative emissions of CO_2, with the amount of CO_2 emitted over a given timeframe often referred to as the "CO_2 budget". However, methane emissions also have a major impact on the temperature rise: a specific CO_2 budget can only be associated with a temperature rise by making assumptions on non-CO_2 emission rates. Since methane has a much shorter life span than CO_2, its contribution to climate change is better examined in terms of emission flows rather than cumulative emissions. A permanent reduction in the rate at which methane is emitted would increase the remaining CO_2 budget for a specific temperature rise and vice versa.

MAGICC is used to estimate the impact of the methane emissions trajectories on the temperature rise in 2100 (Figure 10.13 and Figure 10.14). We focus on the temperature rise in 2100 partly because this reflects the public and academic discourse surrounding the interpretation of the long-term temperature goals in the Paris Agreement and partly because if global CO_2 emissions were to reach net-zero in the Sustainable Development Scenario in 2100 this is approximately the date when the global temperature rise would peak. If we were to examine a closer date, say 2050 rather than 2100, the temperature impacts of policies to reduce methane emissions would be larger.

To carry out this calculation, it is necessary to extend the projection for the "baseline" level of methane emissions in the New Policies and Sustainable Development Scenarios from 2040 to 2100. Therefore assumptions are made about the levels of fossil-fuel consumption consistent with the general ambition of the scenarios. For example, if CO_2 emissions in the Sustainable Development Scenario drop to zero by 2100, this would mean that fossil-fuel

26. For example, the methane emissions reduction policies in the Sustainable Development Scenario yield an annual reduction of around 55 Mt of methane in 2040. The 100-year GWP indicates that one tonne of methane is equivalent to around 30 tonnes of CO_2, and so this reduction would be equivalent to reducing annual CO_2 emissions by 1.7 Gt CO_2-eq. The 20-year GWP indicates that one tonne of methane is equivalent to around 85 tonnes CO_2, and so avoiding 60 Mt methane would be considered a saving of over 4.5 Gt CO_2-eq.

consumption would be much lower than at present.[27] For the methane trajectories with explicit mitigation policies, reductions relative to the baseline level are kept constant from 2040 onwards separately for oil and gas. We examine the different methane trajectories, keeping all other variables constant to isolate the impact of the methane abatement policies on the median temperature rise in 2100.[28]

In the New Policies Scenario, implementing the methane emissions reduction measures that have positive net present values by 2040 (and maintaining them thereafter) would reduce the temperature rise in 2100 by 0.07 °C compared with the trajectory that has no explicit reductions. While this may not sound like a large difference, in climate terms it is immense. To yield the same reduction in the temperature rise in 2100 by reducing CO_2 emissions would require emitting 160 billion fewer tonnes CO_2 over the remainder of the century. This is a huge level of reduction. It would be broadly equivalent to the CO_2 emissions saved by immediately shutting all existing coal-fired power plants in China; or every second car sold globally from today being electric (and running on zero-carbon electricity); or immediately refurbishing all homes in developed countries to a zero-carbon standard.

The methane emissions reductions in the Sustainable Development Scenario are more stringent than the New Policies Scenario; however the "baseline" level of emissions is also lower given the need to reduce the long-term level of CO_2 emissions. The methane emissions reduction policies in the Sustainable Development Scenario lower the 2100 temperature rise by around 0.06 °C. Failure to tackle methane emissions would therefore require reducing global CO_2 emissions by an additional 140 billion tonnes CO_2 – a significant difference, especially in the context of the decarbonisation efforts already necessary in the Sustainable Development Scenario. Indeed, despite the need to reduce CO_2 emissions in the Sustainable Development Scenario, and therefore reduce fossil-fuel consumption, it remains critical to advance methane emissions reductions policies as these will still have a major long-term impact on the temperature rise.

10.4.3 Summary of costs and benefits

We estimate that between 40% and 50% of global oil- and gas-related methane emissions today could be abated by deploying technologies and abatement measures that have positive net present values. This is because the value of the methane that is saved is greater than the capital and operating costs of the mitigation mechanisms. Measures to reduce fugitive emissions in the upstream sectors that can be avoided

27. It is important to recognise that even if there are no net CO_2 emissions in 2100, this does not necessarily mean that no fossil fuels will be consumed: fossil fuels are not combusted in some sectors (notably in petrochemicals); fossil-fuel combustion can be equipped with carbon capture and storage to mitigate CO_2 emissions; and the use of some "negative-emissions" technologies could offset some level of fossil-fuel combustion.

28. The level of CO_2 emissions and other non-CO_2 forcers differ between the New Policies Scenario and Sustainable Development Scenario. If different baseline methane emissions levels were to be examined, then the impact of methane abatement policies on the temperature rise would differ.

using LDAR programmes are some of the most cost-effective, given the concentration of potential emissions sources in a small area. With a number of promising detection and measurement technologies on the horizon, these costs could fall even further. Indeed as natural gas prices rise and the cost of technologies fall, the percentage of emissions that can be mitigated at zero or negative cost will rise over time. The results vary from scenario to scenario:

- In the New Policies Scenario, in the absence of any direct emission reduction efforts, global methane emissions from oil and gas operations would rise to over 105 Mt in 2040. Given announced methane emissions reduction policies and by using technologies that would pay for themselves through the capture and sale of the methane, this is reduced to 50 Mt in 2040. The benefits of doing so are enormous.
- In the Sustainable Development Scenario, methane emissions are projected to be lower because overall oil and gas consumption is lower. Again a large portion can be mitigated using measures that would pay for themselves through the methane that is recovered. But only implementing these technologies and measures will not be sufficient in this scenario: failure to go further would make the climate objectives of this scenario harder to achieve and impede the role that natural gas can play in the energy sector transition.

10.5 An agenda for action

The actions required to tackle the issue of methane emissions from oil and gas operations need ultimately to accomplish two goals: measure and abate. The majority of the oil and gas methane assessments undertaken to date that are in the public domain are based on estimates and indirect measurements, rather than direct measurements. Yet measurement is critical not just to advance scientific understanding of the problem but also to assess the efficacy of policy actions and to assure the public that the issue is being addressed. The same is true for methane emissions from coal.

Measurement needs to be distinguished from detection and monitoring. While it may be common for the industry to monitor methane emissions levels for safety reasons, it is much less common for emissions to be quantified in a rigorous way on a continuing basis. If leaks are detected, the focus is on finding and repairing the leak rather than assessing how much methane may have been emitted. There are large data gaps for multiple major gas producing and consuming regions, including Russia and the Middle East, that need to be addressed. Policies, and the regulations to support policy goals, therefore need to ensure that measurements are undertaken, that they are robust, and that they are reported publicly.

The technologies that can reduce methane emissions are well documented, well understood and, for the most part, widely available. Furthermore, a large portion of emissions can be abated using technologies and actions that would pay for themselves through the methane saved and sold (section 10.4). But implementing abatement is often the real challenge. This is especially the case when an operator does not have a good understanding of the baseline level of emissions or have a well-established strategy to deploy emission abatement actions. Encouraging and supporting operators to quantity emission levels, undertake an assessment of the costs of abatement, and to publish results would help to identify the most cost-effective mitigation measures available and to spread best practice approaches more widely.

Alongside voluntary efforts of the sort described in section 10.3, policy and regulation will be central to overcoming these issues. Measures are likely to be best carried out in a series of stages to help maximise effectiveness and efficiency. We do not seek here to provide a detailed roadmap but rather to provide a broad overview of the key considerations and principles that could inform strategies for methane emissions reduction.

Emphasise data gathering: a first step should be to improve data gathering and reporting. Uncertainty about current emissions levels is high, and reducing this through direct measurement is critical to improve understanding of the issue, to measure progress against goals, and to develop and refine objectives and targets. One option would be to include a regulatory obligation to detect, monitor and quantify methane emissions from a sufficiently large representative sample of operations. This would include a clear set of guidelines for what is expected in terms of measuring emissions such as a standardised performance benchmark for methane detection and quantification. It might also include a requirement to measure methane emissions before any site preparation or drilling takes place for new oil and gas developments: a baseline or background level of emissions could then be established to determine whether emissions levels are related to operations that subsequently take place there.

Set an overall goal: a lack of detailed measured emissions levels should not preclude the introduction of emission abatement goals. These can be expressed both in broad, qualitative terms and also as specific, quantitative and time-bound targets. In each case, there should be provisions to update or upgrade the goal to reflect the improvement in understanding as new data become available. An announced goal can also provide an important channel for public awareness and a yardstick against which emissions data and different abatement options can be measured.

Foster innovation: the need for technology innovation that delivers reliable measurement of emissions at low cost is a key technology gap and needs to be a focus both for public support and private initiatives. Supporting research, development and deployment of technologies for methane emissions detection and measurement will facilitate emissions reductions in the future.

Maximise transparency: measurement and analysis protocols (including existing datasets) could be shared among industry and regulators to facilitate consistent approaches to quantification and abatement and to help spur implementation. A harmonised measurement performance standard would help avoid dissimilar data being produced in different countries or regions and thus promote comparisons and underpin transparency. Transparency will be valuable not just for policy-makers and regulators, but also for companies, and it will help the industry as a whole to build public confidence in abatement efforts. Measurement data, whether from dedicated site-specific studies or routine LDAR campaigns, should be made available publicly. The voluntary programme FRACFOCUS, which provides a public depositary for disclosing chemicals used during the hydraulic fracturing process in the United States, provides a potential model here. This programme is designed to help allay public concern over potential water contamination during the production of unconventional oil and gas, and provides strong encouragement for operators to reduce chemical use. A similar public-record disclosure system could be developed for methane emissions to help build trust in emissions data from the industry and actions taken to reduce methane leaks.

Ensure widespread engagement during the design of regulations: it is essential to explain why regulation is required, and then consult on how it is going to be achieved, with the aim of securing support and buy-in from as broad a stakeholder group as possible. A notable and successful feature of the approach to formulating regulations in North America was the intensive and lengthy consultation period with industry, key suppliers, academia, local communities, and environmental and non-governmental organisations.

Incentivise collaboration: industry partnerships between international and national oil companies can provide a powerful impetus to the adoption of best practices in regions where the policy and regulatory framework is less developed. Ensuring collaboration between different regulatory bodies, including those in other countries, will help to ensure consistency and facilitate collaboration, as well as encouraging the widespread adoption of best practice for regulation.

Establish sufficient enforcement: a critically important element of any regulatory approach is enforcement. Among other things, effective enforcement means deciding how oversight and regulation should be carried out, establishing which institution is to be charged with regulation or enforcement, providing leadership and resources for that institution, and working out the penalties for non-compliance.

Incorporate flexibility into measurement and abatement policies: this might take various forms, including allowing for adjustments to overall goals over time if interim milestones are exceeded or not met. The key to demonstrating progress to a given goal is the consistent measurement, reporting and verification that abatement has occurred. This can be supported by independent and transparent evaluation of policies, outcomes and the cost-effectiveness of abatement.

Focus on outcomes: in deciding the specific practices, standards, technologies, certification systems or quantitative limits to be introduced, it is important to bear in mind the overarching goal for emissions reduction, and to focus on the outcomes to be achieved. This would allow companies to choose whichever option has the lowest cost or to invest where it will be most efficient. One particular area to focus on is the timely detection and elimination of super-emitting sources. In some cases it may also be better to incentivise action by industry rather than penalise failure to comply.

Encourage new corporate thinking on methane emissions reduction: while some companies view the minimisation of methane emissions as a central pillar of their operations, others appear to attach much less importance to it. Dialogue, policies and regulatory frameworks may be able to help to change views and help to mobilise the financing necessary to achieve emissions reductions. The evolution of approaches to safety could provide a good model for the approach to methane emissions. Safety regulation was seen decades ago by some in the industry as making operations more difficult and simply adding to costs, but is today almost universally recognised as a way to ensure that the highest practicable standards are observed across the industry in day-to-day operations.

Despite many improvements in recent years, there are still a large number of questions that remain open in any assessment of methane emissions from oil and gas operations. These include the contribution of the oil and gas industry to total anthropogenic methane emissions, the efficacy and transparency of current practices for measuring and reporting methane emissions, the cost-effectiveness of abatement opportunities, and the balance between regulatory and voluntary approaches to mitigation. Yet, enough is known already to state unequivocally that reducing methane emissions from oil and gas operations is an essential component of action to address climate change. A lot is already being done, but our analysis also suggests that additional measures can be undertaken, often in ways that make rather than cost money. The case for further action is compelling. Failure to act would represent a clear risk to the environmental credentials of natural gas.

Natural gas in a changing energy world

Is gas part of the solution?

Highlights

- Natural gas demand grows in the New Policies Scenario, supporting a number of environmental goals, especially in the fast-growing conurbations of Asia. Strong growth in industrial gas consumption helps tackle local air pollution, while the ability of gas-fired power plants to operate flexibly makes them a valuable complement to the rising deployment of wind and solar PV generation.

- Increased gas use, by itself, is far from sufficient to meet global climate objectives. Yet gas demand rises in the Sustainable Development Scenario, accompanying the very rapid expansion of low-carbon technologies and improvements in efficiency. Annual gas use increases by some 20% between 2016 and 2030, reaching nearly 4 300 bcm, and remains broadly at this level until 2040. As the demand for other more emissions-intensive fossil fuels falls, gas overtakes coal in the mid-2020s and oil in the mid-2030s to become the largest single fuel in the global energy mix.

- The opportunities for gas in the Sustainable Development Scenario vary by sector and region. In the power sector, where there is scope to displace coal, as in many developing Asian economies, baseload gas generation continues to grow. Yet the main role for gas-fired power is to provide flexibility to help integrate high levels of variable renewables, reinforcing links between gas and electricity security. Industry accounts for the largest share of gas demand growth, as there are fewer low-carbon options for the provision of high-temperature heat. In transport, natural gas helps reduce CO_2 and air pollutant emissions in sectors where electrification is a less viable option, most notably in road freight and international shipping.

- The main growth markets for natural gas in the Sustainable Development Scenario are China and India, where projected gas demand is even larger than in the New Policies Scenario. Meeting demand from these markets underpins continued growth in global gas trade, most notably for LNG.

- Around $320 billion in annual investment across the natural gas value chain is required to 2040 in the Sustainable Development Scenario. Maintaining gas infrastructure remains important as natural gas provides a critical source of heat in many countries and a safety net for reliable power supply.

- The long-term role of gas will be shaped not only by the pace of the transition to a low-carbon future, but also by the success of efforts to minimise the environmental footprint of gas use. This includes progress on methane emissions reductions, carbon capture and storage and the exploration of alternative uses for gas infrastructure to convey renewables-based gases such as biogas or hydrogen.

11.1 Introduction

Reconciling rising demand for energy services with the imperative to limit harmful energy-related emissions creates potential opportunities for natural gas – especially if the issue of methane leakage is effectively addressed (see Chapter 10). By displacing more polluting fuels, gas has played a role in shaping the trajectory for lower energy-related CO_2 emissions and pollutant emissions that cause poor air quality. Today's energy world, in which coal and oil still account for 60% of primary energy consumption, continues to offer opportunities for natural gas to curb emissions in the years ahead. Although the share of natural gas in the global energy mix continues to rise in both the New Policies and Sustainable Development scenarios, the story behind the numbers is not a simple one. Countries have different starting points, domestic resources and development pathways. The scope for natural gas to substitute for more polluting fuels is shaped by the extent to which renewable energy sources and other low-carbon options are deployed, which depends in turn on the speed of the transition and the strength of targets to reduce emissions. Consequently, the role that gas plays in achieving environmental goals varies widely by scenario, across regions, across sectors, plus it evolves over time.

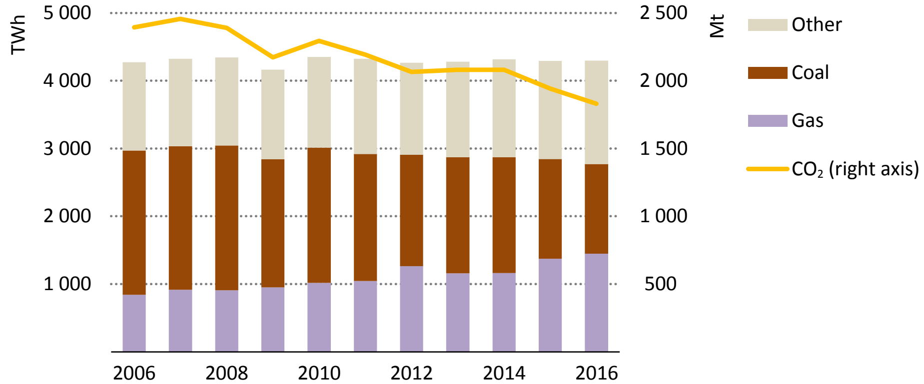
This chapter explores in detail the role of gas in a changing energy system. It uses the most recent data and our scenario projections to illustrate the areas where gas could take centre stage, where it is more likely to play a supporting role, and where it might have only a walk-on part. Although the main focus is on the role of natural gas in a decarbonising energy sector, the chapter concludes with a review of the possibilities for decarbonising the gas supply itself, whether via carbon capture and storage (CCS) or increased use of renewable gas, such as biogas or hydrogen.

11.2 Historical perspectives on coal-to-gas switching

Since the combustion of natural gas results in lower carbon-dioxide (CO_2) emissions per unit of output than is the case with coal, replacing coal with gas leads to a reduction in overall CO_2 emissions. Coal-to-gas-switching has been observed in a number of countries, with the United States offering a recent pertinent example. When domestic production from shale began to take off from around 2006, US natural gas prices fell dramatically, which encouraged the use of more gas and less coal. Nearly all of this coal-to-gas switching occurred in the power sector. In 2006, coal provided 50% of total electricity generation in the United States, while gas accounted for less than 20%. As of 2016, the share of coal was just over 30%, with natural gas overtaking coal and rising to nearly 35%. This was a major reason, alongside the expansion of generation from renewables, why US power sector CO_2 emissions dropped by nearly 25% over this period despite there being no major change in overall electricity demand (Figure 11.1). Total energy sector CO_2 emissions in the United States fell by around 15% between 2006 and 2016 – a key contributor to the flattening in global CO_2 emissions in recent years.

The availability of cheap gas was the key catalyst for the contrasting fortunes of coal and gas in the United States, but there were two other critical ingredients. The first was an availability of significant spare gas-fired power generation capacity. The second was the established liberalised electricity market: this allowed lower gas prices to feed through smoothly into changes in the power mix. These two factors were also critical for the most recent surge in coal-to-gas switching in the power sector of the United Kingdom in 2016 (Box 11.1). In the UK case, however, an additional catalyst was a relatively robust price for CO_2, which gave UK coal-to-gas switching a notable extra impetus compared with other parts of Europe where the CO_2 price was lower.

Figure 11.1 ▷ US electricity generation by fuel and related CO_2 emissions



US power sector CO_2 emissions fell by nearly 25% between 2006 and 2016, largely as a result of coal-to-gas switching

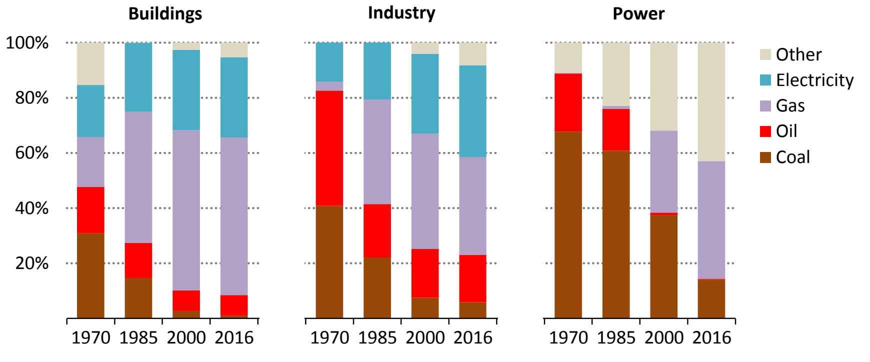
Note: TWh = terawatt-hours; Mt = million tonnes.

The conditions that led to coal-to-gas switching in the United States and the United Kingdom have some atypical features compared with the situation in many other parts of the world. No country has yet replicated at scale the US experience with shale gas. Most developing economies with large coal-fired power fleets do not have liberalised markets that would allow a quick response (in terms of generation mix) to economic conditions favouring the use of gas, nor (with the notable exception of China) is a CO_2 price on the horizon. Switching is therefore more likely to occur because of an explicit decision to favour the use of gas and to invest in new gas infrastructure (as seen, for example by the coal-to-gas switching that occurred in the United Kingdom between 1970 and 2000). Furthermore, while the impact of coal-to-gas switching on reducing CO_2 emissions within the United States and United Kingdom is unambiguous, such clear-cut examples are relatively rare. In regions with rising energy demand, if a new gas-fired power plant is built rather than a new coal plant then this may increase absolute emissions levels but reduce emissions relative to what they would have been otherwise. This is of particular importance in considering the emissions impact of constructing new gas infrastructure in developing economies and highlights the importance of comparing the role of natural gas across different scenarios and of considering linkages across the energy system as a whole. For example, if the coal displaced by gas stays in the ground, the impact of coal-to-gas switching on overall emissions levels is quite different from a case in which the coal is consumed in other parts of the economy or in other countries.

Box 11.1 ▷ Historical coal-to-gas switching in the United Kingdom

In April 2017, the United Kingdom enjoyed its first day without coal power since the Industrial Revolution. While this does not herald the final demise of coal in the United Kingdom, it underscores a trend that has been underway for many years. In 1970, coal comprised over 40% of total UK primary energy supply while natural gas accounted for less than 10%. By 2000, these shares had reversed: coal's share in the energy mix dropped to around 15% while that of natural gas rose to nearly 40%. Various phases can be identified across the end-use and transformation sectors that explain the dynamics of this transition (Figure 11.2).

Figure 11.2 ▷ Historical fuel consumption shares by sector in the United Kingdom



Rapid coal-to-gas switching in the United Kingdom occurred in the buildings and industrial sectors in the 1970s and in the power sector in the 1990s.

Note: Other includes town gas (in 1970 only), heat, renewables and nuclear.

Between 1970 and 1985, natural gas replaced coal to meet the majority of energy demand in the buildings and industry sectors. Coal consumption in both sectors fell by over 60% while natural gas soared. The contrasting fortunes for the two fuels mirrored changes in production and prices during this period: natural gas production from the North Sea more than doubled while there was a sharp fall in coal production. Retail natural gas prices dropped by over 30% in real terms between 1970 and 1980 while coal prices increased by more than 25%. This provided the impetus for both residential and industrial consumers to switch from the use of coal to gas. The transition was helped by the fact that the United Kingdom already had a network of pipes running into households which had been built for town gas,[1] around 10 million tonnes of oil equivalent (Mtoe) of which was consumed in 1970. While new high-pressure transmission and distribution pipelines needed to be constructed to transport the natural gas, it proved possible to use the low-pressure town gas pipes for natural gas.

A different picture emerges in the power sector. Gas use was only permitted from the early 1990s and the ability to use natural gas in a privatised and liberalised market, for which efficient, low-cost combined-cycle gas turbines (CCGTs) were readily obtainable, resulted in a "dash-for-gas". Around 20 gigawatts (GW) of new gas capacity was built during the 1990s, which was accompanied by a 40% drop in coal use in the power sector. Significant change in the power sector has recently reappeared on the scene: there was a dramatic 60% drop in power sector coal consumption in 2016, spurred by a fall in gas prices compared to coal, as well as by strong policy signals, including a carbon-floor price (effectively a CO_2 tax) and a commitment to the phase-out of all coal power plants by 2025. Efficiency measures and an increase in generation from renewables offset a large portion of this drop in coal use, but gas consumption in the power sector still rose by 40% in 2016.

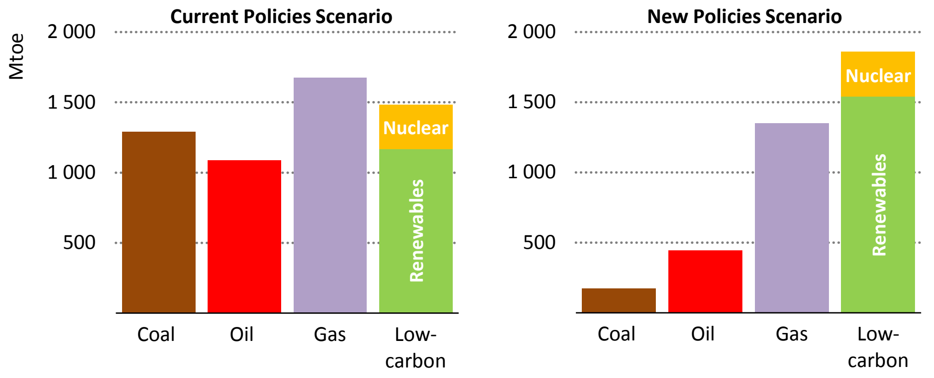
A sizeable reduction in CO_2 emissions in the United Kingdom has accompanied this coal-to-gas switching. In the power sector, for example, CO_2 emissions dropped by nearly 20% during the 1990s even though electricity generation grew by over 10%. Coal remains part of the energy mix in the United Kingdom (around 6% of primary energy supply in 2016), but the potential scope for future coal-to-gas switching is now much more limited than in the past: a situation mirrored in many other advanced economies.

11.3 Natural gas use in the New Policies Scenario

Natural gas makes a major contribution to meeting energy demand growth in the New Policies Scenario, with global demand rising by 45% between 2016 and 2040. This is distinctly higher than the pace of growth in coal demand, which rises by 5% between 2016 and 2040, and also of oil, which rises by 10%, making gas the only fossil fuel to exhibit significant growth in the New Policies Scenario (in contrast to the Current Policies Scenario) (Figure 11.3). Energy-related CO_2 emissions grow by around 150 million tonnes (Mt) each year on average in the New Policies Scenario (reaching 36 gigatonnes [Gt] in 2040), a marked slowdown in the annual average growth rate observed between 1990 and 2016 of around 450 Mt each year.

1. Town gas, manufactured from coal, is a mixture of hydrogen, carbon monoxide, methane and other gases.

Figure 11.3 ▷ Change in global primary energy demand by scenario, 2016-40



All fossil fuels grow in the Current Policies Scenario, while gas is the only fossil fuel to show significant growth in the New Policies Scenario

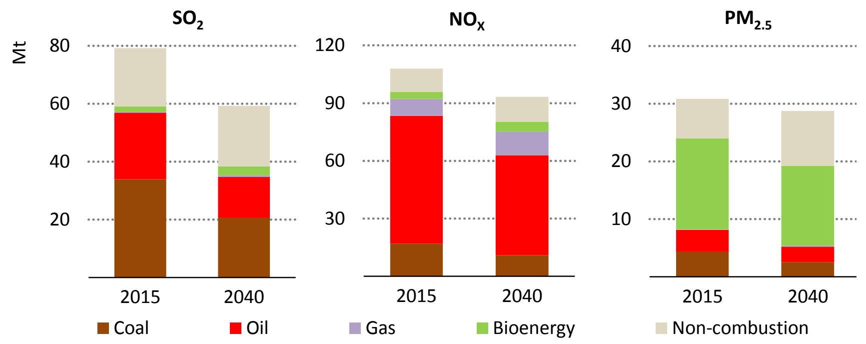
Note: Renewables are converted to primary energy equivalent using the physical energy content method, see *www.iea.org/statistics/resources/questionnaires/faq/*.

Measuring the environmental impact of natural gas consumption in the New Policies Scenario requires the examination of changes that occur at sectoral and regional levels. With a few notable exceptions (including China), gas consumption is usually not an explicit focus of sustainability policies at national level. Cost reductions for renewable technologies are opening cost-effective and direct routes to a low-emissions future, and renewables together with energy efficiency are usually the instruments of choice for policy-makers seeking to achieve environmental goals. In terms of existing emissions reduction targets, fewer than 30 of the 162 pledges made as part of the Paris Agreement explicitly mention that natural gas will be used to help achieve their goals. Growth in renewables and deployment of efficiency measures naturally leave less room for other fuels to satisfy energy demand, including natural gas. Nonetheless, the increase in natural gas plays a critical role in the New Policies Scenario in limiting the growth of coal demand, facilitating the integration of variable renewables, and reducing many local air pollutants, while ensuring that energy demand is satisfied (Box 11.2).

Box 11.2 ▷ The role of natural gas in improving air quality

The combustion of natural gas produces virtually no sulfur dioxide (SO_2) emissions and negligible levels of fine particulate matter ($PM_{2.5}$), although it does result in significant levels of nitrogen oxides (NO_X); around 10% of global NO_X emissions in 2015 came from the use of gas. Emissions of all three of these air pollutants fall in the New Policies Scenario to 2040 (Figure 11.4) and increased gas use makes a significant contribution towards a reduction in SO_2 and $PM_{2.5}$ emissions. In China, for example, the near-tripling of natural gas consumption between 2016 and 2040 helps to displace large quantities of coal, providing around 15% and 5% of the overall reduction in SO_2 and $PM_{2.5}$ emissions (respectively) in China over this period. The impact is most pronounced at the local level, where gas provides part of the solution to the debilitating air pollution problems found in many large cities. In China, gas is favoured as a way to displace coal use in small- and medium-size urban industrial facilities. Gas-fired power plants could also make a difference in other countries if the policy and regulatory environments provide the right incentives.

Figure 11.4 ▷ Global air pollutant emissions in the New Policies Scenario



Global SO_2 emissions fall by 25%, NO_X emissions by 15% and $PM_{2.5}$ emissions by just over 5% between 2015 and 2040

Note: Non-combustion emissions are process emissions in industry and non-exhaust emissions in transport.

Sources: IEA; International Institute for Applied Systems Analysis.

Outside urban areas, the largest source of $PM_{2.5}$ is the use of biomass in inefficient cookstoves in developing economies, which is most prevalent in rural locations that do not have existing gas infrastructure. Developing new networks is expensive even in areas with high population density, so the potential for pipeline gas to provide a cleaner alternative looks very limited. Natural gas can, though, play an indirect role as the extension of urban gas distribution networks can free up liquefied petroleum gas (LPG), which can then be supplied to rural consumers.

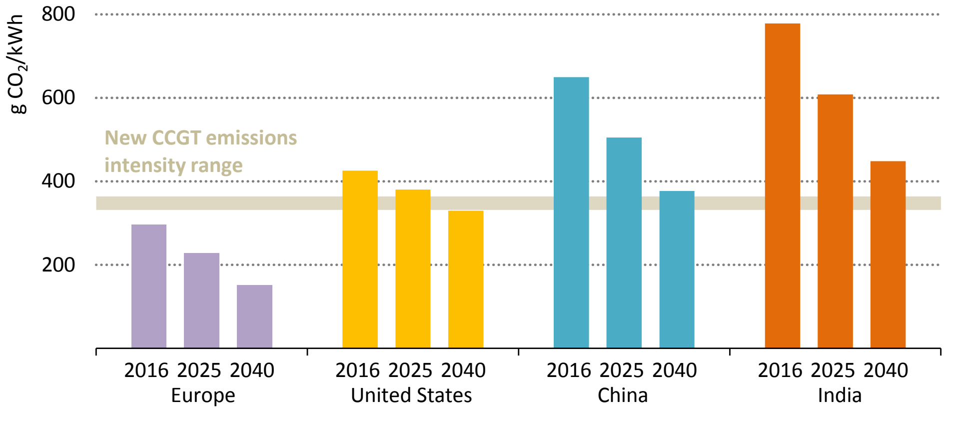
As global gas consumption rises in the New Policies Scenario, so do emissions of NO_X from its combustion and by 2040 gas is the source of around 15% of total NO_X emissions. While this is still much less than oil, the introduction of pollution control devices could reduce emissions of NO_X from natural gas further, particularly post-combustion control technologies in the power and industry sectors. However, these would require additional policy support or regulation beyond the measures that have been implemented or announced by governments.

11.3.1 Analysis by sector and region

Power sector

The power sector has been the arena for much of the recent coal-to-gas switching, but it is also the sector where renewable energy options are at their most competitive, with the prospect in many markets that the levelised costs of certain renewable technologies will fall below the level of thermal generation (see Chapter 6). Overall, low-carbon options account for two-thirds of new capacity installed in the New Policies Scenario, but investment in gas is nonetheless robust, including as an option to reduce emissions. The emissions intensity of a new CCGT is around 350 grammes of carbon-dioxide per kilowatt-hour (g CO_2/kWh). This is above the average emissions intensity in Europe (although there is a wide variation among European countries), but it lies below the average level in many other parts of the world (Figure 11.5). In these regions, this means that the addition of new CCGT plant improves the emissions performance of the power sector. In China and India, for example, around 150 GW and 90 GW of new gas-fired capacity (the majority of which are CCGTs) are projected to be installed between 2017 and 2040. These additions not only ensure these countries can meet rising electricity demand, but play a role in displacing coal power plants that might have been built otherwise and so lower the average emissions intensity of electricity generation.

Figure 11.5 ▷ Average CO_2 emissions intensity of electricity generation in selected regions in the New Policies Scenario



In key developing economies, the average emissions intensity of power generation remains above emissions from a new CCGT plant through to 2040

Similarly, in the United States, 260 GW of new gas-fired capacity is constructed between 2017 and 2040, while almost no new coal power plants are built, which helps to reduce the emissions intensity of US electricity (alongside increases in renewables capacity). In Europe, 170 GW of coal capacity reaches the end of its life over the period to 2040. Gas-fired electricity generation in Europe overtakes coal in the early 2020s and soon becomes the leading source of electricity generation (surpassing nuclear), until the late 2030s when it is overtaken by wind. The average emissions intensity of electricity falls to around 230 g CO_2/kWh in 2025 and just over 150 g CO_2/kWh in 2040.

In many markets, the space to expand gas-fired capacity further is constrained by the rapid deployment of renewables. Yet gas-fired capacity also plays an important additional role in helping to integrate variable renewables into power systems. Gas-fired power plants are relatively cheap to build (compared with other dispatchable forms of generation) and technically able to ramp up quickly when needed. This means that they are well suited to provide support if there are periods of low generation from variable sources. This applies for short-term fluctuations in electricity generation, and even more so for large seasonal variations in supply and demand. In Europe, for example, there is limited solar potential during the winter months, but significant demand for winter heating based on electricity, and gas-fired generation can step in to fill the gap. When playing this supporting role, the level of electricity generated (and volumes of gas consumed) may be relatively low, but having infrastructure capable of producing electricity when it is required is critical to ensure the stability of power supply.

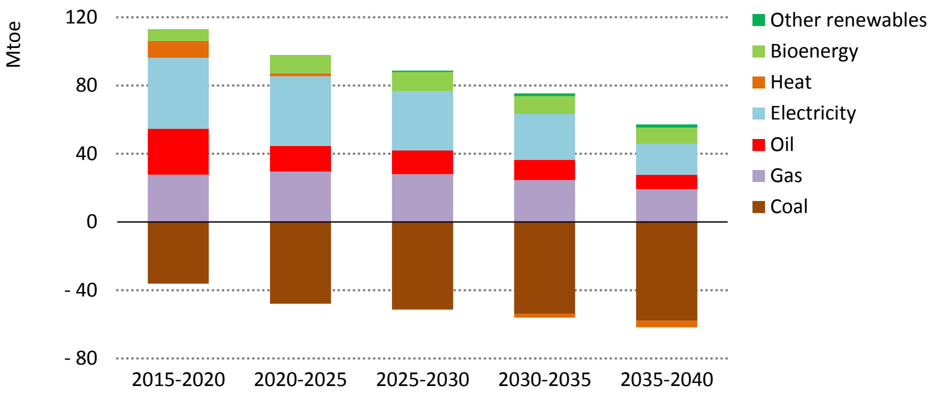
Industry sector

Industry is the sector that sees the largest increase in gas use in the New Policies Scenario: consumption grows by over 550 billion cubic metres (bcm) between 2016 and 2040, around one-third of the increase in global gas demand. Most of this growth stems from increases in the Asia Pacific region and China in particular, where gas consumption by industry increases by over 150 bcm. While gas is not the only fuel to grow in the Chinese industrial sector – the use of electricity expands and there are increases in oil consumption (as a petrochemical feedstock) and renewables – the increases in gas largely mirror the declines in coal consumption (Figure 11.6). This reflects broader changes in the structure of industrial output from heavier to lighter branches, but it is also the product of a straight substitution in many urban areas where coal-fired boilers are systematically replaced, largely with gas-fired alternatives, as part of the drive to tackle poor air quality. The increase in gas use in China is central to the 20% reduction in CO_2 emissions and a 40% reduction in SO_2 and $PM_{2.5}$ emissions from China's industrial sector that occurs between 2016 and 2040. A similar pattern of falling coal consumption and rising gas consumption is also observed in the industrial sectors of many advanced economies.

Transport sector

Gas demand in transport rises by over 200 bcm between 2016 and 2040 in the New Policies Scenario, two-thirds of which stems from increases in road transport (Figure 11.7). China, the United States and India are the main sources of this growth, where gas is used both in freight and passenger vehicles (the latter notably in India), helping to reduce $PM_{2.5}$ emissions in built-up areas. In the maritime sector, a switch away from heavy-fuel oil to natural gas occurs primarily to reduce local air pollution, most notably sulfur emissions. In October 2016, the International Maritime Organization announced plans to introduce a 0.5% cap on the sulfur content of marine fuels to be implemented from 2020 onwards (the sulfur

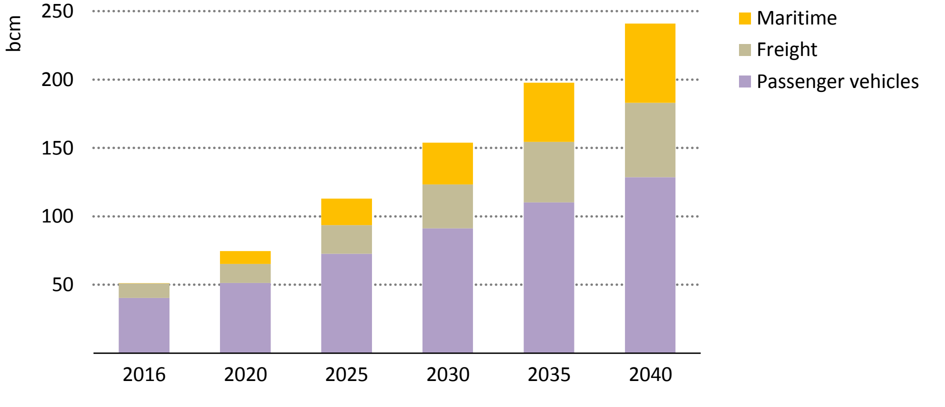
Figure 11.6 ▷ Change in industrial energy consumption in China by type in the New Policies Scenario



The growth in industrial gas consumption in China largely mirrors the decline in coal use, providing important reductions in CO_2 and air pollutant emissions

content of heavy-fuel oil is often as high as 3.5%). In the New Policies Scenario, this is met by a combination of switching from heavy-fuel oil to low-sulfur fuels (diesel or low-sulfur heavy fuel oil), the installation of scrubbers and, in the longer term, an increase in the use of liquefied natural gas (LNG) as a bunker fuel: gas use as a bunker fuel increases to 50 bcm in 2040.

Figure 11.7 ▷ Global gas consumption in road and maritime transport in the New Policies Scenario



The growth in gas consumption in road transport helps avoid $PM_{2.5}$ emissions in built-up urban areas and helps the maritime sector meet new SO_2 emissions standards

Buildings sector[2]

Natural gas use in buildings grows by around 280 bcm between 2016 and 2040 in the New Policies Scenario. Nearly all of this increase occurs in developing economies, with consumption in advanced economies broadly constant to 2040. The main expansion takes place in China, one of the few countries where a significant winter residential heating requirement is not already covered by an extensive gas distribution network. The increase in gas use in buildings in China brings numerous air quality benefits when it replaces coal and biomass (which are gradually pushed out of the system). As described in Box 11.2, increased urban residential gas use in other developing countries can also bring indirect benefits for rural areas: LPG is currently used in many urban areas for cooking and, if this is displaced by natural gas, it becomes available to be used in modern cookstoves in rural locations, where it displaces biomass. This is a major policy consideration behind the expansion of urban gas distribution networks in India. Gas use for space and water heating, and cooking in advanced economies is already widespread, and the implementation of efficiency measures avoids the need for any substantive rise in gas consumption: growth in energy demand that does occur in the buildings sector is typically met by electricity.

11.3.2 Limits to the environmental contribution of gas

A range of considerations affects the contribution of natural gas to environmental and sustainability gains in the New Policies Scenario. Given that global coal use in this scenario remains around current levels in 2040 (55% of which is steam coal for power generation), it is evident that – even with a 45% increase in global gas consumption – the scope for gas to substitute for coal is far from exhausted. There are, however, practical, commercial and policy-related reasons why coal-to-gas switching does not proceed more quickly. As discussed in Chapter 8, coal is often cheaper than gas, especially in many Asian economies where gas is imported and coal is produced domestically. There are also infrastructure constraints, which limit countries' ability to import and transport gas, while CO_2 pricing, which can tip the commercial calculation in favour of gas, but which can also further accelerate the deployment of renewables, is not widespread (Box 11.3). In some countries with large coal reserves, moreover, the emerging policy preference appears to be based on achieving emissions reductions through a combination of renewables and high-efficiency coal, rather than renewables and gas.

The clearest limitation on this role is that increased gas use, in itself, is far from sufficient to achieve international climate objectives or to provide for dramatic reductions in all air pollutants. This has long been recognised in *World Energy Outlook (WEO)* analysis; it was a central conclusion of our special report in 2011 when we asked the question "Are We Entering a Golden Age of Gas?" (IEA, 2011), "An increased share of gas in the global energy mix is far from enough on its own to put us on a carbon emissions path consistent with an average global temperature rise of no more than 2 degrees Celsius". The next step is

2. The buildings sector includes energy used in residential, commercial and institutional buildings.

therefore to examine how natural gas fares in the Sustainable Development Scenario, which explicitly targets action to tackle climate change as well as to minimise energy-related air pollution (see Chapter 3).

Box 11.3 ▻ Is CO_2 pricing the answer for gas?

Energy policies have a marked effect on the relative prices of using different fuels and one particular area of interest for gas markets is the scope and level of CO_2 pricing. If CO_2 prices are low, the use of coal may be more economic than natural gas. If prices are high this could tip the balance in favour of low- or zero-carbon sources (including efficiency measures). The impact of CO_2 prices on gas consumption will also depend on the inertia within different parts of the energy system, and so they can be expected to have a different impact over the short term and over the long term.

To illustrate, we look at the impact of CO_2 prices on power markets in the European Union and China in the New Policies Scenario. We split this into competition for fuel switching within existing infrastructure and competition between fuels for investment into new infrastructure, using the relevant prices and costs from this scenario.

For fuel switching within existing infrastructure, competition between existing fossil-fuelled power plants in countries in the European Union is fierce, as electricity demand growth is sluggish and the share of low-carbon sources is rising. A CO_2 price in the range of \$50-80 per tonne of CO_2 (tCO_2) by 2025 would expand the market opportunities for existing gas-fired power plants. In China, the rapid build-up of coal-fired capacity since 2000 has exceeded the pace needed to satisfy demand. For gas-fired power plants to displace generation from this large fleet of new and efficient coal plants would require a CO_2 price in the range of \$90-170/tCO_2 by 2025, with this range rising slightly in real terms thereafter.

For new generation capacity, a CO_2 price above \$25/tCO_2 in 2025 would favour investment in new gas-fired capacity in Europe in place of new coal-fired capacity. However, if the price were to reach \$30-40/tCO_2 the economics would start to favour onshore wind instead of gas and at \$60-120/tCO_2 would favour solar PV instead of gas. This upper bound falls over time as the costs of wind and solar PV continue to decline while natural gas prices increase: shortly after 2030 there would be no CO_2 price range at all that would favour gas (based on generation costs alone). In China, there is an even more limited window of opportunity for CO_2 prices to favour gas over renewables. By 2020, the costs of wind and solar PV are projected to fall to near parity with new gas-fired capacity, meaning that any CO_2 price would shift investment towards renewables. Gas-fired capacity offers services beyond electricity generation, notably flexibility, and if these services are valued and compensated, they will also have an impact on investment decisions. These additional revenue streams become increasingly important to support continued investment in inflexible technologies, especially where variable renewables become the lowest cost source of generation.

This demonstrates that it is impossible to indicate a single range of CO_2 prices that will encourage gas consumption. The range will vary across regions, sectors and over time and indeed in some cases a window of opportunity may not exist at all. The primary purpose of CO_2 prices is to reduce CO_2 emissions, not to support gas, and so it is not wholly surprising that the introduction of CO_2 prices will not automatically or unambiguously benefit natural gas.

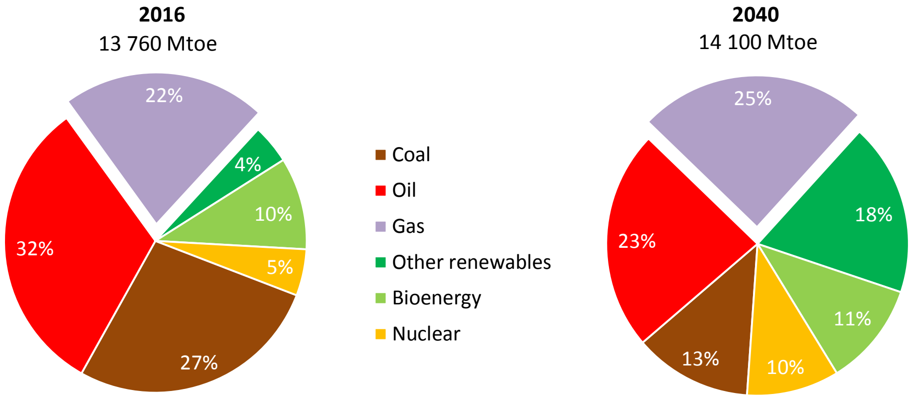
11.4 Natural gas in the Sustainable Development Scenario

Since the combustion of natural gas results in CO_2 and NO_X emissions, the opportunities for gas are naturally more constrained in the Sustainable Development Scenario than in the New Policies Scenario. Nonetheless, the characteristics of natural gas relative to other fossil fuels continue to make it an important part of many decarbonisation strategies, especially in countries where today's carbon intensity is high and in those sectors and applications where lower carbon alternatives are unavailable at scale or are less cost effective.

Overall, gas demand worldwide grows to nearly 4 300 bcm in 2030 in the Sustainable Development Scenario – some 20% higher than today's levels – before plateauing around this level. This contrasts sharply with the picture for coal and oil, which drop globally by over 50% and 25% respectively between 2016 and 2040. Gas overtakes coal in the mid-2020s and oil in the mid-2030s to become the largest single fuel in the global energy mix (Figure 11.8).

11

Figure 11.8 ▷ Global primary energy demand in the Sustainable Development Scenario



Although falling behind the combined share of renewables, gas becomes the largest single fuel in 2040

As described in more detail in Chapter 3, energy sector CO_2 emissions in the Sustainable Development Scenario fall to around 18.5 Gt in 2040, roughly half the level of the New Policies Scenario. In the 2030s, the annual decline in emissions exceeds 3%, dropping in absolute terms by over 650 Mt every year, with the largest contributions by far to these reductions coming from energy efficiency and the use of renewables in power generation, heat and transport (biofuels). CCS accounts for just under 10% of the emissions reductions in 2040, around a third of which stems from the use of gas with CCS in the power and industrial sectors. By 2040 there are 165 GW gas-fired CCS electricity plants worldwide, and around 10% of gas consumed in industry is in installations fitted with CCS. The contribution of fuel switching, largely in the form of coal-to-gas but also oil-to-gas in some transport sectors, is smaller, accounting for less than 5% of the emissions reductions in 2040.

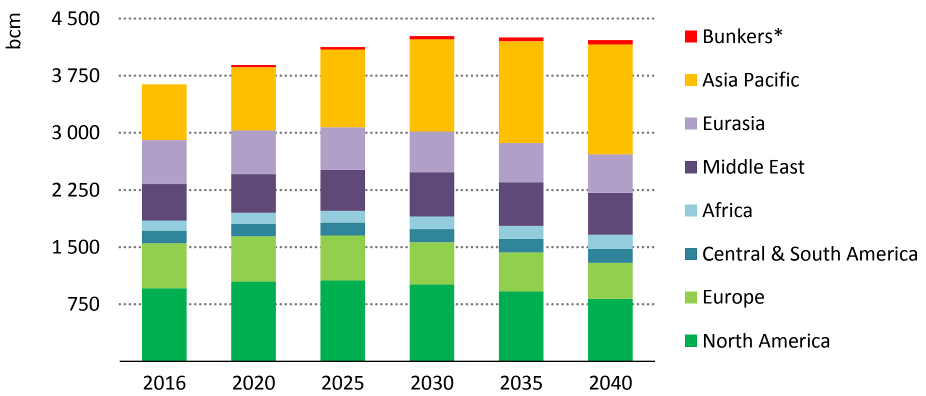
As well as limiting CO_2 emissions, the Sustainable Development Scenario aims to achieve universal energy access to modern energy by 2030 and to reduce dramatically local pollutants that cause poor air quality. Achieving universal access to modern energy by 2030 means that 1.3 billion people gain access to electricity by 2030 and 3.2 billion people gain access to clean cooking by 2030. There are also dramatic reductions in local pollutants: $PM_{2.5}$ and SO_2 emissions both fall by around 80% from today's levels by 2040, while NO_X emissions drop by 60%.

11.4.1 Analysis by sector and region

The Asia Pacific region leads the way in terms of increases in natural gas demand in the Sustainable Development Scenario (Figure 11.9). Between 2016 and 2040, demand nearly doubles, most notably in China and India, and by 2040 one-third of global gas demand is in the Asia Pacific region (compared with 20% today). In China and India, gas consumption is consistently higher throughout the Sustainable Development Scenario than in the New Policies Scenario. Gas demand in Africa and Central and South America also grows throughout the Sustainable Development Scenario, but to a much smaller extent (an increase of 70 bcm between 2016 and 2040 compared with over 700 bcm in the Asia Pacific region). In North America, gas consumption increases until the 2020s; growth then levels off and demand begins to drop from 2025 onwards. Meanwhile gas consumption in Eurasia falls steadily over the period to 2040. The slowdown in global gas demand growth, and the slight decline in total demand after 2030, reflects declines in mature gas markets outweighing the continued growth in the Asia Pacific region.

Coal's share of total primary energy demand (TPED) decreases over time in all major regions in the Sustainable Development Scenario, but there are differing patterns in the evolution of natural gas (Figure 11.10). In China and India, where coal currently dominates the energy mix and gas has a relatively small share, there are steady increases in the share of natural gas. In contrast, in Eurasia, where gas today accounts for over 50% of total demand and coal comprises a far lower percentage, the share of gas falls noticeably. The Middle East has a similar level of gas in its energy system to Eurasia but almost no coal consumption; it therefore sees a minor increase in the share of gas to 2025, but thereafter a large

Figure 11.9 ▷ Gas demand by region in the Sustainable Development Scenario

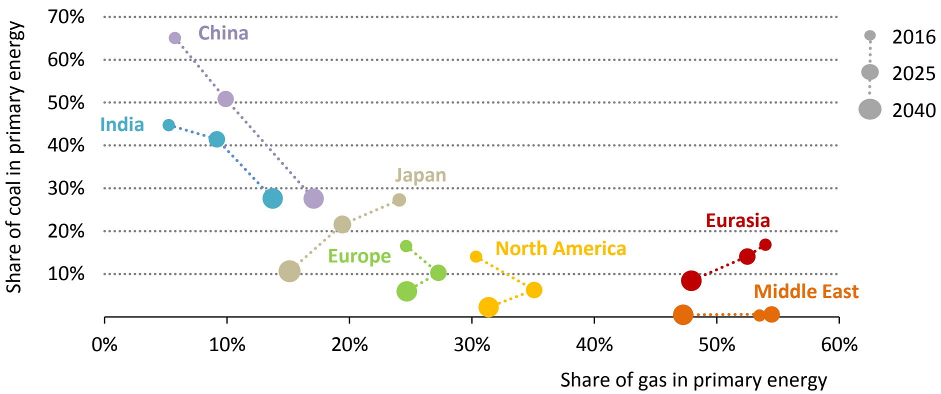


Gas demand in the Asia Pacific region grows, while demand in more mature gas markets starts to decline

* LNG used as an international marine fuel.

decrease as gas starts to become too emissions-intensive to be consistent with the emissions reductions required. In North America and Europe, where the current share of natural gas is around 25-30%, the share of gas grows markedly to 2025, to replace coal. After 2025, as renewables continue to grow apace, both coal and gas decline.

Figure 11.10 ▷ Share of coal and gas in energy demand in selected regions in the Sustainable Development Scenario



While the share of coal in total primary energy demand falls in all key regions over time, changes to the share of gas vary markedly between regions

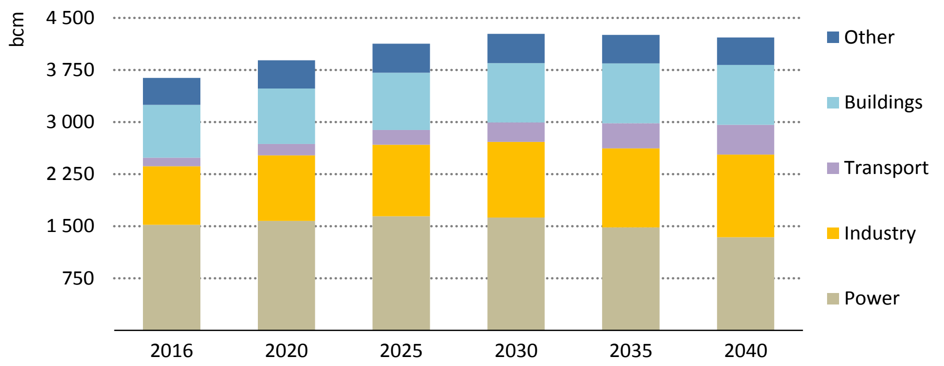
Considering these trends, regions can be broadly separated into three groups (Table 11.1). First, there are regions such as Japan and Russia, in which gas consumption falls throughout the Sustainable Development Scenario, suggesting that gas has relatively limited additional potential to help in the energy sector transition. Second, there are regions such as North America and Europe where gas consumption increases for a certain period before declining in later years, suggesting that gas has the potential to make a larger contribution to the transition than it is doing currently, but only for a limited period. Third, there are developing gas markets where consumption rises over an extended period to 2040 and gas makes a sustained contribution towards decarbonisation.

Table 11.1 ▷ Gas demand by region in the Sustainable Development Scenario relative to the New Policies Scenario

		Sustainable Development Scenario demand (bcm)				Difference with New Policies Scenario			
	2016	2025	2030	2035	2040	2025	2030	2035	2040
North America	961	1 061	1 009	916	822	1%	-6%	-17%	-28%
United States	779	871	827	740	651	4%	-2%	-15%	-26%
Central & South America	166	166	172	175	182	-9%	-16%	-26%	-33%
Brazil	36	33	35	40	45	-13%	-19%	-27%	-30%
Europe	590	593	556	516	471	-2%	-10%	-19%	-25%
European Union	463	459	420	385	342	-1%	-10%	-18%	-25%
Africa	134	157	165	173	188	-11%	-22%	-31%	-38%
South Africa	4	6	8	10	13	18%	20%	27%	25%
Middle East	477	537	579	569	547	-5%	-12%	-23%	-31%
Eurasia	575	560	536	518	508	-4%	-10%	-16%	-20%
Russia	456	434	410	386	374	-4%	-10%	-17%	-20%
Asia Pacific	732	1 019	1 209	1 335	1 441	2%	4%	0%	-2%
China	210	398	507	601	665	0%	5%	8%	9%
India	55	120	157	189	237	23%	24%	23%	30%
Japan	123	87	88	76	57	-8%	-13%	-28%	-47%
Southeast Asia	170	198	219	226	238	2%	1%	-7%	-11%
Bunkers	0	33	41	50	57	103%	57%	33%	13%
World	**3 635**	**4 127**	**4 269**	**4 252**	**4 217**	**-1%**	**-6%**	**-14%**	**-20%**

The reasons for these differing trends become clearer when we examine changes at a sectoral level (Figure 11.11). In the power and industry sectors, natural gas aids decarbonisation both by replacing coal-fired generation and by helping to integrate large shares of renewables-based generation into the power mix. In transport, gas has more limited potential to help decarbonisation but plays a critical role in reducing local air pollution. In the buildings sector, gas demand growth at a global level is much more muted, but this masks the fact that demand falls in advanced economies and rises in developing economies. In some developing economies, gas plays a role in helping to achieve universal energy access, which carries with it secondary benefits for reducing CO_2 emissions and air pollution.

Figure 11.11 ▷ **Gas demand by sector in the Sustainable Development Scenario**

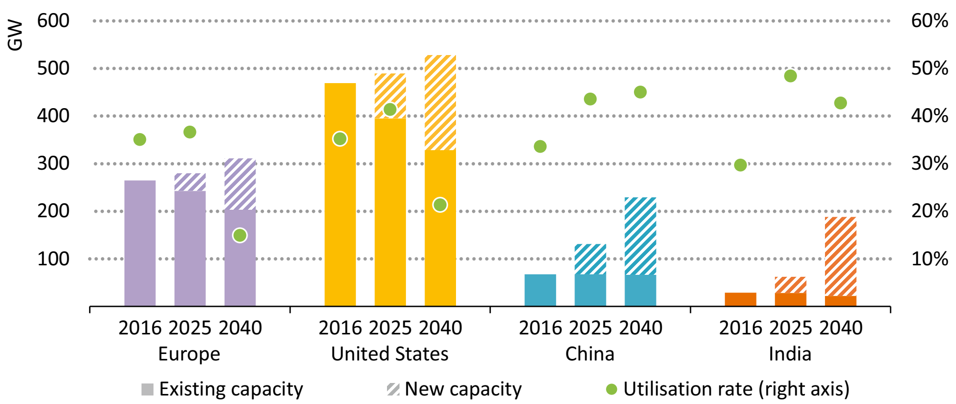


Gas use in the power sector peaks in the mid-2020s, but this is largely offset by continued growth in transport and industry

Power sector

In the Sustainable Development Scenario, the global power sector moves rapidly along the road to decarbonisation, with renewables accounting for almost two-thirds of total generation by 2040. Natural gas still has some scope to play a role in the power sector for unabated mid-load or baseload generation, and as a flexible power source to support the integration of variable renewables by providing balancing capacity: its scope potentially increases if used in conjunction with CCS.

Figure 11.12 ▷ **Natural gas-fired capacity and average utilisation rates in selected regions in the Sustainable Development Scenario**

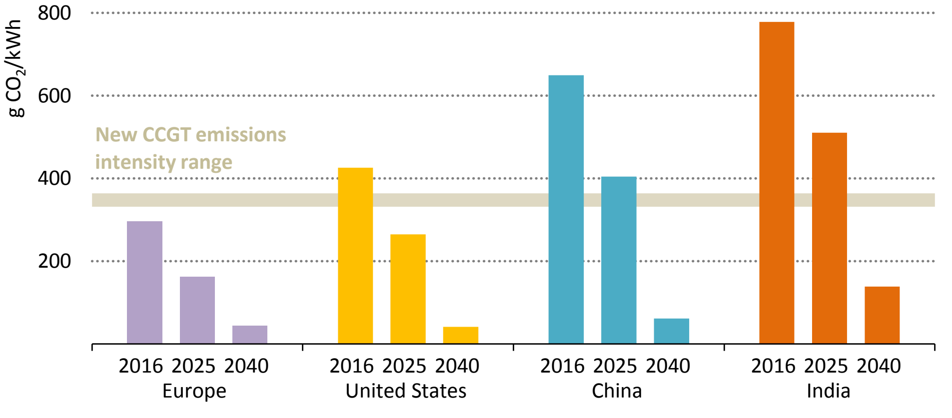


Gas power plant utilisation drops markedly after 2025 in advanced economies, despite continued capacity additions, but remains much higher in China and India

Notes: Includes gas-fired power plants equipped with CCS. Existing capacity = installed capacity as of 2016.

There is a window of opportunity for natural gas to comprise a significant share of mid-load or baseload generation in many advanced economies. In Europe and the United States, for example, there is a need to displace coal generation as quickly as possible from the electricity mix between 2016 and 2025 in the Sustainable Development Scenario. During this period, generation from variable renewable electricity technologies increases rapidly – annual average growth is around 12% in the United States and 7% in Europe – but this is still not fast enough to offset entirely the loss of generation from coal-fired power plants. In the United States, generation from coal drops by over 800 TWh between 2016 and 2025 (equivalent to losing around 20% of today's electricity generation) and, while generation from wind and solar increases by over 530 TWh, gas-fired generation is needed to fill the gap. In Europe, wind and solar offset 80% of the 520 TWh reduction in coal but, again, increases in gas generation provide much of the remainder. The average utilisation of new and existing gas-fired power plants therefore increases to close to 40% in 2025 (Figure 11.12). However, this window of opportunity is time limited: after 2025, with coal increasingly removed from power systems and an ever-increasing CO_2 price, the tide turns against the use of gas-fired generation to provide baseload supply, and utilisation rates drop in both Europe and the United States. The average emissions intensity of generation in Europe falls to just over 160 g CO_2/kWh in 2025 and to 45 g CO_2/kWh by 2040 (Figure 11.13).

Figure 11.13 ▹ Average CO_2 emissions intensity of electricity generation in selected regions in the Sustainable Development Scenario



The situation varies by region, but the role of gas-fired generation evolves quickly as the power sector decarbonises

The situation in China and India is very different: the key issue in these regions in the power sector throughout the Sustainable Development Scenario (as was the case in the New Policies Scenario) is not so much replacing existing coal power plants but rather displacing coal power plants that might otherwise have been built. The average emissions intensity of power generation in both countries still lies above new CCGTs into the late 2020s, implying that any new contribution to electricity demand by CCGTs leads to emissions savings. This means that the average utilisation rate of gas power plants stays at higher levels than in Europe and the United States (around 45%) and gas continues to form a critical component of mid-load and baseload generation. Nevertheless, by 2040, there are clear signs in this scenario that CCGTs are becoming a relatively emissions-intensive way of generating mid-load or baseload electricity.

In all regions, even if utilisation drops, gas-fired capacity continues to help with the integration of variable renewables into the power system. This does not rely on gas alone: flexibility can also come from potentially dispatchable low-carbon power sources, including hydropower and pumped-hydro storage; demand-side management (see Chapter 7); better interconnections; batteries or the use of hydrogen-based power systems (see section 11.6); or indeed from coal-fired plants. Fossil fuel use with CCS could also play this role, but this has high upfront capital costs (compared with plants without CCS) and would therefore be a very expensive means of providing back up or flexibility to the power system. The advantage of gas-fired generation, among this portfolio of flexibility options, is that it offers a way to balance not only short-term variations in supply and demand (for which a variety of alternatives are available), but also seasonal variations (for which batteries, in particular, are less suited).

Gas-fired CCS plants, however, could be used as baseload generation where high utilisation rates can help offset the large upfront capital costs. In the Sustainable Development Scenario, CCS is first fitted to gas power plants in 2025 and around 165 GW is in place worldwide by 2040. This accounts for around 7% of global gas-fired power capacity at that time, 85% of which is installed in the United States and China. While more CCS and higher levels of deployment are possible, progress on CCS has been slow to date, and a bigger role for it in future appears to depend on new financing and legal frameworks to help overcome the commercial and incentive obstacles that exist (Box 11.2).

Industry sector

The largest increase in gas consumption in the Sustainable Development Scenario is in industry, which accounts for 60% of the net increase in global demand to 2040. Gas use in light industry and in the chemical branches grows to the largest extent (by 280 bcm between 2016 and 2040). This occurs even with wider uptake of energy efficiency measures, structural changes in the sector, the displacement of gas by alternatives such as renewables and heat pumps for low-temperature heat (see Chapter 7), and increased use of bioenergy for high-temperature heat, triggered by strengthening CO_2 prices and efficiency regulations. This increase in gas demand in light industry and chemicals is significantly lower than the 475 bcm rise in the New Policies Scenario.

Demand for natural gas also increases in the energy-intensive manufacturing branches of steel and cement in the Sustainable Development Scenario. Today coal is often the most cost-effective fuel to generate high-temperature heat needed in iron and steel making because it is also used as a reducing agent and the infrastructure is in place to transport coal to the industrial facilities. This means that iron and steel making is not only very energy-intensive but also has a high average CO_2 emissions intensity (around 3 tCO_2 per tonne of oil equivalent (toe) of fuel input). In cement manufacturing, a wide variety of low quality fuels, such as petroleum coke, are combusted to generate the heat necessary to produce cement and so it too has a high emissions intensity (around 3.5 tCO_2/toe). The emissions intensity of natural gas is around 2.3 tCO_2/toe, so fuel switching to natural gas brings significant emissions reduction benefits in these industrial branches. Some zero-carbon options to generate high-temperature heat (such as the use of bioenergy) are also available.

Another option that could yield even larger emissions reductions in iron and steel production and cement is to use natural gas with CCS. However, in many industrial facilities it would probably be more economic to continue to use the current fuel source, often coal, and to equip it with CCS, rather than both to convert to the use of natural gas and to equip with CCS. As a result, the uptake of natural gas fitted with CCS in the industrial sector in the Sustainable Development Scenario is lower than for other fuels: 10% of industrial gas use is fitted with CCS in 2040 compared with around 20% for coal. The use of gas in iron and steel making (as well as in aluminium production) is also affected by increased recycling efforts. The re-melting of recycled scrap requires processes that predominantly use electricity, such as an electric arc furnace, rather than natural gas.

Transport sector

Switching to natural gas offers a way to reduce both air pollution and CO_2 emissions in parts of the transport sector. Gas demand in this sector more than triples by 2040 in the Sustainable Development Scenario, and increases by a factor of five in the road transport segment. While electrification is the preferred route to low-emissions mobility for passenger cars (in most cases), gas makes a notable contribution to emissions reductions in road freight and shipping.

The key factor currently holding back the adoption of natural gas in road transport is the lack of refuelling stations. Vehicle natural gas use in the Sustainable Development Scenario therefore expands most in regions where natural gas consumption in the residential and industry sectors supports the required infrastructure. Additional policy support is vital for this to occur. The stringent fuel-economy and emissions standards introduced in the Sustainable Development Scenario reduce oil consumption for transport, but also tend to discourage the use of natural gas in advanced economies. In China and India, the desire to develop networks for electric charging stations may edge out a widespread development of natural gas refuelling stations. Nevertheless, the need to tackle air pollution rapidly means that natural gas can play an important role during the transition when electric vehicles are still in their initial deployment phase, or in specific transport sectors such as road freight, where natural gas is one of the few alternative fuel options that can reduce both air pollutant and CO_2 emissions. Global gas use in road freight grows by around 80 bcm between 2016 and 2040 in this scenario. Gas use in road transport makes particular progress in the Middle East as the widespread availability of inexpensive natural gas makes it economic in both freight and passenger vehicles.

In the maritime sector, the use of LNG rather than heavy-fuel oil as a bunker fuel could provide around a 25% reduction in CO_2 emissions. While this is an important reduction, it is not sufficient to achieve the CO_2 emissions reductions required under the Sustainable Development Scenario: enhanced energy efficiency measures, the use of wind assistance and advanced biofuels are all necessary to avoid an increase in emissions. There is a push to eliminate sulfur emissions beyond the announced 0.5% cap on the sulfur content of marine fuels to be implemented from 2020 onwards in the Sustainable Development Scenario, and this is the key reason why consumption of gas as LNG grows to nearly 60 bcm in 2040 (15% higher than in the New Policies Scenario).

One key risk for the use of natural gas as a transport fuel is the potential for "methane slip". This is when some fraction of the natural gas used in an engine is not fully combusted and escapes as methane to the atmosphere. Recent reports have suggested that methane slip in ships could be as high as 2-3% of gas consumption (Ricardo-AEA, 2016). Methane is a more potent greenhouse gas than CO_2 and so unless this is controlled it could eliminate a large portion of (or even in some cases perhaps exceed) the potential emissions savings from the lower combustion emissions of gas compared with oil (see Chapter 10).

Buildings sector

The main role played by natural gas in the buildings sector in the Sustainable Development Scenario is to help achieve universal energy access.[3] This occurs primarily through the expansion of local gas distribution networks in urban areas such as Lagos and Delhi. Not only does this provide a basic level of energy to many but it also expands the overall level of energy service demand. As discussed, the expansion of gas is generally limited to urban areas but this can still be to the benefit of rural locations, as LPG that is displaced in urban areas can then be used in rural ones. The use of natural gas to help achieve energy access also has some positive secondary effects on decarbonisation and air pollution. Replacing LPG with natural gas helps to reduce both sulfur and CO_2 emissions, while replacing the use of bioenergy almost entirely eliminates emissions of particulate matter. Residential gas use in the Sustainable Development Scenario in developing economies grows by 85 bcm between 2016 and 2040, in addition to a 105 bcm increase in the services sector.

The situation is different in advanced economies, where achieving energy access is not an issue. Gas distribution networks continue to provide a valuable energy service to consumers in the residential and service sectors, as their wholesale replacement is not cost effective, but gas consumption nonetheless declines due to the implementation of stringent efficiency measures. At the margin, and for new buildings in some markets, the installation of new gas boilers increasingly gives way to technologies such as solar water heaters and heat pumps. These are already competitive in Japan and France, and become competitive in an increasing number of markets as technology learning and economies of

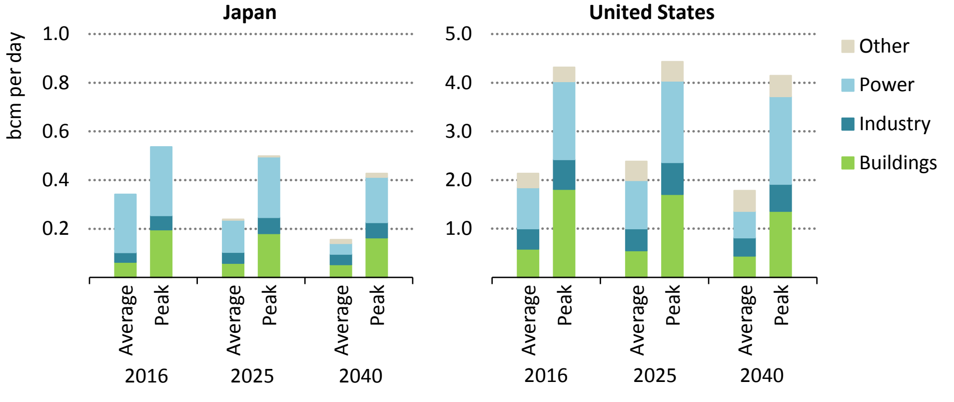
3. Also see *Energy Access Outlook: from Poverty to Prosperity*, *World Energy Outlook Special Report* (IEA, 2017a).

scale help to reduce costs (and as domestic gas prices increase from today's levels). Gas use in buildings in advanced economies falls steadily throughout the Sustainable Development Scenario by 90 bcm between 2016 and 2040, some 20% below today's levels.

Focus: The role of gas infrastructure

The optimal layout and size of mid-stream gas infrastructure, transmission and distribution networks in particular, depends on the variability of gas consumption and, importantly, the maximum level of gas consumption within a year (often called peak gas demand). In regions with a high share of gas use for heating, such as in North America, the European Union and Russia, gas infrastructure that can handle major differences in gas demand between a summer day and a winter day is essential.[4] Many developing economies face rapidly rising gas demand in both the New Policies and Sustainable Development scenarios and have yet to develop fully their gas infrastructure. Understanding differences between average and peak demand is therefore important to ensure that infrastructure in these economies is designed accordingly.

Figure 11.14 ▷ Average and peak natural gas demand in Japan and the United States by sector in the Sustainable Development Scenario



Natural gas use for heating and power generation drives peak gas demand

The relationship between average gas demand and peak gas demand within a country depends on the composition of sectoral demand (Figure 11.14). The contribution of the industry and transport sectors to a country's peak gas demand is quite predictable, broadly proportional to changes in annual demand, but the heat and power sectors are much

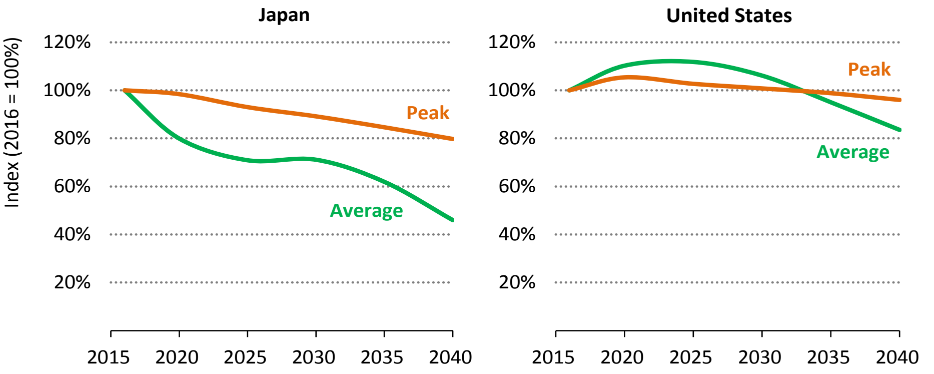
4. This demand seasonality is also reflected in a marked spread between summer and winter gas prices in these countries, which has underpinned investment into seasonal gas storage.

less straightforward. Gas-fired power plants are an important provider of flexibility, and so, even if installed gas capacity lies idle for large parts of the year, there may be individual hours or days when nearly all of the available capacity is used to balance the natural fluctuations of variable renewable sources. For heating in buildings, electrification reduces average gas demand, but does not necessarily decrease peak demand significantly if the electricity powering the heating systems is generated using gas-fired power plants. For systems with high winter heating demand and a large share of solar photovoltaic (PV) in their generation mix, the strains on the gas network may therefore be significant even if overall gas demand is in decline.

In the Sustainable Development Scenario, two-thirds of the growth in gas consumption in developing economies between 2016 and 2040 is in the industry and transport sectors. Demand growth for winter heating is minor (with the exception of China) and where gas is used in buildings for cooking or water heating there is limited seasonality in demand patterns. The challenge for many developing economies in designing gas networks is therefore very different to that faced by many of today's mature gas markets when they were planning their infrastructure: there is in particular a much smaller need for seasonal storage infrastructure (although storage may still be needed for security of supply purposes).

The evolution of peak gas demand also governs the amount of existing gas infrastructure that has to be maintained in mature gas markets in order to safeguard energy security. In Japan, for example, average gas demand in the Sustainable Development Scenario drops by over 50% between 2016 and 2040, yet peak demand only falls by 20% (Figure 11.15). Similarly, in the United States average gas demand drops by 16% over the same period, yet peak demand falls by less than 5%. In systems where gas demand and peak load are both in decline, it is safe to assume that existing infrastructure is broadly capable of handling the projected changes in utilisation. However, investment to maintain this infrastructure is critical: while this maintenance and refurbishment investment can potentially fall over time, it can only fall in parallel with peak demand rather than average demand. Furthermore, there may be a higher need for flexible natural gas storage that can provide gas promptly at times of peak demand. There may be little economic incentive for market operators to maintain equipment that they expect to be needed only very occasionally. Capacity markets have been developed in some countries wherein companies receive revenue to maintain electricity generation capacity so that it is available when needed. Similar mechanisms may be needed to maintain gas distribution and storage infrastructure: while the overall volumes of gas consumed in many regions may be lower than at present, it is critical to have volumes available when they are required. With power sector balancing needs increasingly important for peak gas demand, gas security and electricity security become ever more closely linked, requiring an integrated policy approach.

Figure 11.15 ▷ Average and peak natural gas demand in Japan and the United States in the Sustainable Development Scenario



Peak gas demand falls by less than average gas demand over period to 2040

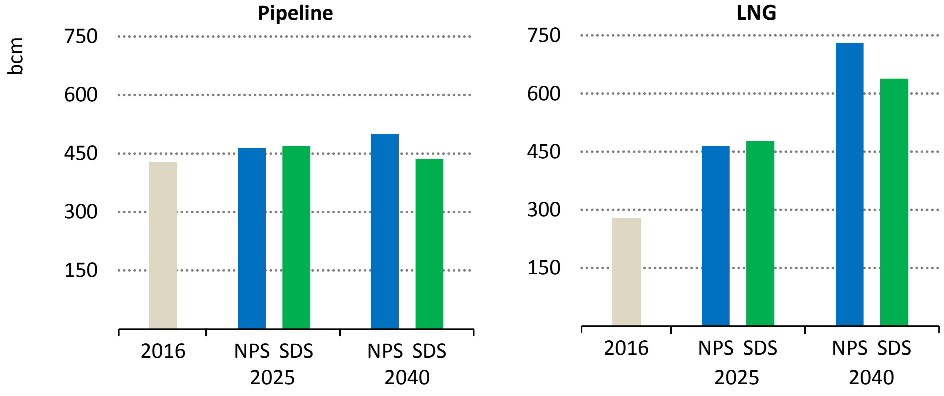
11.5 Trade and investment

LNG and pipeline trade

Inter-regional gas trade grows throughout the New Policies Scenario: pipeline trade increases by around 20% between 2016 and 2040, while LNG trade soars by more than 150%. As a result the volume of gas traded over long distances by LNG surpasses that traded by pipeline in the mid-2020s (Figure 11.16). The growth in pipeline and LNG trade in the Sustainable Development Scenario over the period to 2025 is broadly similar to that in the New Policies Scenario. During this period, the bulk of the increase in global pipeline trade comes from a 55 bcm increase in exports to China (see Chapter 9). Global pipeline trade peaks soon after 2025 in the Sustainable Development Scenario, with exports to Europe from Russia falling by around a third between 2025 and 2040. Russia offsets some of its losses to Europe by increasing exports to China, but it faces stiff competition from countries in the Caspian region and so by 2040 its pipeline exports have fallen back to 2016 levels (having been over 20% higher in the mid-2020s).

Global LNG trade in the Sustainable Development Scenario continues to grow at a robust pace to 2030. LNG imports to Europe, Japan and Korea remain broadly flat throughout the 2020s, but demand for LNG continues to grow in developing economies in Asia. LNG is critical in these regions to meet energy demand that might otherwise be provided by coal. After 2030, LNG demand in Europe, Japan and Korea drops by 30%, offsetting most of the sustained growth in other Asian countries. The United States and Australia lead the way in terms of LNG export growth in the first ten years of the Sustainable Development Scenario, but there is also around 35 bcm growth in exports from both Russia and the Middle East. After 2025, the largest contribution to LNG markets comes from the United States, where exports expand to just over 140 bcm in 2040.

Figure 11.16 ▷ **Global pipeline and LNG trade by scenario**



Pipeline and LNG trade grow to a similar extent to 2025 in both scenarios. Trends then diverge, with the New Policies Scenario seeing more growth in LNG trade.

Note: NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

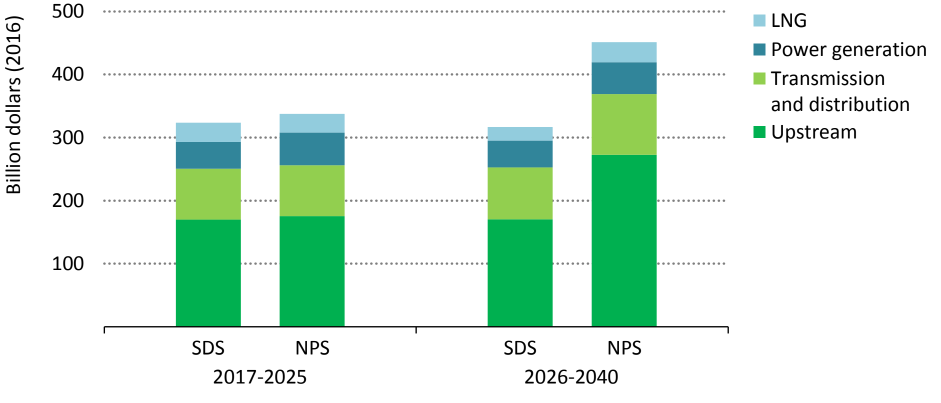
The relative merits of pipeline and LNG trade in the Sustainable Development Scenario are affected by how much gas is used in transporting it to its destination. In pipelines, a portion of the gas transported is consumed in compressor stations to maintain pressure and allow the flow of the gas. In LNG, liquefaction of natural gas prior to transport is an energy-intensive process requiring the gas to be cooled to -162 °C. The gas flowing to the often-remote facility is generally used to provide this energy and around 10% is consumed as a result (although this percentage varies seasonally and regionally). There are further (albeit smaller) losses during shipping, referred to as “boil off”, with gas often used to power the LNG tanker and regasification.

Gas consumed during both modes of transport depends on the distances involved but generally, at present, LNG results in higher gas use for transportation. For example, around 7% of the gas transported by pipeline from Russia to Europe is consumed, while 13% would be consumed for LNG travelling a similar distance. In the Sustainable Development Scenario, CO_2 taxes are imposed on most major energy consuming sectors and, if applied to the transport of natural gas, would result in meaningful increases to transport costs. In 2040, for example, CO_2 prices are \$140/tCO_2 in Europe and \$125/tCO_2 in Russia, which could increase the cost of pipeline imports by around \$0.5 per million British thermal units (MBtu) and LNG imports by close to \$1/MBtu. There are options to reduce these emissions to mitigate these increases: LNG facilities could use solar power for the liquefaction process rather than the incoming natural gas, while compressors in new transmission pipelines could tap into the electricity grid rather than generating power on-site using natural gas. These options would reduce the proportion of gas that is used during transformation and transmission as well as the overall level of CO_2 emissions.

Investment in natural gas infrastructure[5]

On average $360 billion annual investment into the natural gas supply chain is needed in the New Policies Scenario to 2040 (a cumulative investment of $8.6 trillion).[6] The largest share, averaging nearly $240 billion every year, is for the upstream (Figure 11.17) this is necessary not only to meet the 45% increase in demand over the period to 2040, but also to offset the underlying declines in gas production. The observed decline rate for conventional gas fields that have passed their peak is over 7% per year and the decline rate for unconventional gas production is even steeper. There is also $90 billion annual investment in transmission and distribution gas networks, half of which is required to maintain existing networks in mature regions (North America, Europe, Japan, Korea and Russia).

Figure 11.17 ▷ Average annual investment into gas infrastructure by scenario



Investment to 2025 is broadly similar in the Sustainable Development and New Policies Scenarios but a sharp divergence emerges thereafter, particularly in the upstream sector

Note: NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

Cumulative investment in the Sustainable Development Scenario between 2016 and 2040 is just over $6.5 trillion. However, the trajectory of gas demand over this period poses a variety of challenges for investment in related infrastructure. Investment in new assets has to be sufficient to meet rising gas demand in the short term while being as compatible as possible with the transition over the longer term. Average annual upstream gas investment remains around $170 billion in the Sustainable Development Scenario; in the period after 2025 this amount is needed not to satisfy any major increase in demand but rather to offset

5. Infrastructure is used here to refer to assets along the natural gas value chain including supply, mid-stream assets, such as LNG and transmission and distribution pipelines, and gas-fired power plants.

6. Investment values for upstream natural gas include the capital costs of associated gas and non-associated gas assets and make allowance for how investments for natural gas liquids are shared between oil and gas.

underlying declines in production. In contrast, demand for LNG begins to wane after 2030 in the Sustainable Development Scenario and few new facilities are needed: the average level of investment in the period after 2025 is therefore 30% lower than the level before 2025.

Differences between the New Policies and Sustainable Development scenarios help inform which major investment decisions made in the short-to-medium term could be termed "no regret" options. The level of LNG trade and investment into new export terminals is broadly similar over the next ten years in the two scenarios: while operators may receive less revenue in the Sustainable Development Scenario (since prices are somewhat lower), it should still be sufficient to provide a reasonable rate of return. Similarly, new pipelines transporting natural gas to China as well as the infrastructure to distribute and consume it (especially in the power and industry sectors) are needed in both the New Policies and Sustainable Development scenarios: the upstream projects supplying these emerging markets also remain robust. After 2025, with a discernible slowdown in the growth in natural gas demand in the Sustainable Development Scenario, average annual investment globally is around 30% lower than the New Policies Scenario raising the question of whether there is a risk of some natural gas assets becoming stranded.

Focus: Stranded natural gas assets[7]

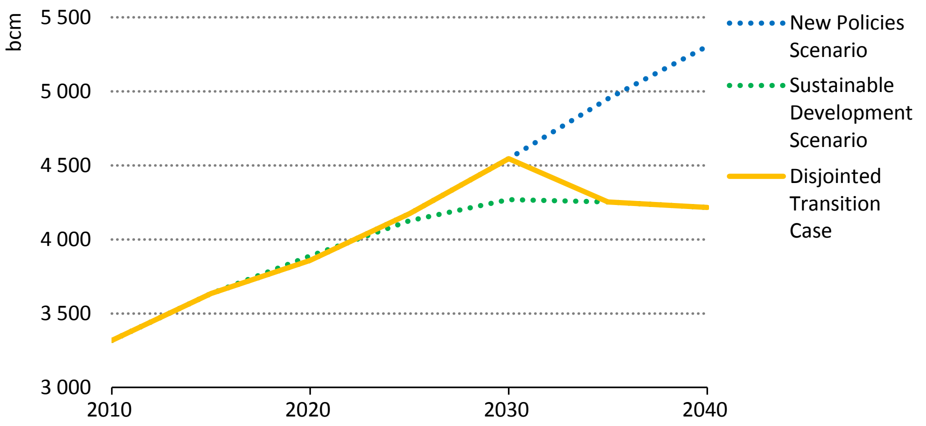
As discussed, the observed decline rate for conventional gas fields that have passed their peak is over 7% per year and the decline rate for unconventional gas production is much steeper. Global gas demand in the Sustainable Development Scenario remains broadly constant throughout the 2030s: if gas production is to meet this demand, declining fields therefore have to be offset by developing new reserves and by discovering and developing new resources. The prices and investment levels in the Sustainable Development Scenario are designed to ensure that sufficient new projects are brought online to balance supply and demand while ensuring all generate an adequate return. When governments pursue unambiguous policies to decarbonise the energy system, as set out in the Sustainable Development Scenario, there is unlikely to be widespread stranding of upstream natural gas assets: the same is true for LNG and pipeline assets.

For the power sector, there are some stranded gas power plant assets. However this is limited because operators of natural gas generating capacity receive revenue for maintaining generating capacity in the Sustainable Development Scenario. We estimate that cumulative stranded capital in gas-fired power generation capacity amounts to just under $7 billion to 2040, which can be compared with the $1 trillion invested in gas power plants to 2040 in the Sustainable Development Scenario. Advanced economies see the majority of stranded gas-fired power plant assets because they tend to seek deeper emissions reductions in the power sector sooner than in developing economies.

7. Stranded assets are defined as capital investment in fossil-fuel infrastructure that ends up failing to be recovered over the operating lifetime of the asset because of reduced demand or lower prices resulting from climate policy.

While there is only a limited stranding of assets in the Sustainable Development Scenario, in reality it can be difficult for investments to anticipate future policies and market developments, and supply can get out of line with demand levels, leading to price volatility. If a sudden change in policies were to bring about an abrupt and unexpected shift in demand, there is a risk that some investments may fail to recover the capital spent on them, since many assets in the energy sector have long lead times and lifetimes. We constructed a "Disjointed Transition Case" for oil markets in the *WEO-2016* to explore the impact of an unforeseen abrupt policy change on investments, based on oil demand following the New Policies Scenario but then dropping sharply to the level of the 450 Scenario.[8] This was found to lead to large financial losses for the upstream oil industry: the later the delay in the transition to a trajectory consistent with the Paris Agreement, the bigger the losses. A similar "Disjointed Transition Case" for gas markets would see demand (including LNG and pipeline imports) following the New Policies Scenario up until 2030, then transitioning suddenly over a five-year period to the demand trajectory in the Sustainable Development Scenario (Figure 11.18). The impact of a disjointed transition on gas markets, however, is not as clear-cut as it is for oil.

Figure 11.18 ▷ Global gas demand in a "Disjointed Transition Case"



A disjointed transition would not materially impact stranded upstream assets as the decline in demand is less than the observed decline in producing fields

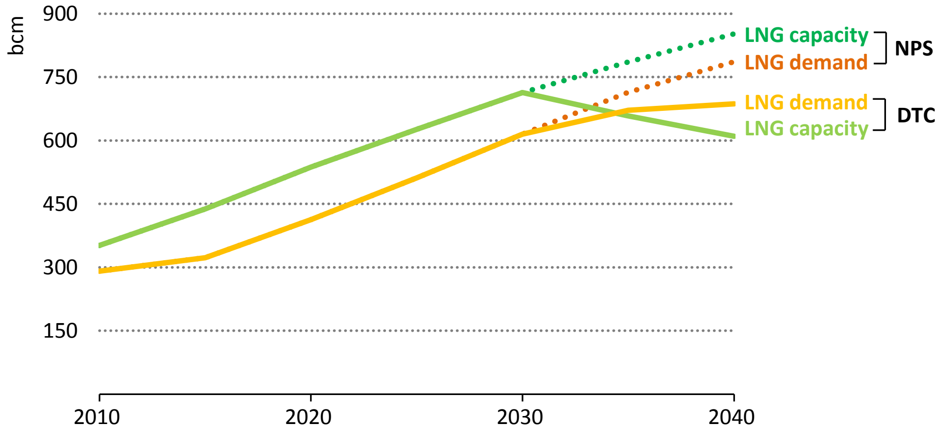
For gas production, the switch to the Sustainable Development Scenario under the Disjointed Transition Case would bring about a reduction of nearly 300 bcm in gas consumption in the space of five years. However, this impact is less severe than was the case for oil: in a Disjointed Transition Case global gas demand would decline by around 1.3% each year over the five-year period between 2030 and 2035 compared with a near 5% annual drop in oil demand over the same period. Indeed, the decrease in gas demand would still be much

8. The 450 Scenario modelled in the *WEO-2016* aimed to limit the temperature rise in 2100 to below 2 °C.

less than the observed decline in producing fields. As a result, there would still need to be investments in new sources of production to offset underlying declines, even during the five-year adjustment period, which would limit the risk of stranded upstream natural gas assets.

For LNG, capacity grows by over 270 bcm between 2016 and 2030 following the trend in the New Policies Scenario. There is, however, not nearly as large a shock to LNG demand from 2030 with the shift to the Sustainable Development Scenario as there is to overall gas demand. Overall LNG exports continue to rise even with the sudden shift to the trend in the Sustainable Development Scenario (Figure 11.19). Indeed, if no new capacity were to be built after 2030, global LNG capacity in the Disjointed Transition Case would be gradually eroded over subsequent years as facilities reached the end of their technical lifetimes and were taken out of operation, which would increase the utilisation of remaining facilities. Global liquefaction capacity in the Disjointed Transition Case in 2040 would be around 610 bcm, lower than the level of LNG exports. No export facilities would need to be closed prematurely and all facilities that exist in 2040 would be needed (indeed new facilities would need to be built): the risk of stranded LNG export facilities therefore looks limited in this case.

Figure 11.19 ▷ Global liquefaction capacity and demand in the New Policies Scenario and the "Disjointed Transition Case"



LNG demand continues to rise even in a disjointed transition and older facilities reaching the end of their technical lifetimes would limit the level of stranded export terminals

Note: NPS = New Policies Scenario; DTC = Disjointed Transition Case.

For pipeline assets, following the trend in the New Policies Scenario, around 180 bcm new pipeline capacity would be built in the Disjointed Transition Case between 2016 and 2030. Around one-third of this is to transport gas to China from Russia and the Caspian region. Since gas demand in China is higher in the Sustainable Development Scenario than in the New

Policies Scenario, all of this new pipeline capacity continues to be used in our projections to 2040, even after the transition to the Sustainable Development Scenario in 2030. In fact, more pipeline capacity would need to be built after 2025 to satisfy the continued increase in China's gas demand. However, pipelines built over the next fifteen years to export gas to more mature regions would be at much more risk. For example, between 2016 and 2030 some 75 bcm new pipeline capacity would be built in the Disjointed Transition Case in order to bring gas to European markets. Between 2030 and 2035, however, European gas demand would drop by nearly 100 bcm, and it would decline by a further 50 bcm over the subsequent five years. Much of the new pipeline capacity would not be required and there is a risk that some assets could become stranded.

11.6 Decarbonising gas supply

Significant and rapid progress in eliminating methane emissions from the production, transmission and distribution of natural gas is a vital component of the energy sector transition envisaged in the Sustainable Development Scenario. As discussed in Chapter 10, methane emissions from the natural gas value chain are 70% lower in 2040 than today's levels in the Sustainable Development Scenario. Failure to tackle these emissions comprehensively would not only reduce the climate advantages offered by natural gas compared with other fuels, but also reduce the remaining emissions space commensurate with achieving the objectives of Paris Agreement.

In regions where natural gas consumption declines in the Sustainable Development Scenario, the utilisation of existing infrastructure drops and this poses challenges for network operators and owners. For natural gas to become a zero-carbon fuel itself, CCS is essential (Box 11.3). There are, however, alternative options to make use of this infrastructure and that could lower the emissions intensity of the gas delivered and so aid in the energy sector transition. Two examples are bio-methane and hydrogen.

Biogas is a mixture of methane (CH_4), CO_2 and small quantities of other gases produced either through the gasification of biomass or by the anaerobic digestion of organic matter by bacteria and enzymes in an oxygen-free environment. Biogas can either be used directly, close to where it is produced, or be upgraded to remove the CO_2 (and other contaminants) to yield a pure stream of bio-methane. Bio-methane can be transported in a similar way to natural gas. Just over 60 bcm of biogas was produced globally in 2015, the majority of which was used in electricity and heat plants. One option for the future is to blend bio-methane with natural gas, which helps reduce the overall CO_2 intensity of the gas stream and could help prolong the utilisation of existing natural gas infrastructure in a low-emissions future: a number of countries already permit bio-methane injection into the gas network. An alternative option would be to use a pure stream of bio-methane in gas-fired power plants that provide flexibility to the electricity grid.

The potential of biogas and bio-methane are critically dependent on the availability and cost of the required feedstocks: municipal waste, animal by-products and dedicated energy crops are all suitable options. However, the cost of producing bio-methane is estimated to range between $6/MBtu and $17/MBtu if using waste as a feedstock and between $20/MBtu and $50/MBtu if using dedicated energy crops (IRENA, 2017). While the lowest cost bio-methane from waste may be cost competitive with natural gas, it is unlikely to have a substantial effect on overall natural gas consumption. The production cost of bio-methane using energy crops in particular is likely to be prohibitive. Costs would need to come down materially for biogas and bio-methane to form a central part of a low-carbon energy system.

Hydrogen could play a role in the low-carbon transition in a variety of ways. At present the largest user of hydrogen in the energy sector is industry, where hydrogen is created by steam reformation of natural gas and consumed on-site in the manufacture of ammonia and methanol or in the refining sector. To be useful in the energy transition, however, hydrogen will need to be generated using low- or zero-carbon energy sources and is likely to need to be transported over longer distances.

One way to produce hydrogen is by using electricity, often referred to as power-to-gas. This is of particular interest in the context of variable renewables. As the capacity of variable renewables grows, so does the risk of mismatches between electricity generation and demand. If more electricity is generated than the system needs, then, unless it can be stored or used, some capacity has to be curtailed and electricity is "lost" as a result. In the Sustainable Development Scenario, one-third of the world's electricity is supplied by wind and solar PV in 2040, and as much as 8% of variable electricity generation could be lost because of curtailment in the United States, European Union and India, unless there is scope to store it or to make use of it. The curtailed electricity in these three regions could provide around 20 Mtoe of hydrogen, roughly 2% of their natural gas demand in 2040 in the Sustainable Development Scenario. However, this may be prohibitively expensive. While the costs of the electricity would be very low (since it would otherwise be lost), the capital costs of hydrogen-production facilities are high and facilities are unlikely to be economic if they can only operate intermittently. It may well be that it makes more sense to produce hydrogen using dedicated generation facilities (solar, wind, hydropower or nuclear).

The question of how to transport hydrogen to end-users is also important. One possibility is to inject hydrogen into the natural gas stream within existing pipelines. The low-pressure distribution network could probably cope with relatively high injection levels; indeed the distribution pipelines in many countries originally transported town gas, which was around 30-50% hydrogen (Melaina, Antonia and Penev, 2013). There could be more of a problem with the transmission gas network, however, as elevated concentrations of hydrogen can lead to pipeline corrosion. Nevertheless, with only minor modifications, the transmission network could cope with up to around 10% hydrogen blended into the natural gas stream (Altfeld and Pinchbeck, 2013). Perhaps the biggest problem is that the ability of end-users to consume a blend of hydrogen and natural gas is rather limited. Many existing natural gas turbines, for example, could only handle around 1% hydrogen injection for performance and safety reasons (although they may be capable of tolerating 5-15% injection with some modifications).

Considering these difficulties, we estimate that hydrogen injection could displace around 100 bcm of natural gas consumption across the global energy system in 2040, which could help to reduce CO_2 emissions from some difficult-to-decarbonise end-uses. For example, the need for very high temperatures in some industry branches mean these cannot easily switch from natural gas or coal to renewables and electricity: using a mixture of natural gas and hydrogen would lower the emissions intensity of the delivered heat.

Box 11.4 ▷ Can natural gas be a zero-carbon fuel?

For natural gas to play a major role in a fully decarbonised global energy system – the ultimate post-2040 aim of the Sustainable Development Scenario – it will be necessary in the long term for its consumption to result in almost no CO_2 emissions. The key technology for this is CCS. At present CCS faces a number of challenges, not least that it requires additional capital investment and reduces operational efficiency, but does not directly generate any extra revenue (although the captured CO_2 can sometimes be used for enhanced oil recovery, as in PetraNova in Texas [United States] and Boundary Dam in Saskatchewan [Canada]). At present, policy support is insufficient to overcome the cost and financing barriers that are inhibiting deployment. However, if CCS reaches the point where it can be commercially deployed, then natural gas could be used in a variety of ways:

- Gas-fired power plants equipped with CCS would result in near-zero CO_2 electricity as discussed above.
- To produce a dedicated supply of pure hydrogen: this could be used in chemical synthesis in industry or to help decarbonise large vehicles, such as for freight or maritime transport, where the potential for electricity may be constrained by the need for inordinately large batteries. Indeed, analysis has suggested that the cost of using hydrogen in trucks, including the cost of dedicated hydrogen infrastructure, could become comparable to that of plug-in hybrid trucks (IEA, 2017b). However, while the distribution network may be able to handle a pure stream of hydrogen, an entirely new transmission network along with new end-user equipment would likely be required, which would entail significant cost.
- To produce hydrogen-rich chemicals, such as ammonia, which are easier to store and transport than a stream of pure hydrogen gas. Ammonia is currently used in industry in the production of nitrogen fertilisers: there has also been some recent renewed interest in the possibilities offered by ammonia as an energy carrier and as a fuel (especially for stationary applications such as balancing variable renewables and in industrial facilities).

PART C
CHINA ENERGY OUTLOOK

PREFACE

Part C of this *WEO* (Chapters 12-15) continues the past practice of examining in depth the prospects of a country of particular significance to the global energy outlook. This year, for the first time since 2007, the spotlight falls on China.

Chapter 12 analyses China's rapidly changing economic and energy landscapes. It sets out the existing institutional and policy architecture, China's key energy demand and supply trends, the scale of its energy resources and its role in global energy markets. In addition, it contains a detailed focus on China's regions and provinces. The chapter concludes by explaining the analytical approach for the projections that follow.

Chapter 13 looks at the outlook for energy demand, discussing policies and projections in the end-use sectors as well as in power generation, drawing on the results of the New Policies Scenario.

Chapter 14 focuses on the supply side, covering the spectrum of coal, oil, natural gas, renewables and nuclear. It assesses the prospects for development of these resources, the investments required, as well as the outlook for international trade.

Chapter 15 considers some of the wider implications of China's energy choices. It analyses in turn a case in which the economic transition is slower than anticipated in our New Policies Scenario and a case in which the clean energy transition is faster. It concludes with a review of China's evolving influence on international energy markets and trends.

Chapter 12

Energy in China today

Where now for the world's energy giant?

Highlights

- China is changing. The economy is progressively moving away from reliance on heavy industry and towards domestic consumption, higher value-added manufacturing and services. Energy demand growth has slowed considerably in recent years, from an annual average of more than 8% between 2000 and 2010, to less than 3% per year since 2010. This reflects structural shifts in the economy as well as a strong policy focus on energy efficiency.

- In parallel, the dominance of coal and, to a degree, oil products in the structure of energy use is under challenge from more environmentally benign sources of energy. Coal use has fallen for three straight years since 2013. China is already the world's largest investor in renewables-based generation, a leader in energy efficiency policies, new technologies and other areas where energy is intersecting with the digital economy, and the world's largest market for electric vehicles.

- China's influence in global energy markets extends to all fuels and technologies. China is a pivotal country for global coal markets, accounting for around half of global production and consumption; it is the world's largest importer of oil, a rising force in global gas markets, the largest exporter of solar equipment and a leading player in almost all low-carbon technologies. Chinese companies have also become major investors in a wide range of energy projects abroad.

- There are major divergences among China's provinces and regions in economic and demographic trends, resource availability and energy use. Economic activity and energy demand are concentrated in the coastal eastern provinces, home to almost 35% of the population. Addressing regional disparities and improving infrastructure across the country is a major priority for the government.

- China's rapid economic rise over the past four decades has had significant effects on its environment and public health. The government has long recognised the extent of the problems and has imposed stringent policies to arrest the decline in air and water quality as well as to curb growth in greenhouse-gas emissions. This is another major priority for government action.

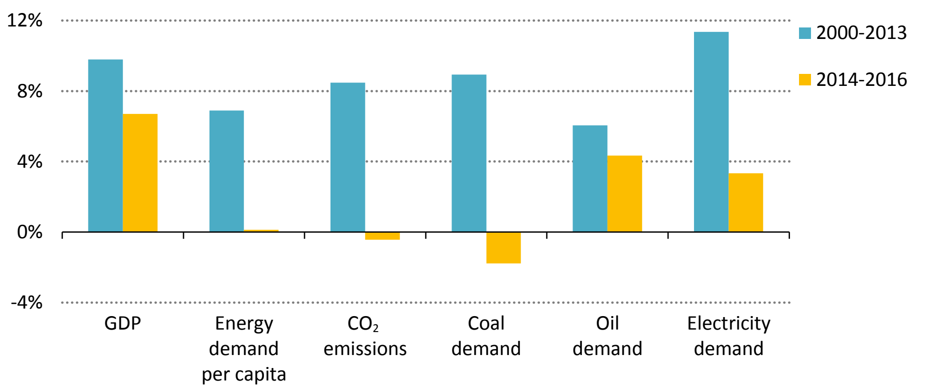
- The long-term goals of China's energy policies are defined by the president's call for an "energy revolution" in June 2014, which provides broad guidance for the energy five-year plans and other policies, as well as for the Energy Production and Consumption Revolution Strategy published in 2017. The overarching aim is to build a more secure, sustainable, diverse and efficient energy future.

12.1 Introducing the special focus on China

A special focus on the People's Republic of China (China) in the *World Energy Outlook – 2017 (WEO-2017)* should need no particular justification given the size of the country, the scale of its energy sector and its weight in global energy affairs. The huge changes in economic and energy policy underway in China at present are having an impact not just in the country and region but also in global energy markets: with 1.4 billion citizens and the second-largest economy in the world, what happens in energy in China matters.

For years, the dominant energy narrative on China concentrated on the extraordinary pace of its development, the country's success in lifting hundreds of millions of its citizens out of poverty – including energy poverty – and the voracious demand that this created for energy resources of all kinds, but primarily for coal and oil (Figure 12.1). Elements of this narrative remain valid today, and the energy infrastructure and environmental implications of this period of soaring growth will be with China for many decades to come. The country is changing course, however, and its new direction will have consequences that are no less significant for China and the world than the earlier period of energy-intensive development.

Figure 12.1 ▷ Comparisons in average annual growth rates for selected indicators in China, 2000-2013 versus 2014-2016

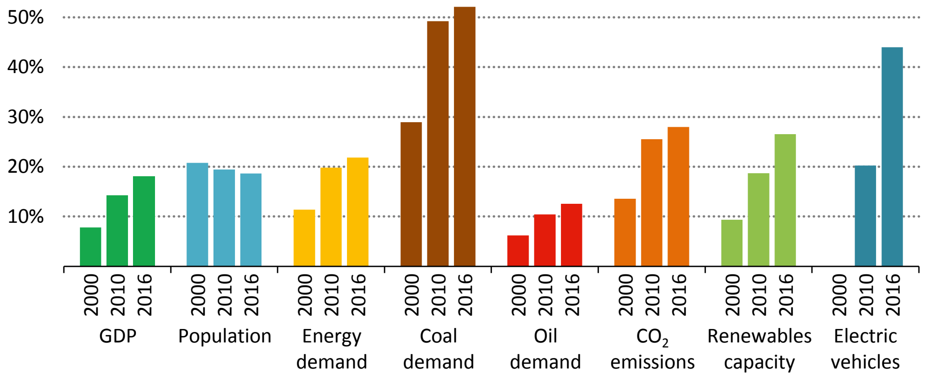


While the economy continued to grow strongly in 2014-2016, the implications for energy demand and CO_2 emissions were radically different than in previous years

Note: GDP = gross domestic product ($2016 billion, PPP).

The outlook for China depends on the outcome of a number of transitions that are underway, supported by policies aimed at securing a more sustainable model for China's future prosperity. The economy is starting to orientate away from a reliance on export-driven heavy industrial sectors towards domestic consumption, higher value-added manufacturing and services. In parallel, more environmentally benign sources of energy are challenging the dominance of coal and (to a degree) oil products in the structure of energy use. The first fruits of China's declaration of a new "energy revolution" in 2014 are already visible (Figure 12.2).

Figure 12.2 ▷ China's share of selected global indicators



China has an immense presence in global energy across a range of fuels and technologies

Note: GDP = gross domestic product ($2016 billion, PPP).

For this in-depth assessment of China's energy sector and its prospects to 2040, we have conducted an extensive review of existing policies, regulations and programmes affecting the energy sector, as well as announced intentions. In each sector, we assess China's record of achievement and examine what this may imply for the speed of future action. Table 12.5 contains a summary of China's domestic policy objectives taken into consideration in the New Policies Scenario.

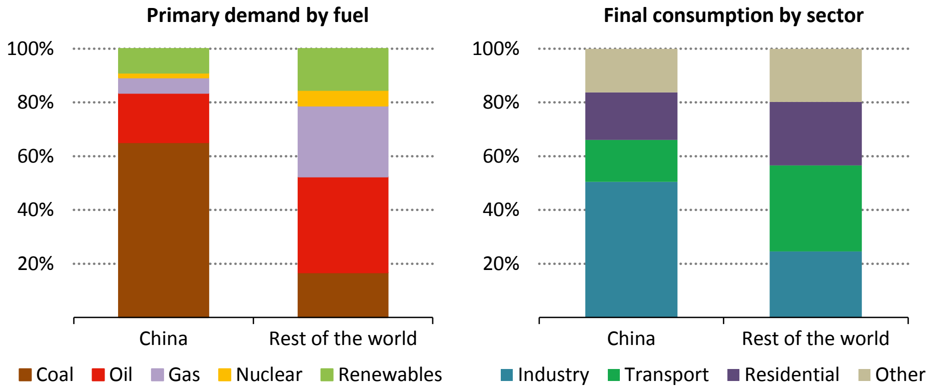
This report comes against a backdrop of a strong and growing partnership between China and the International Energy Agency (IEA), including a comprehensive three-year IEA/China Association agreement work programme, and with support from the newly created IEA-China liaison office in Beijing.[1] With major reforms underway, described in detail in the 13th Five-Year Plan, the aim of this special report is not to prescribe a path for China, but rather to provide a coherent framework in which China's own policy choices can be assessed. We consider their implications not only for the country's development, energy security and environment, but also for the integrated global energy system in which China plays a leading role.

1. This analysis has benefited greatly from regular discussions with Chinese officials, industry representatives and experts, notably during a high-level *WEO* workshop held in Beijing in February 2017, as well as from the input of Chinese colleagues seconded to the International Energy Agency.

12.2 Energy trends in China today

Coal largely fuelled the rapid industrial and economic growth that led to China becoming the world's largest energy consumer in 2009. Growth in demand for coal has averaged almost 7% each year since 2000: at the start of this period, China accounted for less than one-third of global coal demand, and its share is now more than half. Coal now accounts for almost two-thirds of China's primary energy demand, catering for much of the country's huge industrial demand for energy and providing the backbone of China's immense power system, which has accommodated a quadrupling in electricity demand since 2000. Despite the recent changes in momentum and direction, the starting point for our energy outlook is still an energy economy that, compared with the global average, has an atypical mix of primary fuels and a structure of consumption that is very heavily weighted towards industry (Figure 12.3).

Figure 12.3 ▹ Comparison of China's primary energy demand by fuel and final consumption by sector with the rest of the world average, 2016



The legacy of China's precipitous economic rise is a system heavily skewed towards coal and energy use in industry

Note: TPED = total primary energy demand; TFC = total final consumption; also see note with Table 12.1.

12.2.1 Energy demand

Between 2000 and 2016, total primary energy demand in China increased by more than 160%, at an annual average rate of 6%. This was lower than the average annual GDP growth of almost 10%, a divergence that brought a steady decline in energy intensity (Table 12.1). As noted, coal was responsible for the lion's share of this growth, but oil demand also rose sharply and China is now the largest oil-importing country in the world. The other major component of China's energy mix in 2000, after coal and oil products, was solid biomass, which was widely used for cooking and sometimes also for heating. One of the less recognised energy achievements of China over the last two decades has been a dramatic reduction in the population depending on solid biomass for energy. In the last 15 years, 260 million people have gained access to modern fuels as urbanisation, 100% electrification and the extension of liquefied petroleum gas and natural gas supply have made alternatives more accessible and attractive.

Table 12.1 ▷ Selected energy and economic indicators for China, 2000-2016

Indicator	2000	2005	2010	2016	Change 2000/16
GDP ($2016 billion, PPP)	5 278	8 318	14 023	21 721	312%
Share of world GDP	8%	10%	14%	18%	-
GDP per capita ($2016, PPP)	4 158	6 347	10 428	15 685	277%
Total primary energy demand (Mtoe)	1 143	1 794	2 551	3 006	163%
Primary energy demand/capita (toe)	0.90	1.37	1.90	2.17	141%
Total CO_2 emissions (Mt)	3 127	5 399	7 726	8 973	187%
Energy intensity TPED/GDP (toe per $1 000, PPP)	0.22	0.22	0.18	0.14	-36%
Carbon intensity TPED CO_2/GDP (tCO_2 per $1 000, PPP)	0.59	0.65	0.55	0.41	-30%

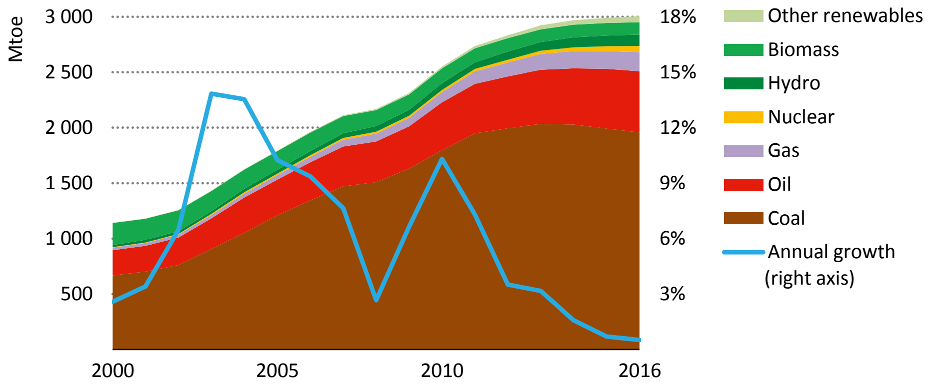
Note: GDP = gross domestic product; PPP = purchasing power parity; Mtoe = million tonnes of oil equivalent; toe = tonne of oil equivalent; Mt = million tonnes.

Notes on energy data: The national energy data used in this report are from IEA statistics and balances. These are taken or derived from China's National Bureau of Statistics (NBS), but differences in methodology mean that there are some variations between IEA and NBS data. These include the definition and method of calculating total primary energy demand (TPED); in some instances, projections of TPED calculated according to the NBS methodology are presented alongside the IEA number to aid comparison. All provincial and other sub-national data are sourced directly from the NBS and may not be entirely consistent with the national totals. The IEA, in close consultation with the NBS, regularly reviews and updates its China energy data to ensure it accurately incorporates China's latest published energy statistics.

Over the last decade, some new features have emerged more prominently in the primary energy mix, as China's policies have sought to move away from the strong reliance on coal, bring more diversity to its energy mix and tackle some burgeoning environmental issues, notably the deterioration in air quality (Figure 12.4). Natural gas has been a prime beneficiary of this policy drive, and its share in the energy mix has more than doubled over the last ten years, albeit from a base that was only a small fraction of the global average. China has built pipelines and liquefied natural gas (LNG) regasification terminals linking the country with new sources of gas (including a large-scale connection with resource-rich Turkmenistan and additional plans with Russia). The use of natural gas has increased among all energy end-use sectors in China, with the power generation and heat sectors accounting for a large part of the increase.

The impressive growth of low-carbon energy sources has been largely concentrated in the power sector, although China also accounts for more than 70% of the world solar thermal market. Generation from nuclear plants has increased ten-fold since 2000 and hydropower has increased five-fold, albeit both from relatively low bases. More recently, China has also led the world in expanding wind and solar energy: its renewables-based power capacity (including large-scale hydro) now exceeds that of the European Union and is more than double that of the United States.

Figure 12.4 ▷ Primary energy demand by fuel in China



Growth in energy demand has slowed, coal (probably) has peaked, developments suggest that China's energy future may look quite different from its past

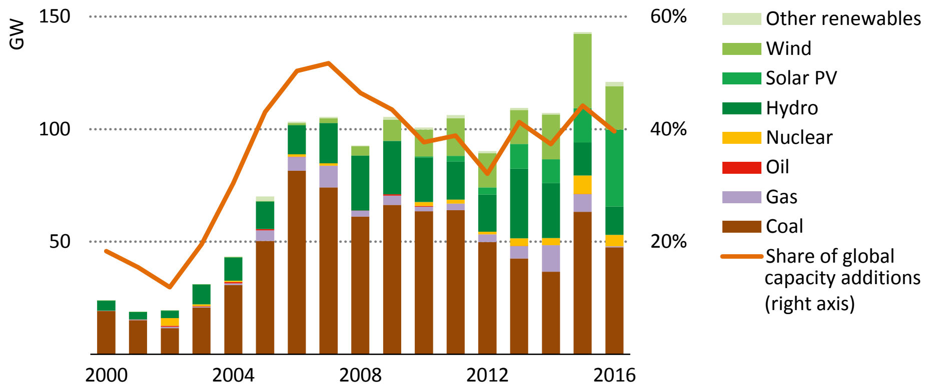
The rate of growth in energy demand has slowed significantly in recent years. Between 2000 and 2010, energy demand increased on average by 8.4% per year: since 2010, this figure has fallen to just below 3%, and since 2014, it has slowed still further. This reflects the start of major structural shifts in the economy, as well as China's position at the forefront of many aspects of energy efficiency regulation, particularly in the industrial sector: mandatory standards now cover more than 58% of China's final consumption, a figure well above global coverage of 32%.

As demand growth has slowed, especially in the heavier industrial sectors, and as new sources of supply have entered the picture, some potential inflection points in China's energy trends have started to be visible. Coal consumption has fallen for three straight years since 2013 and – barring an exceptionally dry hydro year or some other event that might lead to a spike in coal demand – is increasingly unlikely to regain its former heights. Furthermore, China's energy-related carbon dioxide (CO_2) emissions declined in 2016, after 15 years of more than 7% annual growth.

Power sector

China has the largest installed power generation capacity in the world by a wide margin – it is 40% higher than that of the United States, which has the second-largest system in the world. Nearly 60% of its more than 1 600 gigawatts (GW) of installed capacity is coal-fired. Although the direction is unmistakeable, with coal's share of total capacity having fallen by ten percentage points since 2010, the shift away from coal is likely to be gradual. China's fleet of coal-fired power plants is relatively young: more than half of it is less than ten years old. It is also relatively efficient: much of the plant built in the past decade is supercritical (24%) or ultra-supercritical (20%), operating at much higher efficiencies. As a result, the average efficiency of coal-fired generation in China has increased from 32% in 2000 to 37% today (excluding CHP). Much of it is also equipped with advanced air pollution controls to comply with an emissions standard that was introduced in 2012 in order to cut local pollutants. New ultra-low emission standards that will be phased in between 2017 and 2020 are set to bring further investment in pollution controls.

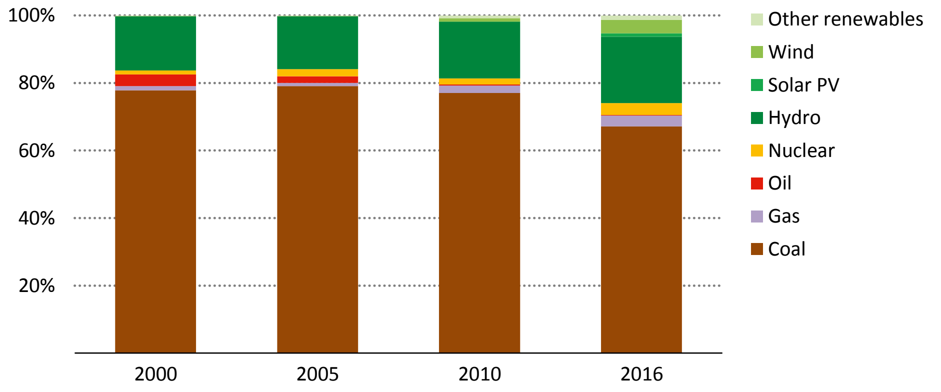
Figure 12.5 ▷ Annual power generation capacity additions by type in China



Since 2013, the majority of capacity additions to China's power system have come from wind, solar PV, hydropower and nuclear

China accounted for over two-fifths of global electricity capacity additions in the past decade, with an average of 108 GW installed each year (Figure 12.5). Since 2013, more than half of these additions have been in renewables and (to a lesser extent) in nuclear power. In terms of renewables, China ranks first in the world in installed capacity of hydropower, wind and solar photovoltaic (PV) power. The switch towards renewables in new power investment decisions has boosted their share in China's capacity to more than one-third, from less than a quarter ten years ago. Wind power, which now accounts for almost 10% of China's total capacity, has edged past nuclear and natural gas to become China's third-largest source of power supply (after coal and hydropower). Solar PV has experienced very strong growth, with installed capacity increasing by more than 75 GW between 2010 and 2016. China is among the world's leaders in nuclear power generation, with capacity increasing from 2.3 GW in 2000 to 33.6 GW in 2016: almost half of global nuclear capacity under construction today is in China.

Figure 12.6 ▷ Power generation mix in China



Coal and hydropower dominate the power generation mix, but a broader diversity has emerged since 2010

The large expansion in capacity, especially in the last few years, has coincided with a period of slowing electricity demand growth, which has dropped from 12% per year in the decade to 2010 to just over 6% a year since then. As a result, China has found itself with excess coal-fired capacity, which has pushed down utilisation rates: this coincided in 2016 with a rise in coal prices, which made a further dent in the margins of these plants. At the same time, the rise in variable renewables, wind power in particular, has shone a spotlight on the limited flexibility of China's power system (despite its high share of hydropower): as much as 17% of wind power generation was curtailed in 2016 because the system was unable to accommodate it. In these circumstances, China's continued strong support for low-carbon generation, including new measures that would allow renewable generators to participate in markets without the use of feed-in tariffs, has inevitably meant looking at broader questions of power sector reform (examined in detail in Chapter 13).

End-use sectors

The pattern of end-use energy consumption in China across the main sectors (industry, transport, buildings and agriculture) shows continued dominance of industry, which makes it an outlier compared with global averages. Industrial demand drove 60% of the growth in final consumption which has taken place since 2000, largely because of a rise in energy demand for manufacturing steel, cement, chemicals and other energy-intensive products. Today China's industrial sector accounts for more than half of total final energy consumption (Figure 12.8). Energy for transport and the buildings sector lag far behind.[2] This has significant implications for the structure of energy expenditure in China (Spotlight).

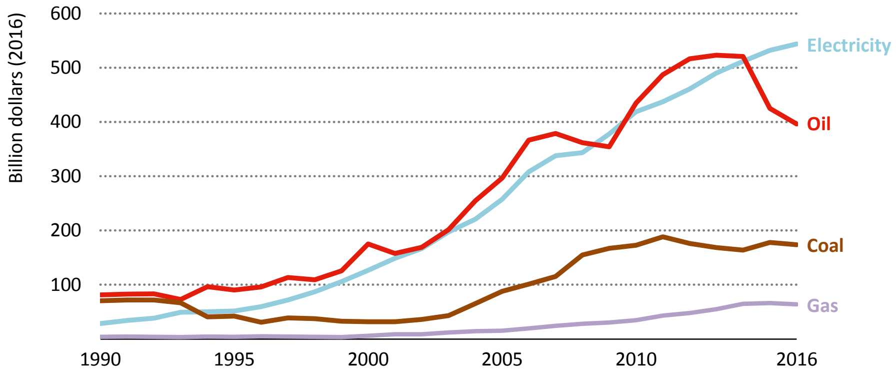
2. The buildings sector includes energy used in residential, commercial and institutional buildings.

S P O T L I G H T

A trillion dollar question: what are China's energy consumers spending their money on?

Oil products dominate end-user expenditure on energy in most major developed and developing economies. This is not the case in China, however, where a much lower (though still very significant) level of expenditure on oil means that electricity accounts for the largest share of expenditure (Figure 12.7).

Figure 12.7 ▷ Historical end-user energy expenditure in China



The prominence of electricity in China's end-user energy expenditure contrasts with a global picture in which oil products take the largest share

Some distinctive aspects of China's economic structure and energy sector explain the relatively low share of expenditure on oil compared to other major economies, and the implications that has for China's pattern of end-use energy expenditure.

- A key point is that, although a structural transition is underway, industry still dominates China's energy use, and coal still dominates industry's energy use. The effect is to push up the overall share of coal in China's total final consumption (35% compared with an average in the rest of world of less than 5%) and to push down considerably the share of oil (26% in China versus more than 40% in the rest of the world).
- The dominance of industry in terms of energy use also has a huge impact on the overall pattern of energy expenditure in China, which is very different from that in advanced economies where for every dollar spent by industry on energy, households spend $2 (residential and passenger vehicle expenditure, including oil for transport). This relationship is reversed in China: for every dollar spent by a Chinese household on energy, over $3 is spent by industry.
- Because of the dominance of coal, the share of oil in China's industrial energy mix is half the global average. China has a slightly higher share of electricity in the

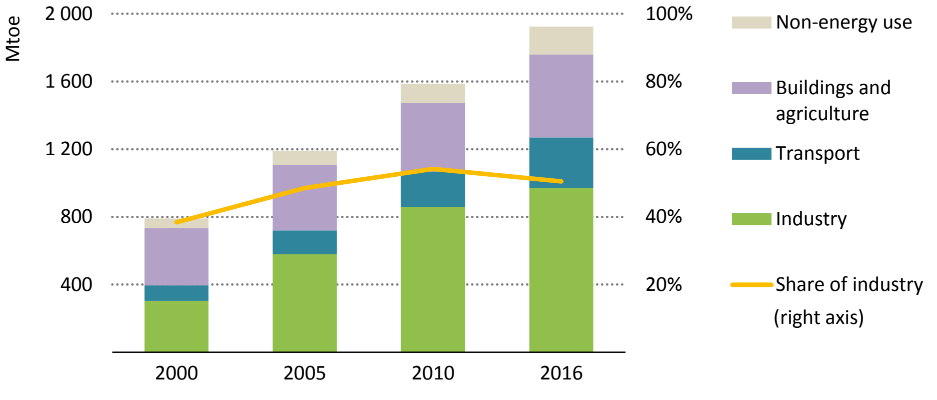
12

energy mix than the global average (some 3% above the global average of 26%). The result is that the ratio of oil consumption to electricity consumption in China is very different from the rest of the world: China consumes nearly twice as much electricity as the rest of the world for every barrel of oil consumed.

- Although there has been a large measure of liberalisation, subsidies remain in place for oil consumption in China. This does not necessarily render oil more attractive but it results in lower expenditure on oil. On the other hand, electricity prices in China are actually quite high by comparison to countries such as the United States.

From this starting point, adjustments to China's consumption patterns to bring them towards today's global average would imply a major upswing in oil demand (primarily at the expense of coal). This could see oil-based expenditure overtake electricity – especially if oil prices were to rise from their current levels. There is another possibility, however, which is that China pursues a path leading to much broader electrification of end-uses, including in the traditional stronghold of oil use in transport, alongside a parallel decarbonisation of electricity supply. Under these circumstances, the dominance of electricity in end-use expenditure could be maintained, and even strengthened, establishing a distinctive pattern of energy use.

Figure 12.8 ▷ Total final energy consumption by sector in China



Energy-intensive branches of industry led the rise in China's final energy consumption, but other sectors are set to take over as sources of future growth

There are clear signs of a shift in patterns of end-use consumption, as steel and cement production in particular falls and growth shifts towards technological innovation, consumer spending and services. Over the last five years, industrial energy demand growth has slowed to an annual average of 1.4%, while in the transport and services sectors both have annual average increases of 4.6%. While overall oil demand continues to show robust growth in transport, signs of a broader economic adjustment are also visible. Demand for diesel, used primarily for freight and therefore correlated with industrial activity, fell in 2016. By contrast, gasoline demand continued its rapid rise, primarily for private passenger cars: gasoline-fuelled vehicle sales grew at 16% year-on-year in 2016. Also in 2016, China saw sales of almost 350 000 electric passenger vehicles and more than 35 000 electric buses, underlining its position as the world's largest market for electric vehicles.

12.2.2 Focus on energy in China's regions and provinces

Unsurprisingly for a country the size of China, there are major divergences in economic and demographic trends, resource availability and energy use across the country. These have a major impact in shaping national and provincial policies, as well as infrastructure development. For the purposes of this part of the *Outlook*, we consider four main regions, which correspond to the four economic zones that are used for planning and statistical purposes in China:

- **East:** including the affluent coastal provinces of Beijing, Tianjin, Hebei, Shanghai, Jiangsu, Zhejiang, Fujian, Shandong, Guangdong and Hainan.
- **Central:** including Shanxi, Anhui, Jiangxi, Henan, Hubei and Hunan provinces.
- **West**: including the vast inland reaches which are generally poorer and more sparsely populated, though it also includes the industrial centres of Sichuan and Chongqing, and the provinces of Inner Mongolia, Guangxi, Guizhou, Yunnan, Tibet, Shaanxi, Gansu, Qinghai, Ningxia and Xinjiang.
- **Northeast**: including the three traditional industrial provinces Liaoning, Jilin and Heilongjiang.

Overall, two-thirds of China's population lives in East and Central China (four of the five most populated provinces, Guangdong, Henan, Jiangsu and Shandong are located within these two regions). One way of illustrating the uneven distribution of population is to take the notional Heihe-Tengchong Line, running from Heihe in the north to Tengchong in the south, which divides the country in two parts (Figure 12.9). The area west of this line (some 60% of the total area of China) contains only 6% of the population. The smaller area to the east (some 40% of the total area of China) is home to 94% of the population.

The vast bulk of all economic activity also occurs in the area to the east of the Heihe-Tengchong Line, which is responsible for more than half of the national GDP. The most developed provinces such as Guangdong, Jiangsu, Shandong and Zhejiang are all located in the coastal area. The inland provinces, by contrast, have fallen behind the prosperous regions closer to the coast, prompting a range of government actions to address these disparities. Each region has an overall regional strategy: the "go west" strategy for the West; the "revitalisation of the old industrial base" for the Northeast; the "rise of the Central region"; and the "leading development" for the East. The central government provides fiscal transfers to poorer provinces: almost a third of the provinces get more than half their financial resources from central government.

Figure 12.9 ▷ China's provinces by population density and main regions in 2015

The map presents data of provinces in China.
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

In energy terms, each region has its distinctive profile (Table 12.2, Figure 12.10). The geographical location of energy demand is broadly consistent with the distribution of population and GDP. Industrial coastal provinces in the East – notably Shandong, Hebei and Jiangsu – tend to have the highest energy demand, much higher than in western parts of the country, although eastern provinces with a concentration of services or higher value manufacturing (such as Shanghai) have higher GDP without the same impact on energy consumption. Considered by sector, industry takes the largest share of final consumption in almost all regions with the exception of Beijing, where energy use in buildings is the largest energy-consuming sector. Energy use in transport also correlates with GDP, and is highest in the East and in some Central provinces.

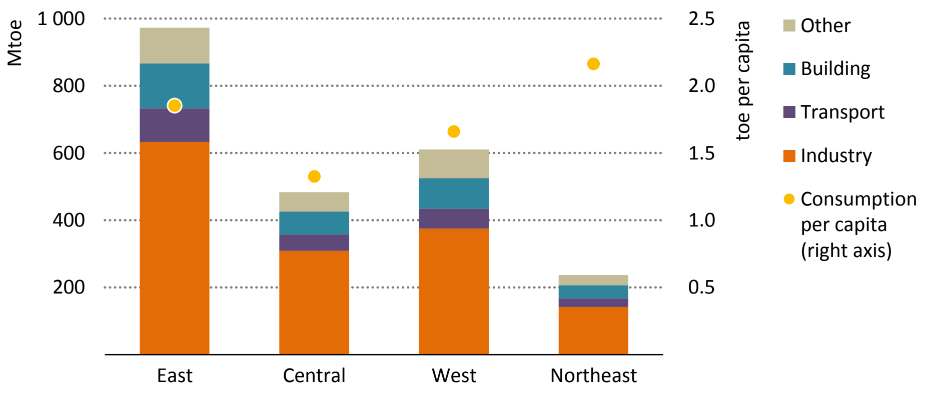
Table 12.2 ▷ Selected indicators for population, GDP, energy use and trade by region and province in China, 2015

Region / province	Population (million)	GDP ($ billion)	GDP per capita ($)	Electricity demand per capita (kWh)	TFC (Mtoe)	Energy surplus (+) / deficit (-) (Mtoe)
East	**525.2**	**5 988**	**11 402**	**5 247**	**973**	**-668**
Beijing	21.7	370	17 020	4 388	36	-30
Tianjin	15.5	266	17 164	5 175	46	2
Hebei	74.3	479	6 445	4 277	173	-137
Shanghai	24.2	403	16 703	5 820	66	-48
Jiangsu	79.8	1 126	14 114	6 413	153	-162
Zhejiang	55.4	689	12 431	6 416	96	-84
Fujian	38.4	417	10 865	4 824	59	-22
Shandong	98.5	1 012	10 273	5 197	188	-73
Guangdong	108.5	1 169	10 776	4 895	145	-114
Hainan	9.1	59	6 526	2 990	11	0
Central	**364.9**	**2 359**	**6 466**	**2 866**	**484**	**9**
Shanxi	36.6	205	5 594	4 741	89	308
Anhui	61.4	353	5 751	2 669	68	-31
Jiangxi	45.7	269	5 881	2 381	47	-35
Henan	94.8	594	6 267	3 038	112	-84
Hubei	58.5	474	8 107	2 845	88	-82
Hunan	67.8	464	6 841	2 134	79	-66
West	**371.3**	**2 328**	**6 270**	**4 151**	**611**	**537**
Inner Mongolia	25.1	286	11 402	10 127	96	318
Guangxi	48.0	270	5 625	2 782	53	-33
Chongqing	30.2	252	8 364	2 901	47	-26
Sichuan	82.0	483	5 881	2 429	105	-38
Guizhou	35.3	169	4 777	3 326	50	25
Yunnan	47.4	219	4 611	3 034	51	-15
Tibet	3.2	16	5 086	1 251	*n/a*	*n/a*
Shaanxi	37.9	289	7 629	3 221	59	253
Gansu	26.0	109	4 193	4 226	37	-13
Qinghai	5.9	39	6 600	11 190	18	-4
Ningxia	6.7	47	6 998	13 149	26	-5
Xinjiang	23.6	150	6 344	9 154	71	77
Northeast	**109.5**	**928**	**8 480**	**3 203**	**237**	**-132**
Liaoning	43.8	460	10 504	4 530	123	-94
Jilin	27.5	226	8 202	2 368	49	-43
Heilongjiang	38.1	242	6 353	2 280	64	6

Note: Mtoe = million tonnes of oil equivalent; kWh = kilowatt-hour; TFC = total final consumption.

Source: China's National Bureau of Statistics (NBS).

Figure 12.10 ▷ **Total final energy consumption by sector in China, 2015**



Industry is the largest energy-consuming sector in almost all provinces across China, with the exception of Beijing

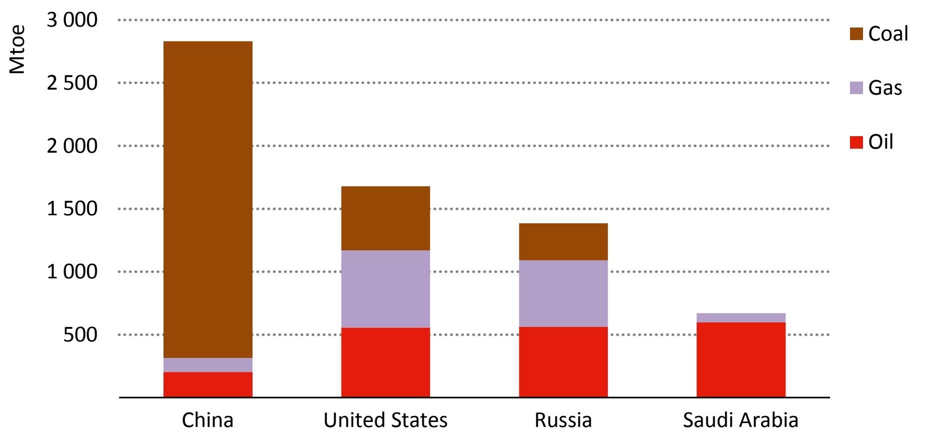
The structure of energy demand by fuel also varies significantly among the regions. The share of coal in energy demand is highest in the Central region, while the eastern provinces tend to have a higher share of oil and electricity in total final consumption. Natural gas consumption is concentrated in areas with indigenous production (around the Sichuan basin in the West) or in parts of country well served by imports, via pipeline (e.g. Xinjiang) or LNG along the coast (e.g. Guangdong).

Matching China's resources, production and demand

China is, by some distance, the largest global producer of fossil fuels. The country's oil output has been in decline in recent years, but at 4 million barrels per day (mb/d) in 2016, it remains the world's seventh-largest producer. Natural gas output of 137 billion cubic metres (bcm) in 2016 is significant, enough to put it in the top-six producers globally, albeit a long way behind the global gas powerhouses of the United States and Russia. However, it is China's vast coal production that makes it the world's largest producer of fossil fuels (Figure 12.11).

Coal production is scattered across China with almost every province having a number of mining operations. However, output is highly concentrated, with three provinces – Inner Mongolia, Shaanxi and Shanxi – accounting for over 60% of domestic coal production. These provinces are all located in the West and Central regions, relatively far from the major demand centres along the coast (Figure 12.12). Moreover, one of China's most promising future prospects for low-cost coal is in Xinjiang in the west, even further away from today's centres of coal demand. This geographical mismatch of supply and demand implies massive amounts of coal need to be hauled over thousands of kilometres (km) from producers to consumers. Railways and coastal shipping (and typically a combination of the two) do most of the heavy lifting, although truck transport for short distances is also common.

Figure 12.11 ▷ **Total fossil-fuel production in selected countries, 2016**



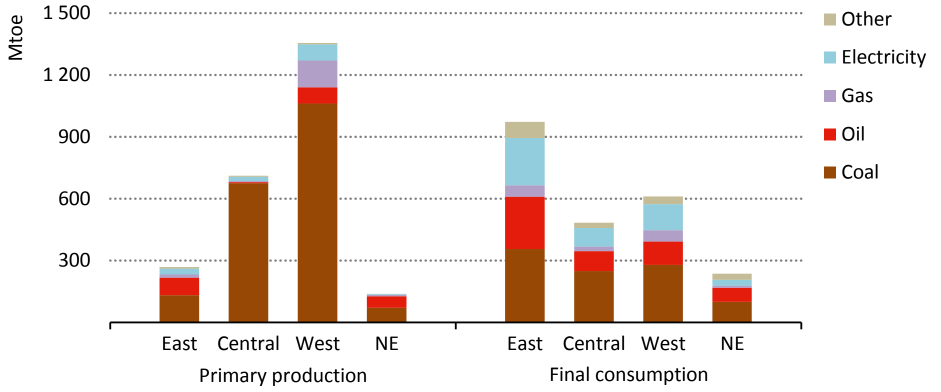
Coal production makes China, by far, the largest global producer of fossil fuels

Railways transported some 2 billion tonnes of coal in 2015 (coal has long been the primary cargo handled by China's railways, accounting for some 60% of total tonnage). Several large railway corridors link the coalfields in Shanxi, Shaanxi and Inner Mongolia with loading ports in the northern provinces of Hebei, Tianjin, Liaoning and Shandong, with the biggest and most important port in Qinhuangdao. The distance between the mines and the ports varies but broadly falls into a range of 600 km to 1 000 km. Ships then distribute the coal along the coastal rim from Jiangsu to Guangxi, where there is competition with imported coal. Transport is a critical cost component: getting coal from Inner Mongolia or Shanxi to Guangdong can easily add around $25 per tonne to the delivered cost. One option to reduce coal transport is to develop coal-fired power plants near the coalmines and transmit electricity with high-voltage direct current lines to demand centres.

China's oil production is slightly less concentrated than is the case for coal. The Daqing oilfield in Heilongjiang province (Northeast region) is the largest oil-producing complex in the country. The Shengli oil field is another major production centre, located in Shandong province (East region). Both Daqing and Shengli are mature areas where production began in the 1960s; as such, they both face challenges with high decline rates and water cuts (i.e. ratio of water to produced hydrocarbons). Most production in the West is in Shaanxi and Xinjiang provinces. Production of natural gas is largely in the West: in Sichuan (the traditional centre of the domestic gas industry), Shaanxi and Xinjiang.

Among the renewable sources of energy, four provinces (Yunnan, Sichuan, Guizhou and Guangxi, in the West region) produce nearly 60% of all hydropower output, (although the Three Gorges dam – the largest in the world – is in Hubei province in the Central region). The centre of China's solar industry – and therefore of the world's solar industry – is the Yangtze River Delta, an area that includes Shanghai and parts of two provinces to its west. Solar and wind power installations tend to be concentrated in the West region in provinces such as Gansu and Xinjiang.

Figure 12.12 ▷ Primary energy production and total final energy consumption by fuel and region in China, 2015



A major infrastructure challenge for China is to bring primary energy from provinces in the west to the major consumption areas near the coast

Note: NE = Northeast.

12.2.3 China and global energy markets

China is the world's largest producer of fossil fuels, but its output still falls short of the country's demand for coal, oil and gas. As a result, it is also the world's largest importer of fossil fuels. China's importance in global energy markets extends well beyond its role as a producer and importer of fossil fuels; it is also a major investor in energy projects and infrastructure in many parts of the world, particularly in developing countries (Box 12.1). In addition, China is an increasingly important developer and exporter of energy technologies, including many clean energy technologies. As a result, China's energy policy choices have implications that stretch well beyond its borders – and beyond the energy sector.

Box 12.1 ▷ Chinese energy investments abroad

Initially as part of the government's "Going Abroad" strategy, and since 2013 in the context of the Belt and Road Initiative[3], the activity of Chinese-owned energy companies abroad has become a major and important element of international flows of investment and technology. The drive for international investment has been underpinned in part by a strategic desire to strengthen regional connectivity and to build new supply

3. The vision of the Belt and Road Initiative extends well beyond energy, and encompasses the creation of a network of railways, roads, pipelines, maritime routes, ports and utility networks that link China with Central Asia, the Caucuses, the Middle East, and eventually Southern and Central Europe (and even as far as Africa and South America). The "Belt" aspect relates mainly to overland routes while the "Road" is to enhance maritime interconnectivity.

chains, given China's growing dependence on imported energy resources. Commercial factors are also at play, including the search for markets against a backdrop of domestic overcapacity and the desire to foster new capabilities and technical expertise. The initiative enjoys considerable political support, which was underlined by a high-level international forum held in Beijing in early 2017.

As a result, major Chinese energy companies have established a global footprint over the last decade. In the oil and gas sector, Chinese national oil companies increased their overseas equity production to an estimated 3 mb/d in 2016 (IEA, 2017). Thanks to mergers, acquisitions and participation in various consortia, Chinese companies are an established presence in all the major upstream markets and have emerged in some instances as a preferred partner for resource-rich countries because of the access that they provide to the growing Chinese market. They have further expanded their supply chains by investing in pipelines, storage facilities, refineries and sales and trading capacity. The desire to secure assets took them into some high-risk countries, for example South Sudan, where geopolitical and security challenges have entailed heavy reliance on diplomatic support from the Chinese government.

Africa has been a particular focus for Chinese companies and their involvement has gone well beyond oil and gas. In sub-Saharan Africa, Chinese companies operating as the main contractor for power generation projects were responsible for 30% of new capacity additions in 2010-15. Chinese investors are active in all fuels, natural gas, coal, renewables with a particular focus on hydropower projects and across the supply chains, including projects for cross-border transmission lines, and local urban and rural distribution networks.

In many parts of Asia, notably in Southeast Asia, China has emerged as a major financier of coal and hydropower projects. While exact financial figures are difficult to obtain, the number and size of planned power plants built or financed by Chinese enterprises suggest that the scale of Chinese projects in Southeast Asia's power sector is significant. It extends to Latin America as well: the State Grid Corporation of China (SGCC), the world's biggest utility company, has become the largest power generation and distribution company in Brazil.

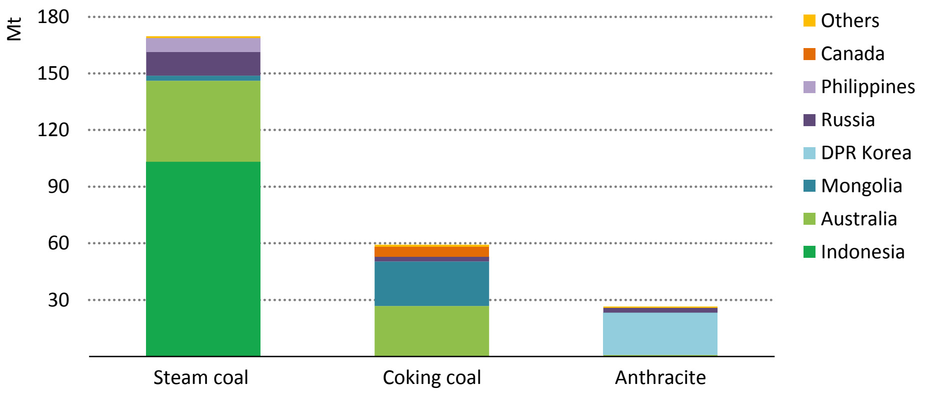
The Chinese government established a $40 billion Silk Road Fund in 2014 to finance investments in a number of key projects. Lending from Chinese development banks has also been the predominant source of finance, and the China-backed Asian Infrastructure Investment Bank, a multilateral institution, has a mandate that also allows it to provide funding for some related projects.

Coal

China is a pivotal country for global coal markets and its role has evolved dramatically in recent years. In 2007, China exported more than 50 million tonnes (Mt) of coal, mainly to Japan and Korea, but in 2009, it switched to becoming a net importer as domestic coal demand expanded considerably. In its first year as a net importer, China became the second-largest coal importer in the world, after Japan. In 2011, China overtook Japan to become the world's largest coal importer. In 2013, coal imports reached over 300 Mt, the largest amount of coal ever imported in one year by any country. That was a turning point: since 2013, coal demand has declined, leaving the domestic coal market structurally oversupplied and dampening import volumes.

The level of future coal imports depends in large part on policies to limit China's output and restructure the industry (see Chapter 14). The arena for competition between domestic and imported coal is in the southern coastal provinces: a substantial amount of coal is shipped from China's northern ports (nearer the production centres) to its southern ports (consumption centres) to meet demand and those southern ports are also where imported coal arrives. Approximately 900 Mt of coking coal and steam coal combined arrived by sea at the coastal region in 2016. Around 600 Mt of this volume was shipped from domestic sources and the remainder was imported, mainly from Indonesia and Australia (Figure 12.13). Anthracite imports in 2016 came mostly from the Democratic People's Republic of Korea (DPR Korea) (22.5 Mt), though such imports were suspended in early 2017.

Figure 12.13 ▷ Chinese coal imports by source, 2016



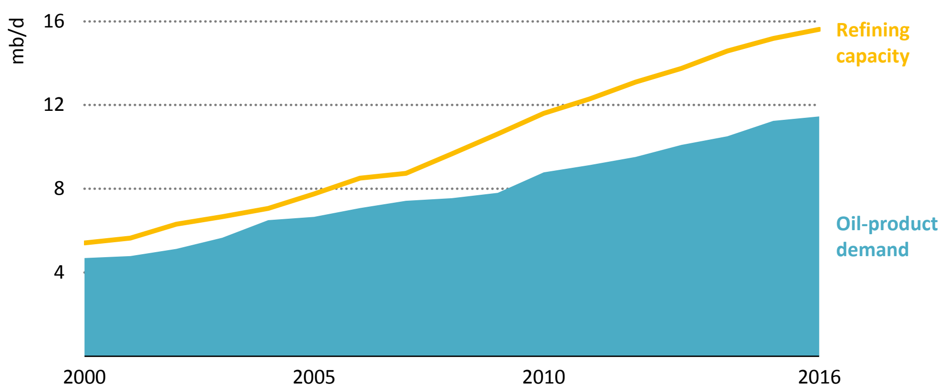
Indonesia and Australia account for the bulk of China's steam coal imports

Oil

Imports of crude oil have risen steadily in recent years. In 2016, China imported 7.6 mb/d of crude oil; an increase of 13% compared to the previous year. More than 1 mb/d of oil imports are now delivered to China via pipelines from Russia, Kazakhstan and Myanmar that were constructed over the last decade to diversify crude oil sources and limit reliance on seaborne trade via the congested Strait of Malacca. Although Russia recently displaced Saudi Arabia as its largest single source of crude oil imports, China nonetheless remains dependent on the Middle East for almost half of its import volumes.

Refining capacity in China has grown by almost three-times over the past 15 years, from 5.4 mb/d in 2000 to 15.6 mb/d in 2016, and its share in the global refining market has more than doubled from 7% to 16%. China now has more refining capacity than any other country except for the United States. During most of the first decade of this century, refining capacity grew roughly in line with rising demand for oil products. However, capacity additions started to outpace demand growth from the late 2000s (Figure 12.14), leading to a surplus of certain oil products, in particular diesel, and reduced utilisation of capacity. China became a net exporter of key refined products, with combined exports of gasoline, diesel and kerosene reaching over 500 thousand barrels per day (kb/d) in 2016, and its position as an exporter of refined products is now one of the factors driving its crude oil imports.

Figure 12.14 ▷ Refining capacity and demand for oil products in China



The surge in refining capacity since the late-2000s has made China both a large importer of crude oil and a net exporter of key refined products

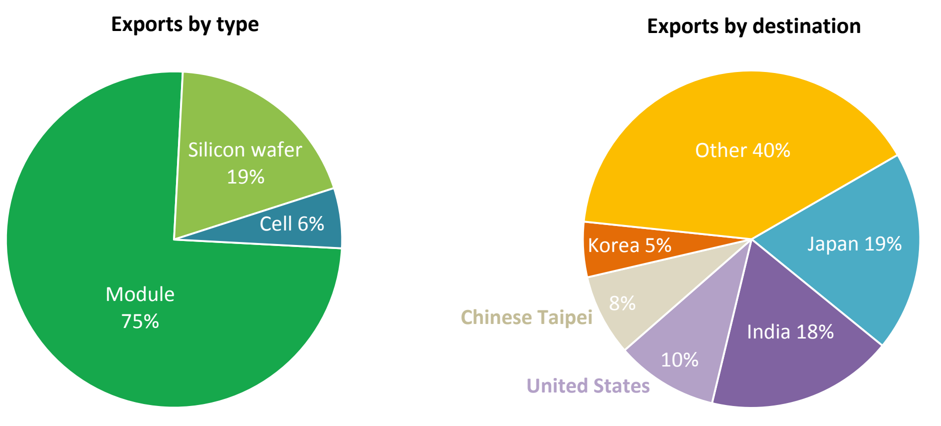
Natural gas

As with oil, natural gas imports have been growing steadily in recent years. China was the fourth-largest natural gas importer in the world in 2016: natural gas imports totalled 72 bcm, just under half of which were delivered as LNG from 16 countries, with the remainder coming by pipeline from Turkmenistan, Uzbekistan, Myanmar and Kazakhstan. Australia was the largest source of LNG and Turkmenistan the main source of pipeline imports. The first LNG regasification terminal started operation in 2006: by mid-2017, there were 17 LNG regasification terminals in operation with a combined capacity of some 70 bcm/year. Pipeline trade began in 2010 with the first line of the Central Asia Gas Pipeline, which connects with the domestic west-east system to supply the main gas-consuming areas in the East region. By 2016, the total capacity of the four pipelines in operation (three Central Asia Gas Pipelines and the China-Myanmar pipeline) was 67 bcm/year. The Power of Siberia, a pipeline to bring up to 38 bcm/year of Russian gas into Northeast China, is under construction and is expected to start deliveries in the early 2020s.

Clean energy technologies

China is a powerful force in the market for many renewable energy technologies. It dominates global solar manufacturing and has played a huge role in bringing down costs across the solar industry, both through innovation and through a huge expansion in manufacturing capacity that has often run ahead of demand. The rapidly growing domestic market absorbs most of the output, yet China was the world's largest solar product exporter in 2016 with its biggest markets in Japan and India and with sales of around $14 billion, including more than 20 GW of PV modules (Figure 12.15). China leads the global market for solar water heating technologies too: in 2015, Chinese companies were estimated to hold about 95% of the patents for core technologies in this area (CGI, 2015). China is also an important manufacturer of wind turbines, which are mostly sold in the domestic market. Nonetheless, China exported wind turbines to 28 destinations between 2007 and 2015 with its biggest export markets in the United States, Panama, Ethiopia, Australia and Pakistan: the 148 wind turbine units it exported in 2015 had a combined capacity of 275 megawatts (MW).

Figure 12.15 ▷ Solar PV exports from China, 2016



China dominates the global market for solar PV modules

Note: Share of solar PV export sales.

Nuclear

Chinese nuclear power technology has progressed rapidly in recent years. Co-operation with France, United States, Russia and Canada has allowed for a steady improvement in capacities and technologies and China has developed its own second- and third-generation pressurised water reactor (PWR) technologies. Since the 1990s, the China General Nuclear

Power Corporation (CGNPC) has built four nuclear reactors for Pakistan using second-generation PWR technologies (a fifth was finished in September 2017) and it is building another two reactors in Pakistan using its third-generation technology. CGNPC also signed a contract with Argentina in 2015 to build two reactors, with construction planned to start in 2018 and 2020. It is collaborating with Electricite de France (EdF) on the Hinkley Point C project in the United Kingdom, in which it has taken a 33.5% stake. Nuclear power technology has become an important element of China's export policy and Chinese companies are discussing new export possibilities with a range of countries including Argentina, Romania, South Africa and Turkey.

12.3 Factors affecting China's energy development

The projections for the energy outlook for China presented in the following chapters are derived by means of the same overall approach and scenarios as those in the rest of this *World Energy Outlook* (see Chapter 1), but with additional analysis to draw out the policy choices facing China and their implications, not only for the country but also the rest of the world.

- The **Current Policies Scenario** provides a set of projections based on existing policies and measures. It does not include announced policies or targets, and therefore provides a baseline against which to assess their impact.
- The **New Policies Scenario** is the primary focus throughout the analysis and it takes into consideration both existing policies and measures as well as China's announced policy ambitions, such as the targets set out in the 13th Five-Year Plan and other policy plans. In areas where specific policies have already been developed, the New Policies Scenario also incorporates the "Energy Production and Consumption Revolution Strategy" (described in section 12.3.5).
- The **Sustainable Development Scenario**, which sets out what it would take to provide universal access to modern energy services by 2030, to significantly reduce air pollution and to take urgent action to tackle climate change, provides a context for discussion of the longer-term qualitative aspirations for energy sector transformation, set out in the Revolution Strategy (see Chapter 15).

None of these scenarios is a forecast. Rather they provide a framework for considering China's energy outlook and the implications of various policies and strategic choices. The design and intent of these scenarios is usefully brought out by a look back to 2007, the last time that the *WEO* prepared an in-depth analysis of China, when the main scenario, called the Reference Scenario, did not take into account future policy evolution (Box 12.2).

In the remainder of this chapter, we introduce five of the factors that will play a huge role in influencing the direction of China's energy development over the coming decades: the economy; demographic pressures and urbanisation; environmental issues, including water constraints as well as emissions of local air pollutants and greenhouse gases; investment flows; and policies. Policies are particularly important in China, where the record of policy implementation and of reaching declared targets is very strong. There are many other elements in play, however, notably the market mechanisms that are set to take an ever-more important role in China's energy sector, as well as the structural changes underway in the economy.

Box 12.2 ▷ Looking back to the future: the China focus in *WEO-2007*

The Reference Scenario in the *WEO-2007* focus on China and India provided a set of projections that were based on the policies that were firmly in place at the time (in a way analogous to today's Current Policies Scenario). As such, it provided a business-as-usual set of projections that understated the eventual pace of growth of China's energy demand. A GDP growth assumption of 7.7% a year over the period to 2015 in the *WEO-2007* (reflecting the consensus of the time) turned out to be lower than the actual pace of economic expansion, which was closer to 10% a year, despite the global economic slowdown in the late 2000s. This pushed up China's total primary energy demand to 2 990 Mtoe by 2015, significantly above the 2 850 Mtoe projected for that year in the *WEO-2007* Reference Scenario.

The key differences in consumption by fuel between the projections and the actual energy mix in 2015 relate to subsequent changes in strategic energy orientation in China (once announced, these would now be incorporated as new policies in our methodology). The step-change in China's ambitions for renewables deployment is the main element, though the point also applies to a policy shift in favour of increased use of natural gas. Both of these policy directions shifted energy use away from coal. The share of coal in total primary demand projected for 2015 in *WEO-2007* is very close to the eventual outcome for that year (around two-thirds). However, the share of coal-fired power in the generation mix turned out to be 82% in 2015, six percentage points lower than the projected 88%, because of new policies that encouraged more solar, wind and natural gas-fired power.

Throughout the analysis, we reflect on the way that changes in some key underlying assumptions could affect China's path and the implications for global trends. China's size and its importance in global energy affairs mean that even relatively small variations in projected outcomes can have large knock-on effects. Chapter 15 examines in detail two key uncertainties:

- The first is the pace at which China moves ahead with its economic transition from heavier to lighter industrial branches, and from export-oriented industrial output to services and domestic consumption. We posit a ten-year delay in this transition, compared with the pace assumed in the New Policies Scenario, and explore the implications for a range of economic and energy indicators.

- The second is the possibility of China moving ahead even more rapidly with its clean energy transition, via a virtuous circle of more ambitious policies and more rapid cost reductions for some key renewable technologies.

In addition to these two extended analyses, Chapters 13 and 14 also include a host of other sensitivity cases and "what-if's", illustrating the way that different sets of circumstances and choices could move China away from the pathway projected in the New Policies Scenario. For example, we look in Chapter 13 at the issue of vehicle ownership levels in China, a critical indicator for future oil consumption. We examine what might happen if there is more widespread adoption of policies to limit growth in vehicle ownership in cities in the Central and Western regions, where ownership is relatively low today (and where most of the growth is projected to occur in the New Policies Scenario). In Chapter 14, we explore a range of potential pathways for production of shale gas in China, for which the resource estimates are huge, but actual production (with a few exceptions) has been slower than anticipated.

12.3.1 Economic transition

China has the world's second-largest economy and, even with the recent slowdown, it continues to expand at impressive speed. Growth in GDP has averaged almost 8% per year since 2010 (compared to an OECD[4] average of 1.8% over the same period), though this declined to around 6.8% in 2015 and 6.6% in 2016. In purchasing power parity (PPP) terms, China's GDP in 2016 was $21.7 trillion, or 18% of global GDP and GDP per capita is around one-third of the OECD average (measured in PPP terms). Industrialisation has been the main source of growth, and industry accounted for 39% of GDP in 2016, a share markedly higher than that of most middle-income, developing and OECD countries: the services sector accounted for little over 50% of GDP and the agriculture sector for 9%.

China's economy is undergoing a deep transition: the previous model of resource-intensive economic growth, which emerged in the early 1970s, is gradually giving way to a more sustainable model driven by consumption and the services sector, the so-called "new normal" (Figure 12.16). A key objective of the government's 13th Five-Year Plan is to double 2010 income levels by 2020 (Box 12.3). This will require annual average growth of 6% over the next few years compared with 8% in the preceding five-year plan. To bring about the changes it seeks, the government is promoting a series of "supply-side" reforms, with a view to reduce the debt and liability levels in the corporate sector and reduce excess capacity in key industrial sectors, including coal and power. The pace and depth of these reforms will have a major impact on the both the economic and energy transition.

All the scenarios in this *Outlook* for China use the same economic growth assumptions: average annual growth remains at 6.1% until 2020, before slowing gradually to around 5% per year by the 2030s. This means that China's economy expands by an average of 4.5% a

4. Organisation for Economic Co-operation and Development (OECD) member countries.

year through to 2040, and is almost three-times its current size by 2040. China's share of the global economy continues to expand, increasing by five percentage points by 2040 to 23%, and GDP per capita increases to almost three-times its current level. The structure of growth reflects the assumed transition towards a more domestic- and service-oriented economy and lower reliance on manufacturing and exports: the share of the services sector in China's GDP increases steadily to 64% in 2040, and the share of industry falls from 39% today to 32% in 2040.

Box 12.3 ▷ China's 13th Five-Year Plan

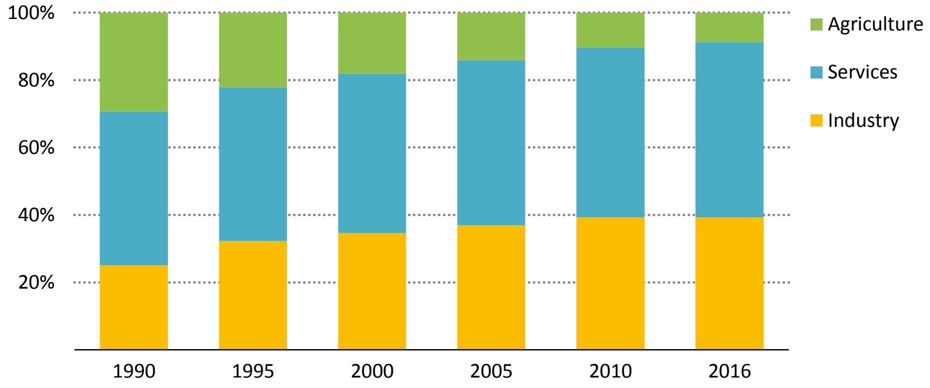
A succession of five-year plans has provided the overarching framework for China's economic and social development since the 1950s. Initially the main instrument of a planned economy, over time the plans have become more about setting policy direction and providing guidance, especially after China opened its doors to the outside world in 1978 and started to develop a more market-oriented economy. In March 2016, the government published the 13th Five-Year Plan (2016-2020) on Economic and Social Development. Based on this, central government departments and local governments must formulate sectoral/regional plans, for example on health, population, education, employment, culture and energy. The National Development and Reform Commission (NDRC) and the National Energy Administration (NEA) subsequently released their 13th Five-Year Plan (2016-2020) on Energy Development in December 2016. It sets out the main tasks and targets for the energy sector in the period to 2020, and the policies to support them. Some of the key indicators are presented in Table 12.3. The chapters that follow discuss in detail the way that these tasks, targets and policies shape our projections.

Table 12.3 ▷ Selected key energy and environment indicators in China's 13th Five-Year Plan

Indicator	2015*	2020
Nationwide total energy cap for all energy sources	-	Less than the equivalent of five billion tonnes of coal
GDP (trillion of CNY)	67.4	> 92.7
Permanent urban residents (%)	56.1	60
Services sector value added (%)	50.5	56
Non-fossil energy (% of TPED)	12	15
Reduction in energy intensity per unit of GDP (%)	-	15
Reduction in carbon emissions per unit of GDP (%)	-	18
Reduction in nitrogen oxides (%)	-	15
Reduction in sulfur dioxide (%)	-	15

Notes: * = where comparable. CNY = yuan renminbi.

Figure 12.16 ▷ **Changing structure of the economy in China**
(share of value added by sector)



China's rapid industrialisation is being followed by a robust expansion of the services sector in its economy

12.3.2 Demographics and urbanisation

Today approximately 1.4 billion people live in China – around one-fifth of the world's population – and the country has more than 140 cities with populations of over one million. The assumed demographic growth rate in China over the period to 2040 slows almost to a standstill (to an average of -0.1% per year), meaning that India overtakes China as the world's most populous country by 2022. The one-child policy, adopted in 1979 to curb population growth, and gradually eased from 2013 and again in 2015, is having a significant impact on the country's demographic profile, not only by slowing population growth, but also by reducing the share of the population that is of working age and introducing a noticeable gender imbalance. In the years ahead, older people are set to account for an increasing share of China's population, especially as life expectancy increases, generating a variety of social and economic challenges for policy-makers.

An increasing share of China's population is set to live in cities, continuing the trend of recent years: this share has already risen sharply from 36% in 2000 to 57% today, and reaches almost 75% by 2040 in our projections. This assumption is consistent with the government's own approach: under the government's National Urbanisation Plan for 2014-2020, a further 100 million rural dwellers will migrate to urban areas by 2020.

The implications of a more affluent and increasingly urban population for the energy sector are profound. In general, urban residents tend to consume more energy than those in rural areas, in large part because of differences in income levels. Urban sprawl, combined with inadequate provision of mass transit, can also push up consumption levels by increasing commuting distances and vehicle ownership, with potentially severe knock-on effects for air pollution. Conversely, the concentration of population in cities also offers scope for more energy efficient heating, cooling, transport and other services: this is a point that the Chinese authorities look very likely to devote attention and effort to at municipal, provincial and national levels.

12.3.3 Environment

China's rapid economic rise over the past two decades has had a major impact on its environment and on public health. The country is the world's largest source of CO_2 emissions, and local air quality in many of its major cities fails to meet national and international health standards. Outdoor pollution is the cause of around one million premature deaths each year and household air pollution accounts for a further 0.9 million early deaths each year. Poor air quality reduces today's average life expectancy in China by almost 25 months (IEA, 2016). The response to these hazards – especially the "fight against pollution" and the drive to "make the skies blue again" – has become a priority in national policy-making.

Air pollution

The Chinese government has long recognised the extent of air pollution and the data reflect the impact of recent policies to address the issue. Nevertheless, air quality remains an acute problem in many parts of the country. According to the Ministry of Environmental Protection (quoted in the preamble to the 13th Environment Five-Year Plan), almost three-out-of-four Chinese cities have not yet met the required domestic air quality criteria. The main industrial centres, in particular Beijing, Tianjin and the Hebei province, continue to register the presence of high levels of all major air pollutants. We estimate that only about 2% of the population in China breathes air with a level of fine particulate matter ($PM_{2.5}$) concentrations that complies with the World Health Organization (WHO) guideline, and only 64% of the population breathes air that meets the standards of even the most modest WHO interim target-1.

A notable tightening of China's policy in this area came in 2013 with the Action Plan for Air Pollution Prevention and Control. The Action Plan is a roadmap at provincial level for efforts to improve air quality over the period 2013-2017. It aims to reduce $PM_{2.5}$ pollution towards the National Ambient Air Quality Standard of 35 micrometres per cubic metre ($\mu g/m^3$) (the WHO interim target-1). It also contains detailed measures to address other pollutants. Although the Action Plan is national in scope, it focuses on three regions in particular: the Beijing-Tianjin-Hebei area, the Yangtze River Delta and the Pearl River Delta. These regions have $PM_{2.5}$ reduction targets of 25%, 20% and 15% by 2017 (compared with 2012 levels), with the $PM_{2.5}$ concentration for Beijing capped at an annual average 60 $\mu g/m^3$. In December 2016, the State Council published the 13th Five-Year Plan for Ecological and Environmental Protection (2016-2020). According to the plan, China's 338 largest cities must meet "good" levels of air quality 80% of the time by 2020, compared with 76.7% in 2015, and large cities that did not meet standards for $PM_{2.5}$ concentrations by 2015 have to cut their average by 18% by 2020, compared with their 2015 level.

CO_2 emissions

The drive to improve air quality has a strong overlap with China's broader efforts to reduce its carbon intensity and limit CO_2 emissions. China's receptive stance on action to combat climate change was a fundamental factor in bringing the negotiations on the Paris Agreement to a successful conclusion in 2015. In its climate pledges, China announced three major objectives:

- To achieve peak CO_2 emissions around 2030 and make best efforts to peak earlier.
- To lower CO_2 emissions per unit of GDP by 60-65% by 2030, against a baseline of 2005.
- To increase the share of non-fossil fuels in primary energy consumption to around 20% by 2030.

China's Nationally Determined Contribution specifies a number of policies and measures to achieve these objectives. Some of the actions that have been taken are administrative and prescriptive in nature, notably in relation to energy efficiency improvements and the mandatory closure of small power plants. Some make use of market mechanisms and instruments, notably the planned launch of a national emissions trading system in 2017 covering the power sector, which is to be extended later to include key energy-intensive industrial sectors: this follows various pilot schemes in seven major provinces since 2013.[5]

Developments in China, including the expansion of generation from renewables and nuclear, increased energy efficiency and – most significantly – the peak in coal consumption in 2013, all played an important role in the flattening of global energy-related CO_2 emissions that has taken place since 2014. We estimate that China's energy-related CO_2 emissions actually fell slightly in 2016, marking the first break in a strong upward trend since 2000. It is though too early to claim 2016 as an inflection point for China's CO_2 emissions: the relationship between economic growth and energy consumption is changing rapidly, and the deployment of low-carbon sources is gaining momentum, but there is still likely to be upward pressure on emissions in the years to come.

Water resources

Although China has almost 19% of the world's population, it has just 6.5% of global renewable water resources. Almost 80% of its renewable surface water resources and 70% of its groundwater resources are located in the Yangtze River Basin and the parts of China to its south. Conversely, almost half the population, two-thirds of its cropland and 40% of its industrial activity are to the north of the Yangtze River Basin (World Bank, 2009). Approximately 70% of its supply comes from surface water, and the rest from groundwater.

Some 30% of China's land area, which is home to almost half of the population, is currently experiencing high levels of water stress (Wang, Zhong and Long, 2016). China's available

5. Cement and aluminium smelting are the first industrial branches expected to join the emissions trading system (ETS). Chemicals and petrochemicals, construction materials, iron and steel, other non-ferrous metals and paper could enter the ETS market at a later phase.

water resources are further constrained by high levels of pollution that renders a significant portion of its surface water unusable. Approximately a third of China's lakes and rivers are unfit for human consumption, and almost three-quaters of the watersheds that supply water to thirty of the fastest growing cities in China suffer from medium or high levels of water pollution. Land use and degradation caused about half of this pollution, as fertilisers, pesticides and livestock waste contaminate water bodies, and industrial activity is the main source of the remainder. China has sought to develop alternative water sources but the pace at which it is building desalination plants has slowed in recent years.

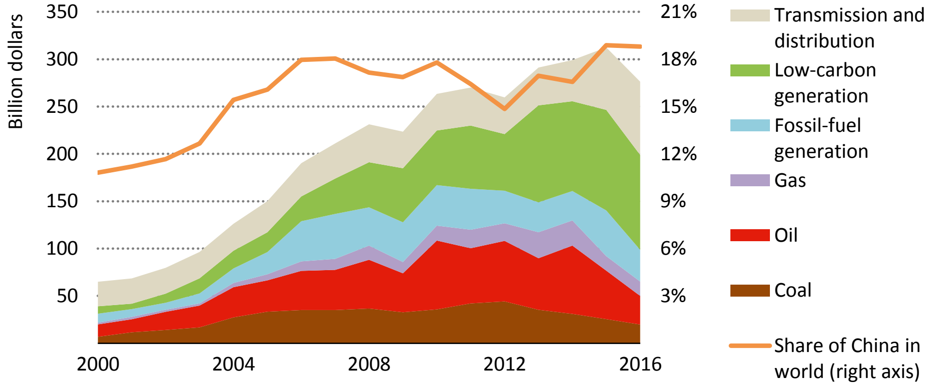
In recognition of the vital importance of water to its economic and social well-being, China has included a range of water-related targets in its 13th Five-Year Plan aimed at improving water quality, curtailing sources of water pollution, reducing water demand, increasing the share of alternative water resources, and improving water recycling and water conservation. Power generation accounted for 7% of China's total water withdrawals in 2016; coal-fired power plants, many of which are in water-stressed areas, were responsible for over 80% of this amount. In 2015, China released a Water Pollution Prevention and Control Action Plan, also known as the Water Ten Plan, containing its most comprehensive water policy to date. Aimed at protecting both surface and groundwater resources, the plan sets out ten measures with specific targets for 2020. These targets broadly covered several key action areas including control of pollution discharge with a strong focus on municipal wastewater treatment plants and industry; promotion of recycling and reuse throughout the economy; improved quality of drinking water; and strengthened management of water resources and better control over water extraction. The heightened focus on water management marks a break from the past when the focus was primarily on increasing water supply.

12.3.4 Investment

The scale and direction of energy investment is a crucial indicator for our *Outlook*. Many investments in energy-using infrastructure have long operational lifetimes, so past investment decisions in China continue to shape consumption well into the future. A case in point is the wave of investment in new coal-fired power capacity over the last ten years, which – unless it is retired or replaced early, or retrofitted with carbon capture and storage (CCS) – locks in patterns of Chinese coal use and emissions for decades to come.

Investment in China's energy sector in 2016 accounted for almost one-fifth of the estimated \$1.7 trillion in energy-related capital expenditure worldwide. Its composition showed significant changes from that of previous years. Rising spending on low-carbon electricity supply, networks and energy efficiency accounted for a greater share of investment (IEA, 2017). Upgrades to the distribution system and investment in several large-scale transmission projects (designed to help transfer power from inland provinces to the east and resolve the problem of curtailed solar and wind output) meant an increase in spending on electricity networks. Upstream spending on oil and gas in China has been held back by lower prices, and there has been a slowdown in investment in new gas infrastructure. Companies have tended to postpone projects in response to uncertainty about the pace of demand growth and the planned unbundling of the gas sector (see Chapter 14). However, investment in new oil infrastructure, both in transport and storage remained robust. China's coal-mining sector accounted for the largest part of global coal investment, but its share has been falling since a peak in 2012. In 2016, coal investment amount to around $14 billion, some 16% lower than the previous year, squeezed by continued overcapacity in many parts of the industry.

Figure 12.17 ▷ China energy supply investments



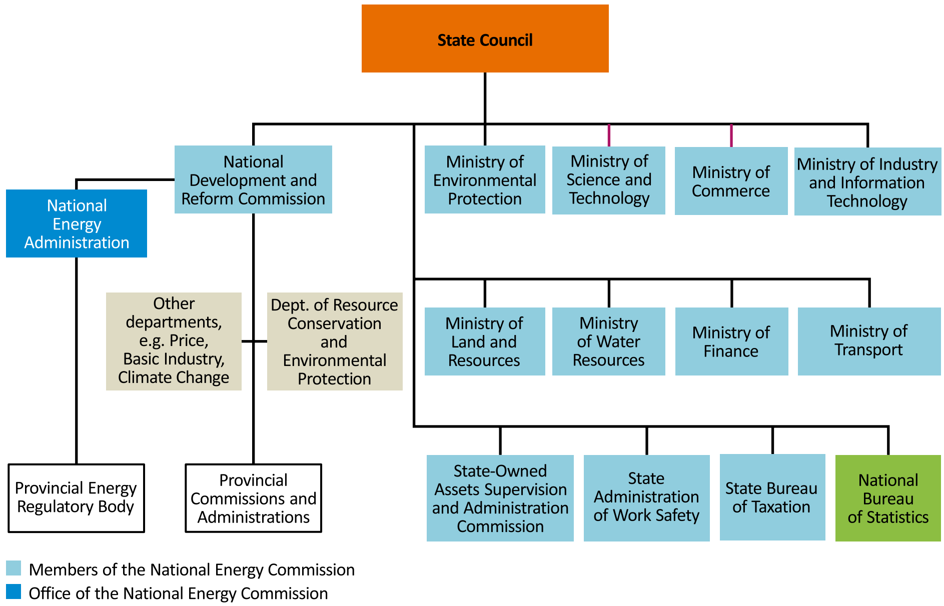
Low-carbon electricity supply and networks are driving energy investment in China

12.3.5 Energy governance and policies

The evolving administrative structure

A number of different bodies at national and local levels share responsibility for making and implementing energy policy in China (Figure 12.18). At central government level, the structure of the energy administration has evolved considerably in recent years. Individual ministries originally managed the various energy sources (e.g. coal, power, oil) and it was only in 1988 that China created for the first time a Ministry of Energy. China reversed this change five years later, and re-established line ministries for the coal industry and for power, along with several state-owned enterprises with activities and responsibilities in different parts of the energy sector. Another structural change took place in 2008 with the establishment of a new vice-ministerial level institution, the National Energy Administration (NEA), an organisation managed by the National Development and Reform Commission (NDRC). The NEA is responsible for making and implementing energy policies, such as the 13th Five-Year Plan, while the NDRC has a broader mandate for social and economic matters including climate change, pricing, energy efficiency, investment and resource conservation: energy plays an important role in all of these areas. In addition, directly under China's State Council, the State-owned Asset Supervision and Administration Commission (SASAC) is responsible for the supervision of China's State-Owned Enterprises and plays a key role in evaluating their performance and appointing top executives.

Figure 12.18 ▷ China's national administrative structure for energy



Alongside these leading institutions, a number of other government agencies have a say in China's energy governance. The importance of air quality in China has meant a prominent role for the Ministry of Environmental Protection, which is responsible for environmental standards and exerts increasing influence over the development and operation of energy projects. The Ministry of Science and Technology is responsible for technology innovation and for co-ordination of research and development activities in all areas including the energy sector. The Ministry of Land and Resources oversees the development of fossil-fuel resources and reserves, with the exception of hydropower resources, which fall under the Ministry of Water Resources. The State Administration of Work Safety is responsible for all work-related safety while the State Administration of Coal Mine Safety is responsible for coalmine safety. The Ministry of Commerce oversees energy trade. The Ministry of Finance and the State Bureau of Taxation are responsible for taxes and fees and are closely involved in any reforms that involve financial incentives. As well, provincial and municipal governments are taking an ever-increasing role in areas such as distributed energy and renewables as well as taking the lead in establishing both power and natural gas market systems at the provincial level.

In order to strengthen co-ordination among the various bodies charged with responsibilities in the energy sector, China established a National Energy Commission (NEC) in 2010. The NEC is chaired by the prime minister, and another vice prime minister (also a member of the Standing Committee of the Political Bureau) serves as deputy director. The NEC is the highest-ranked energy institution established in the Chinese system: all ministers of energy-related ministries are members, and the NEA serves as a secretariat. The NEC meets every one or two years to discuss key energy policies: its most recent meeting was in November 2016 to discuss and approve the 13th Five-Year Plan on Energy Development.

From central planning to policy guidance and regulation

For a long time, the energy sector was part of the planned economy: investments typically required specific government authorisations and approvals at various levels, depending on their scale and scope. This situation changed with the onset of market reforms in China, especially after 2013 when the government launched a far-reaching modernisation of administrative structures that streamlined procedures, delegated authority, strengthened regulation and regulatory bodies and limited the scope for central micro-management of economic affairs.[6] In the energy sector, this meant the abolition by the NDRC and NEA of more than a dozen approval procedures and the transfer of many other responsibilities to provincial administrations, so that, for example, the relevant province approves new coal-fired power plants, electricity grid extensions and oil and gas pipelines. As a result, the role of the NDRC and NEA is increasingly focused on policies and regulations, including development of guidance for plans and supervision of the implementation of those plans. Within the overall framework established at national level, there is considerable scope for provincial and local governments to decide on their own courses of action.

Role of state-owned enterprises

State-owned enterprises (SOEs) play an important role in the Chinese economy, in particular in the energy sector. The main SOEs initially sprang from the various energy-related ministries: for example, China National Petroleum Corporation (CNPC) and Sinopec derived from the former Ministry of Oil. Over time, they have gradually separated from the government and emerged as distinct corporate entities. Today over 20 national-level SOEs (out of a total of around 100 supervised directly by the SASAC) focus or operate in the energy sector (Table 12.4). These national SOEs, combined with a large number of local SOEs, make up the bulk of the China's energy industry today: they are also the main drivers in the implementation of China's "Belt and Road" initiative in the energy sector. The "Big Three" oil companies (CNPC, Sinopec and CNOOC) dominate the oil and gas industry; the "Big Five" power generation companies (Huaneng, Datang, Huadian, Guodian and the State Power Investment Corporation) dominate power generation, accounting for almost 45% of total capacity in 2015; and the State Grid Corporation of China (SGCC) is the world's largest utility company.

6. The former State Electricity Regulation Commission, established in 2003, merged with the NEA in 2013, and new departments were set up in NEA for regulation of energy markets. Provincial energy regulation bodies affiliated directly with the NEA are also authorised to oversee the compliance of new projects with the various energy plans.

Table 12.4 ▷ Main state-owned energy-related enterprises in China

	Oil and gas	Coal	Power			
			Grid	Generation*	Nuclear	Other**
China National Petroleum Corporation (CNPC)	●					
China Petroleum & Chemical Corporation (Sinopec)	●					
China National Offshore Oil Corporation (CNOOC)	●					
China Sinochem Group***	●					
China Shenhua Group		●		●		
China National Coal Group Corporation		●				
China Coal Technology & Engineering Group						●
State Grid Corporation of China			●			
China Southern Power Grid Corporation			●			
China Huaneng Group		○		●	○	
China Datang Corporation		○		●	○	
China Huadian Corporation	●	○		●		
China Guodian Corporation		○		●		
State Power Investment Corporation		○		●	●	
China Three Gorges Corporation				●		
State Development & Investment Corporation***				●		
China Resources Group***				●		
China General Nuclear Power Corporation				●	●	
China National Nuclear Corporation					●	
China Power Construction Corporation						●
China Energy Engineering Corporation						●
China Nuclear Engineering Group						●
Harbin Electric Corporation						●
Dongfang Electric Corporation						●
China XD Group Corporation						●
China Energy Conservation and Environmental Protection Group***						●

Notes: * Includes renewables. ** Includes energy project consulting, design and construction, energy equipment manufacture and energy efficiency. *** Business includes energy-related areas. ● = primary business; ○ = new business area.

China's energy-sector SOEs face similar challenges to all the country's SOEs, including weak governance, abundant non-commercial social responsibilities and a high level of debt. SOE reform is a high priority for the Chinese government, and is being carried out as part of the general reform initiative for SOEs launched in 2015, under which SOEs are being classified as either commercial or public utility/welfare firms, and commercial firms then further split into three types: competitive, monopoly and security-related. Each of these groups will have different reform objectives and be subject to different regulatory requirements and methods of performance evaluation. The other main elements of the reform include undertaking listings in China or overseas, setting up boards, merging SOEs to create globally competitive national champions, and introducing mixed ownership to attract private shareholders. Some of those reforms are underway in the energy SOEs, such as the mixed ownership reform in Sinopec and CNPC. Consolidation is also playing a role, a good example being the merger of the China Power Investment Group and the State Nuclear Power Technology Corporation to form the State Power Investment Corporation in 2015. Co-ordinating the transformation of the energy sector with the reform of China's SOEs is a very demanding task, but one that is vital for the success of China's energy transition.

Industry associations and think-tanks

China's energy sector has a variety of industry associations across the different fuels: the China Electricity Council, China Petroleum and Chemical Industry Federation and China National Coal Association are among the most influential. These are autonomous institutions with membership drawn from enterprises, research institutions and universities; although many associations also started as state entities and many continue to enjoy a measure of state financial support. Their main function is to act as a bridge between government and enterprises, but their responsibilities can also cover areas such as data collection, research, training and international activities.

There are also many energy-related think-tanks, most of which are affiliated to the government or the SOEs. Examples include the Energy Research Institute (affiliated to the NDRC), the China Electric Institute (affiliated to the SGCC), the China Electric Power Planning & Engineering Institute (EPPEI, affiliated to the China Energy Engineering Corporation) and the China Energy Engineering Institute (affiliated to the China Power Construction Corporation). Some of these organisations are authorised by the government to undertake a public function: for example, the EPPEI operates as the National Power Planning Research Centre with the authorisation of the NEA. National think-tanks such as the Development Research Centre of the State Council and Chinese Academy of Social Sciences are also active in the energy sector.

China's energy policy

The likely future evolution of China's energy policy is fundamental to our long-term analysis, and there is a rich body of available material on its long-term policy ambitions. The energy agenda is defined by the call for an "energy revolution", made by China's president in June 2014; this serves as broad guidance for all the energy five-year plans and policies, as well as the Energy Production and Consumption Revolution Strategy (2016-2030) jointly published by the NDRC and NEA in 2017. The "energy revolution" is focused on four areas: energy consumption, supply, technology and institutions (the latter point incorporating the need for international energy co-operation), with the overarching aim of securing a more secure, sustainable, diverse and efficient energy future.

A number of broader Chinese strategies and initiatives also affect the outlook for energy. A good example is the proposed direction of domestic economic structural reform: the "Made in China 2025" initiative, issued by the State Council in 2015, promotes a vision of China's manufacturing future that is fundamentally different from the past reliance on energy-intensive output. Instead, it places emphasis on advanced industrial designs that are greener and more innovative, supported by targets on energy and emission intensities. Energy co-operation, investment and trade also form an important component of the "Belt and Road" initiative that aims to enhance connectivity and co-operation along strategic land and sea routes to China.

Table 12.5 ▷ Main goals of China's Energy Production and Consumption Revolution Strategy, 2016-2030

Targets by 2020 (recall the existing main targets from the 13th Five-Year Plan)
• Total primary energy consumption to be maintained below 5 000 million tonnes of coal equivalent (Mtce), with a further reduction in the share of coal (Table 12.3).
• Share of non-fossil fuels to reach 15% in the energy mix, clean energy to become the main contributor to energy growth (Table 12.3).
• Carbon intensity to be reduced by 18% from 2015 levels, energy intensity to be reduced by 15% from 2015 levels.
• Energy self-sufficiency to be above 80%.
• Average power intensity (electricity consumed per unit of value added) in industrial enterprises to reduce by over 10%.
• Coal consumption per unit of power produced for all existing power plants to be lower than 310 grammes of coal equivalent (gce)/kWh, for new built power plants to be lower than 300 gce/kWh.
• Water use efficiency in main energy production areas to achieve advanced global level.
• Full implementation of coal-fired boiler air pollution emission standards and elimination of all old and inefficient coal-fired boilers in major air pollution prevention and control areas.
Targets and goals by 2030
• Access to commercial energy services in rural areas.
• Total primary energy consumption to be kept below 6 000 Mtce.
• Share of non-fossil fuels to reach around 20% in the energy mix.
• Share of natural gas to reach about 15% in the energy mix.
• Incremental energy demand to be met mainly by clean energy.
• Energy intensity to reach current global average levels.
• Share of non-fossil fuel power generation in the total power generation strives to reach 50%.
• Share of ultra-low polluting coal-fired power plants to be more than 80% of the fleet.
• Recall climate change commitments: o To lower CO_2 emissions per unit of GDP by 60-65% by 2030 from 2005 levels. o CO_2 emissions to peak around 2030 and strive to peak sooner.
Vision towards 2050
• Primary energy consumption level to be stable, with more than half coming from non-fossil energy sources.
• China to become an important participant in global energy governance.

To supplement the economy-wide 13th Five-Year Plan and long-term national strategies, China issued a separate 13th Five-Year Plan for Energy Development in 2016, which was followed by a series of sub-plans on coal, oil, gas, power, renewables, shale gas, coalbed methane, nuclear, hydropower, wind, solar biomass, geothermal and energy technology innovation (Box 12.3). These documents all identify specific medium-term binding or indicative targets, and a tracking mechanism to monitor progress. Targets and goals are increasingly designed to accommodate the shift in China's evolution towards a more market-oriented system. Regional, provincial and municipal plans were also created which mirror national plans.

A final category of policy document focuses on specific issues or challenges, for example the 2013 Action Plan for Prevention and Control of Air Pollution, the 2014 National Plan for Tackling Climate Change (2014-2020) and the 2016 Energy Technology Revolution Innovation Plan (2016-2030). In emerging energy areas such as smart grids and energy storage, the authorities also issue guidelines to support innovation, research and deployment.

While policies continue to playing a vital role in driving the energy transition, the broad process of market and institutional reforms reflects the government's pledge to "let markets play a decisive role in the economy". Energy pricing reform is playing a key role in this process, as China moves towards liberalisation of natural gas prices, changes to network regulation for electricity and gas, and the establishment of power trading and emissions trading platforms. The next phase of reform in the power, oil and gas sectors is defined by the Opinions of the Central Committee of the Communist Party of China and the State Council on Further Deepening the Reform of the Electric Power System in 2015, and the Opinions on Deepening the Reform of Oil and Gas System of the State Council in 2017.

Outlook for China's energy demand

The past engine of growth – a driver of the transition?

Highlights

- The way in which China's energy demand is met evolves in the New Policies Scenario, with low-carbon fuels increasingly to the fore. Coal demand declines, initially in industry and, from around 2030, also in power generation. Oil demand rises though 2030, but then plateaus due to road transport. Gas demand grows by 400 bcm to 2040, driven by industry and power, but also by residential consumers. The largest growth comes from low-carbon fuels: by 2040, they constitute nearly one-quarter of the energy mix, led by renewables.
- In end-use sectors, electricity becomes the leading energy source, overtaking oil soon after 2030. The industry and buildings sectors are the main drivers, together accounting for 90% of the growth. Transport also increasingly contributes to electricity demand growth as electric cars make strong inroads. Passenger car oil demand peaks by around 2030: one-out-of-four cars is electric by 2040.
- In the power sector, low-carbon technologies overtake fossil-fuel capacity by around 2025, and make up 60% of the total in 2040. Renewables account for more than 90% of low-carbon capacity: over the period to 2040, China is by far the largest market in the world for solar PV, wind power and hydropower. Solar PV rises particularly fast, as average costs drop below those of new gas-fired generation by 2020 and new coal around 2030, making solar PV China's cheapest source of electricity.
- As part of a reform package, China aims to make the power sector more agile and efficient. Encouraging competition, modernising operations and reflecting costs are key principles that lay the foundation for long-term progress. New transmission lines to facilitate electricity trade and power plant investment across China are another key ingredient to support a cleaner power mix, reduce pollutant emissions in the most populated regions and decrease the costs of electricity supply.
- Emissions of all air pollutants fall and concentrations of fine particulate matter drop. In 2040, almost half of the population lives in areas compatible with the national air quality standard (from 36% today); but only 3% live in areas that comply with the WHO guideline. Energy-related CO_2 emissions in China peak at 9.2 Gt before 2030, with industry peaking in 2014, buildings in 2019 and power in 2030.
- There are inevitably many uncertainties. For example, delay in reaching production targets in selected industries would increase cumulative CO_2 emissions by 5 Gt. The clean energy transition could also come faster than projected: the power sector targets of the Energy Revolution Strategy would require low-carbon generation to be 460 TWh higher in 2040. Stronger action to reduce air pollution from cars could cut up to 2.5 mb/d of oil demand and lead to a plateau in global oil demand by 2030.

13.1 China: shifting gears

The pace of China's energy demand growth over the past fifteen years has been breathtaking. Rapid industrialisation and urbanisation has underpinned strong economic growth and has been accompanied by a surge in energy demand: total energy demand has grown by 6.2% on average a year since 2000 while China's economy has quadrupled in size. Today, China is by far the largest source of coal demand, responsible for more than half of the global total; the second-largest source of oil demand (after the United States); and the fourth-largest user of natural gas (after the United States, the European Union and Russia). China is also home to the largest power generation fleet in the world, with one-out-of-four gigawatts (GW) of global installed power capacity; and to the third-largest fleet of cars in the world (after the United States and the European Union): almost one-out-of-three cars purchased on global car markets are sold in China. China has lifted hundreds of millions of people out of energy poverty since the start of the millennium. But there is still room for energy demand to grow further: even today, China's per-capita energy use is only about half that of the average of industrialised countries.

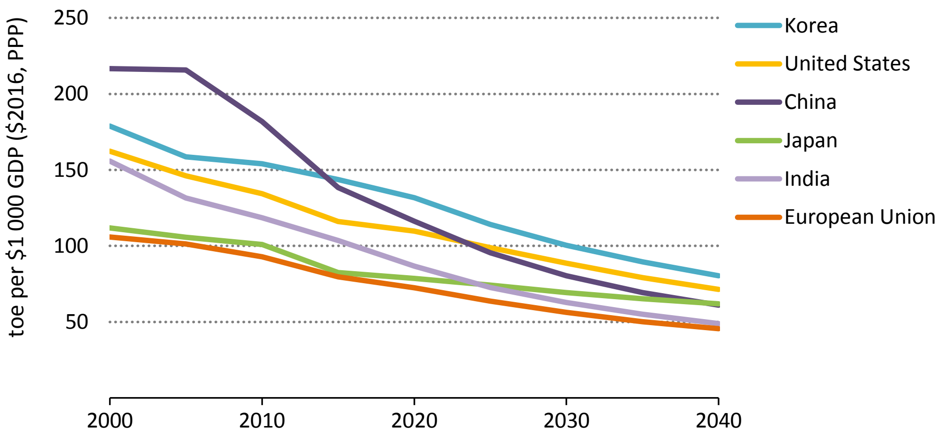
The rapid growth of energy demand has prompted debate in China about its future energy path. China currently imports around two-thirds of its oil, is grappling with air pollution in many cities and is the largest global emitter of carbon dioxide (CO_2). The policy response to these challenges in recent years has involved intensified efforts to curb future energy demand growth, a scale-up of low-carbon technology deployment, and strategies to reduce air pollution. Today China is the largest investor in the world in renewable energies, with 40% of global installations of renewable power generation capacity in 2016; it is the largest market for electric vehicles, at around 40% of global sales in 2016; it has almost 60% of final energy demand today covered by minimum energy performance standards (from practically zero in 2000) to increase the efficiency of energy use; and it has adopted a National Ambient Air Quality Standard of 35 micrometres per cubic metre ($\mu g/m^3$) for fine particulate matter ($PM_{2.5}$) to reduce air pollution. China is also on the verge of wider reforms, which would shift it away from a growth model that is based on energy-intensive manufacturing of intermediate products to supply both domestic and global markets towards a model that is oriented more towards services and supported by innovation-driven manufacturing of advanced technologies. This has major implications for future energy demand growth.

This chapter looks at the extent to which existing policy efforts are sufficient to address China's domestic energy policy challenges. It discusses emerging overall trends as well as detailed trends in end-use sectors and power generation, drawing on the results of the New Policies Scenario, which takes into account all existing policy efforts, as well as those that have been announced but for which implementing measures still have to be defined. But China's energy sector development is dynamic, and so this chapter also considers key uncertainties in the *Outlook*, considering their implications for global energy markets as well as for China.

13.2 Overview

The outlook for energy demand growth in China in the New Policies Scenario is significantly changed from its recent past. Energy demand growth slows to 1.0% per year, less than one-sixth of the pace of growth that China experienced since 2000, and total energy demand increase by around 800 million tonnes of oil equivalent (Mtoe) to 3 800 Mtoe over the next two-and-a-half decades – about the same level of growth as China previously experienced in just eight years between 2008 and 2016 (Box 13.1). The consequence is a rapid improvement in the energy intensity of economic growth, which falls by 3.4% per year on average through 2040 (measured in purchasing power parity [PPP]), the fastest rate of improvement of any country or region projected for this period (Figure 13.1). Per-capita energy consumption grows by one-quarter through to 2040: it overtakes that of the European Union by around 2035, although, by 2040, it is still only about half the level in the United States.

Figure 13.1 ▷ Primary energy demand per unit of GDP in selected regions in the New Policies Scenario



The energy intensity of GDP in China drops fastest among all countries; by 2040, China's economic growth is among the least energy-intensive in the world

Note: toe = tonnes of oil equivalent; PPP = purchasing power parity.

The outlook for energy demand growth in the New Policies Scenario is based on two important trends in particular that are assumed to unfold over the projection period. First, continuing the trend of the past two decades, population growth slows further, and the population grows older and more urban on average. By 2040, China's population is roughly as large as it is today; but 14% are older than 65 years, compared with just 4% today; and more than 70% live in urban areas, compared with 57% today. Together, these trends change the needs for energy services and slow energy service demand growth.

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Second, China rebalances its economy in line with its plans, focusing on quality of growth and consumption. This results in economic growth of 5.4% a year through to 2030, and 3.3% a year during 2030-40, accompanied by a structural shift in the value added contributed by different sectors to overall economic growth (see Chapter 15).

Box 13.1 ▷ Why does energy demand growth in China slow?

Assumptions about population growth and economic growth both slowing are central to the projected slowdown in energy demand growth in the New Policies Scenario, but the projection of a steep decline in energy intensity is also very important. This is driven by two factors. One is the effort to restructure the economy, which shifts energy demand growth away from energy-intensive industries to light industry branches and the services sector. The other is the effort to increase energy efficiency, which has received a great deal of policy attention in China in recent years. Today, 58% of China's total final energy demand is covered by minimum energy performance standards (MEPS), including regulations to reduce the electricity consumption of industrial motors; standards for "green buildings"; and fuel-economy standards for cars and trucks (see following sectoral discussions). Final energy demand in 2040 would be 60% higher in the New Policies Scenario without these efforts to restructure the economy and improve energy efficiency. Energy efficiency is the main contributor to constraining growth and accounts for nearly two-thirds of the savings.

13.2.1 Trends by fuel

The slowdown in energy demand growth is accompanied by an increased diversification of the fuel mix. Driven by China's strong commitment to low-carbon fuels, their use grows strongly in the New Policies Scenario, in particular in the power sector (Table 13.1). The result is that China meets the target of the 13th Five-Year Plan for non-fossil fuels to exceed 15% of the primary energy mix by 2020, and is set to go beyond the commitment for non-fossil fuels to reach 20% of the energy mix by 2030 set out in its Nationally Determined Contributions (NDCs) to the Paris Agreement (see power sector section below). By 2040, low-carbon fuels constitute nearly one-quarter of the total energy mix, led by renewables.

The power sector is a key contributor to renewables growth in the New Policies Scenario; by 2040, the combined output from all renewables rivals coal as the largest source of electricity supply. Wind and solar photovoltaic (PV) in particular become competitive with fossil fuel-based generation, as strong policy commitments in the 13th Five-Year Plan and beyond boost their deployment and help to drive cost reductions, and as efforts to reform the power market support their integration into the energy system, reducing current curtailment problems (Chapter 15). The growth in renewables helps to reduce the use of firewood and agricultural residues for cooking which is still prevalent in some provinces, in particular in the Northeast region (notably Liaoning and Heilongjiang) and in the West

(Sichuan). In the New Policies Scenario, China's continued efforts to improve access to clean cooking reduces the population that relies on inefficient cookstoves to around 80 million by 2040, less than a quarter of today's number.

Table 13.1 ▷ Primary energy demand by fuel in China in the New Policies Scenario (Mtoe)

	2000	2016	2020	2025	2030	2035	2040	CAAGR* 2016-2040
Coal	668	1 957	1 932	1 908	1 873	1 803	1 706	-0.6%
Oil	227	552	613	676	711	716	716	1.1%
Gas	23	172	234	309	374	428	469	4.3%
Nuclear	4	56	102	166	218	261	287	7.1%
Renewables	220	269	318	380	455	534	619	3.5%
Hydro	19	102	105	108	117	125	130	1.0%
Bioenergy**	198	112	118	131	149	169	192	2.3%
Other renewables	3	55	95	141	189	240	297	7.3%
*Fossil-fuel share****	*80%*	*89%*	*87%*	*84%*	*81%*	*79%*	*76%*	
*Fossil-fuel share*****	*93%*	*87%*	*84%*	*81%*	*78%*	*75%*	*72%*	
Total	**1 143**	**3 006**	**3 199**	**3 439**	**3 631**	**3 742**	**3 797**	**1.0%**

* Compound average annual growth rate. ** Includes the traditional use of solid biomass and modern use of bioenergy. *** Calculated using IEA methodology. **** Calculated using methodology of China's National Bureau of Statistics to aid comparability with China's published targets.

Among fossil fuels, natural gas plays the largest part by some distance in meeting energy demand growth to 2040, albeit from a low base. Natural gas plays only a minor role in China's energy today: at around 210 billion cubic metres (bcm) in 2016, natural gas accounts for only 6% of the overall energy mix, far lower than for example the United States (30%), Japan (24%) or the European Union (24%). Although the shorter term Chinese government target to increase the use of gas in the primary mix to at least 8.3% by 2020 is narrowly missed, the use of natural gas expands strongly in the New Policies Scenario: by 2040, demand is about 400 bcm higher than today, driven mostly by the industry sector (in particular light industries), which accounts for around 150 bcm of the total growth, and the power sector, which accounts for around 120 bcm. At more than 50 bcm, the residential sector is the third-largest contributor to natural gas growth, as gas use expands primarily for the purpose of space and water heating in eastern parts of China.

The strong rise in the use of low-carbon fuels and natural gas, and the slowdown in total energy demand growth mean that coal accounts for a smaller share of China's future energy mix. Today, coal constitutes around two-thirds of China's energy demand: coal grew by 8.9% per year on average over 2000-13 and contributed more than three-quarters of total energy demand growth over that period. Coal use has been in modest decline ever since and stood at just below 2 800 million tonnes of coal equivalent (Mtce) in 2016, or 52% of global consumption. Capping and then reducing the use of coal can make an important contribution to tackling air pollution problems, and is an important priority for China in terms of energy policy. The 13th Five-Year Plan adopts a maximum coal consumption target of 4.1 billion tonnes for 2020, and the Action Plan on Prevention and Control of Air Pollution has targets for individual provinces (including Beijing, Tianjin and Hebei as well as the Yangtze River Delta and the Pearl River Delta). Such targets, alongside the push to diversify the energy mix, mean that the recent trend of declining coal demand continues in the long term: in the New Policies Scenario, coal demand does not recover and declines annually by 0.6% per year on average to 2040. By 2040, coal demand is around 360 Mtce lower than today, and its share in China's total energy demand shrinks by almost 20 percentage points to around 45%.

Most of the net decline – some 290 Mtce – is attributable to iron and steel production, which is the second-largest source of coal consumption in China today (after power generation) and experiences a structural decline over the *Outlook* period. Some 70 Mtce is attributable to cement production, the fourth-largest source of coal consumption today, which is in structural decline over the projection period. Space heating in the residential sector sees coal gradually replaced by natural gas and electricity in the medium term, as China achieves its target from the 13th Five-Year Plan for energy development to increase the population with access to gas to 470 million by 2020. The power sector does not initially contribute to the overall decline in coal demand – coal consumption hovers around 1 500 Mtce until around 2030 – but the first wave of retirement of power plants that were built in the late 1990s and early 2000s pushes coal-fired generation into a slow structural decline from this point.

Oil has been the second-largest contributor to meeting energy demand growth in China since 2000, with demand reaching 11.5 mb/d in 2016. The transport sector was the primary driver: nearly half of total oil demand growth between 2000 and 2016 came from cars and trucks. Demand for oil as a feedstock in the petrochemical industry and for lubricants and bitumen also grew strongly. In the New Policies Scenario, transport continues to push up oil demand growth in the medium term, but average annual growth gradually slows: during the 2030s, oil demand plateaus as the growth of total passenger cars slows, the number of electric passenger vehicles rises sharply, and stringent fuel-economy standards for 2020 and beyond make cars more efficient. China's oil demand reaches 15.5 mb/d in 2040 in the New Policies Scenario, up 4.1 mb/d over today's level.

13.3 End-use sectors

China's focus on restructuring its economic growth model and on energy efficiency together moderate energy demand growth from end-use sectors (Table 13.2). In the New Policies Scenario, China adds around one-third to its current energy demand from end-use sectors through to 2040, about half of the energy demand growth that China exhibited since 2000. The "new normal" of China's economic development creates a shift between end-use sectors. The industry sector (including non-energy uses) retains its position as the leading source of final energy demand growth. But its contribution to total growth shrinks to just above 40%, down from around 65% since 2000. Transport makes the second-largest contribution to final energy demand growth, at one-third of the total, reflecting increasing demand for mobility: the pace of growth however is much lower than in the recent past, owing to China's efforts to improve fuel efficiency of cars and trucks. The buildings sector is the only end-use sector that sees a larger increase in energy demand to 2040 than it did between 2000 and 2016: as floor space per dwelling increases, energy demand in residential buildings for space heating and cooling rises strongly, and income growth leads to more household appliances and a higher level of electricity consumption. Energy demand from the services sector also rises rapidly, but from a much lower base.

Table 13.2 ▷ China final energy demand by sector in the New Policies Scenario (Mtoe)

						Shares		CAAGR*
	2000	2016	2020	2030	2040	2016	2040	2016-2040
Industry	304	972	1 026	1 113	1 131	50%	44%	0.6%
Transport	91	299	354	474	513	16%	20%	2.3%
Road	66	245	292	389	410	13%	16%	2.2%
Buildings	316	438	469	530	581	23%	23%	1.2%
Agriculture	22	52	54	53	48	3%	2%	-0.3%
Non-energy use**	58	164	201	252	285	9%	11%	2.3%
Total	**791**	**1 924**	**2 103**	**2 421**	**2 557**	**100%**	**100%**	**1.2%**
*Industry, including transformation****	*388*	*1 275*	*1 340*	*1 427*	*1 441*	*n/a*	*n/a*	*0.5%*

* Compound average annual growth rate. ** Includes petrochemical feedstocks and other non-energy uses (mainly lubricants and bitumen). *** Includes energy demand from blast furnaces and coke ovens (not part of final energy consumption) and petrochemical feedstocks.

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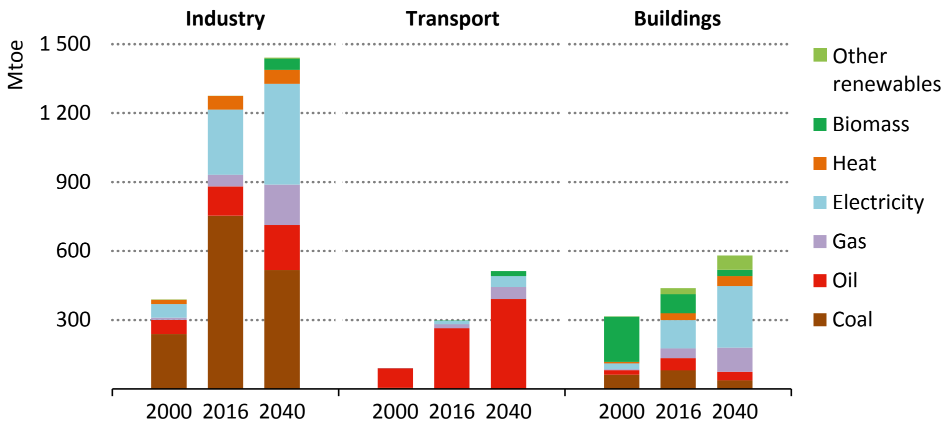
The slowdown of final energy demand growth in the New Policies Scenario is rooted in a raft of policy measures that have been adopted by the Chinese government in recent years. This includes most recently and most importantly the 13th Five-Year Plan, but also individual sectoral goals adopted among others by China's State Council (see sector discussion below). Beyond such targets, China has also issued wider strategic development documents to guide the long-term economic and energy transition, such as the Energy Production and Consumption Revolution Strategy (see Chapter 12). For the future evolution of final energy demand, the "Made in China 2025" initiative, issued by the State Council in 2015, is of particular relevance: it focuses on supporting the production of energy-efficient low-carbon technologies and new materials that could be applied across energy sectors, and it includes concrete targets to reduce the energy intensity of industrial production (Table 13.3).

Table 13.3 ▷ Key elements of the "Made in China 2025" initiative

Policy	Key targets and measures
Key sectors identified for government support	New energy vehicles, next-generation information technology, biotechnology, new materials, aerospace, ocean engineering and shipbuilding, rail transportation, robotics, power equipment and agricultural machinery.
Performance targets	• Improve industrial energy intensity by 18% in 2020 and 34% in 2025, relative to 2015. • Improve industrial CO_2 intensity by 22% in 2020 and 40% in 2025, relative to 2015. • Increase manufacturing value added by 2% in 2020 and 4% in 2025, relative to 2015. • Improve industrial value-added growth to 9.9% by 2025, compared with 5.9% in 2015. • Improve reuse of solid industrial waste to 79% by 2025, from 65% in 2015. • Increase rate of use of process control systems in key production processes from 33% in 2015 to 64% in 2025. • Increase internal research and development cost as a percentage of operating revenue of manufacturing firms from 0.95% in 2015 to 1.68% in 2025. • 7.5% average manufacturing labour productivity growth by 2020, remaining at 6.5% in 2025.
Industrial development targets	• Increase the share of essential spare parts and key materials produced domestically to 40% by 2020 and 70% by 2025. • Build 15 industrial technology research bases by 2020 and aim to build 40 by 2025. • Develop 1 000 green demonstration factories and 100 green demonstration industrial parks by 2020.
Policy and regulatory changes	• Upgrade manufacturing, in which 90% of manufacturing quality standards will meet international requirements by 2020 in key areas, compared with 70% today. • "100-1 000-10 000" energy conservation programme to regulate the top-100 energy consuming enterprises by the national government; the top-1 000 by provincial governments; and the top-10 000 by local governments.

Over the *Outlook* period, China's final energy demand undergoes a marked shift (Figure 13.2). Electricity accounts for more than half of final energy demand growth to 2040 and becomes the dominant source of final energy demand before 2040, overtaking coal and oil. The industry and buildings sectors are the main drivers of electricity demand growth to 2040, each accounting for around for 45% of overall growth, although the electrification of road transport emerges as an increasingly important source of electricity demand. Natural gas is the second-largest contributor to final energy demand growth, at more than one-third of the total: it gains ground in the industry and buildings sectors in particular. Around half the growth is in the industry sector, in particular from non energy-intensive industries, while in the buildings sector natural gas accounts for about 45% of total energy demand growth. Oil demand also continues to grow, driven by transport and petrochemicals feedstocks: their total growth amounts to some 4.7 mb/d, which is enough to offset the declines in all other sectors; they account for practically all oil demand growth through to 2040. The use of renewable energy sources also expands, with solar thermal and direct-use geothermal making particular inroads in the provision of water and space heating. Together, renewables (excluding traditional biomass) directly supply nearly 20% of final energy demand growth through to 2040.

Figure 13.2 ▷ **Energy demand by fuel in selected end-use sectors in China in the New Policies Scenario**



As China enters the next phase of development, the focus shifts from industry-led towards a services-led growth model with a focus on energy efficiency and electricity use

Note: Industry includes energy demand from blast furnaces, coke ovens and petrochemical feedstocks.

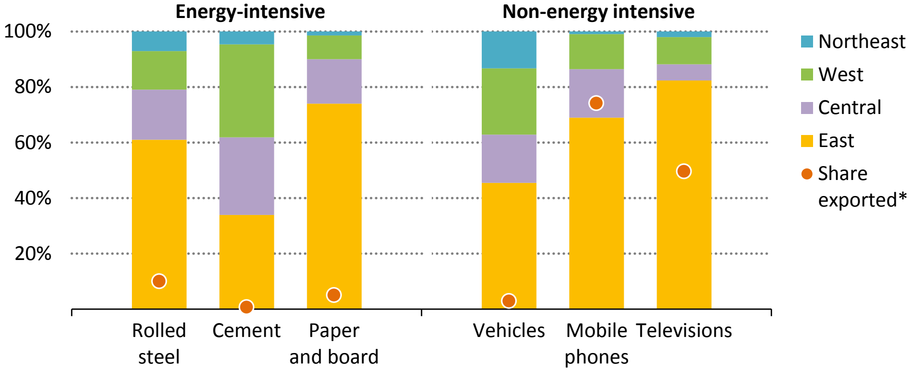
13.3.1 Industry

Background

Historically, the Chinese model of development has relied heavily on the industry sector, with energy-intensive industries supporting domestic infrastructure construction, heavy industries and the manufacture of consumer goods for export. This specialisation was reinforced after the country's accession to the World Trade Organization in 2001, which opened new international markets for Chinese goods. China overtook the United States as the top industrial producer by output in 2011, with about one-fifth of total global production. China is the world's leading manufacturer of steel and cement: in 2016, it was responsible for half the world's production of steel and over half of its production of cement, most of which for domestic consumption. China is also a leading global exporter of electronics, textiles, clothing and toys. Products for export tend to be mainly manufactured in the East region, while products for domestic consumption, though often produced in industrial zones in the East region, are also produced throughout the country (Figure 13.3).

The strong growth of China's industrial output has supported very rapid gross domestic product (GDP) growth, which has more than quadrupled since 2000. Successive five-year plans played a significant role in industrial development (see Chapter 12), establishing ambitious industrial production targets for key materials like steel and cement. The value added of the industry sector to GDP today is at 40%, one of the highest in the world, alongside Indonesia and Korea, but the investment boom in recent years led to considerable overcapacities in some sectors that the market failed to absorb, especially after the global financial crisis of 2008.

Figure 13.3 ▷ Output of selected industrial products by region in China, 2015



Eastern China dominates industrial production

* Share of product output that is exported in total domestic production. Note: Output is measured in volume.

Sources: National Bureau of Statistics of China; IEA analysis.

China's industry is primarily located in the coastal provinces, which are thriving centres of industrial production for the export of goods such as machinery, textiles, and chemicals. Labour-intensive manufacturing is concentrated in the East region in industrial clusters near coastal cities, while the inland provinces have developed metallurgy, mining, and other resource-intensive industries. The four most important industrial areas in China today are on the coast: Liaoning (iron and steel, machinery, chemicals and petrochemicals, and other heavy industries); Beijing-Tianjin-Tang (iron and steel, machinery, chemicals and petrochemicals, electronics, textiles); Shanghai-Nanjin-Hangzhou (the Yangtze River Delta, with a broad range of heavy and export-driven industries); and the Pearl River Delta (clothing, electronics, toys, food and beverage, and other light industry).

The size and speed of growth of its industry, especially its heavy industry, explains why China has dominated global energy demand trends in recent years. Between 2000 and 2016, more than 60% of global coal demand growth was in China, either as a result of direct industrial coal use, or indirectly as a result of rising electricity and heat demand that was satisfied by coal. As a result, the increase in the share of coal in global primary energy demand from 23% to 27% is closely linked to China's industrial development.

The energy intensity of China's industrial production has improved significantly over the last two decades: it is now half what it was two decades ago. Rapid economic growth allowed for very high rates of capital stock improvement and renewal, and for the installation of modern, energy-efficient equipment for capacity additions, especially in coastal areas, driven in part by foreign direct investment. The energy intensity of the steel sector, for example, improved by one-third between 2000 and 2016, and that of the cement sector halved over the same period. China has also actively pursued industrial energy efficiency policy: more than 80% of industrial energy demand is covered by mandatory energy efficiency regulation today, the highest percentage in the world, up from virtually zero percent in 2005 before first energy intensity targets were introduced under the 11th Five-Year Plan. And China has actively addressed industrial coal use under its past five-year plans: the closing of inefficient small industrial coal boilers has underpinned a small decline in industrial coal use since 2014.

Policy framework

The current design of China's policy framework for the industry sector is largely the legacy of past industrial development. Five-year plan targets for energy and emissions intensity are established at the national level, from which province-level targets are derived. Provincial targets are differentiated according to local circumstances: current industrial structure, level of efficiency and GDP are major elements of differentiation (Table 13.4). Balanced regional development has been a focus in the 12th and 13th Five-Year Plans, with the objective of extending industrial development to other regions of China. The 13th Five-Year Plan, in a continuation of the "go west" strategy, lays out a plan to develop the Western region via industrial clusters and industries related to local resources in order to drive improvements in living standards. The "revitalisation of the old industrial base" plan for the Northeast focuses on structural adjustment, reform of state-owned enterprises, and encouraging innovation in industry. The "rise of the Central region" strategy aims to relocate manufacturing centres to the central, inland region, and to encourage the development of high-tech industry. The "leading development" strategy in the Eastern coastal region aims at accelerated economic reform, and the development of research and development (R&D) and innovation centres, with the objective of moving up the value chain and producing higher value-added products for export. Some of this rebalancing of regions has already begun to occur, along with a convergence in GDP per capita of inland provinces; for example, industrial energy use in Xinjiang has more than quadrupled since 2000, and that of Gansu has nearly tripled.

A variety of other policies in place will affect future energy demand in the industry sector in China. These include the pilot-scale Emission Trading Schemes (ETS), in operation since 2013 in seven provinces, which will lead to a nationwide ETS, including cement and aluminium electrolysis, scheduled to begin in late 2017[1]; and the Action Plan for Air Pollution Prevention and Control, which targets three main industrial centres, (Beijing, Tianjin, Hebei (Jing-Jin-Ji) region, Yangtze River Delta and Pearl River Delta) and requires the restructuring of high-polluting enterprises (including through plant closures) together with audits and clean production retrofits in key industries.

1. Chemicals and petrochemicals, construction materials, and iron and steel, other non-ferrous metals, and paper could enter the ETS market in a later phase.

But China also recently adopted longer term guidelines for industrial development to support its wider economic restructuring process. While the past policy focus has been on the larger enterprises, the challenge is now to bring the 70 million small- and medium-size enterprises that are scattered across the country to the level of efficiency of the best, and to encourage innovation across industries. With the "Made in China 2025" initiative, China is planning to increase the efficiency of the industry sector. The intention is to provide a long-term vision for industrial development and to move up the value chain of the global manufacturing market by mid-century. Another national planning tool is the Energy Production and Consumption Revolution Strategy, which for the industry sector aims at controlling electricity demand growth by reducing electricity consumption per unit of value added by 10% by 2020, relative to 2015.

Table 13.4 ▷ Selected industry-related targets in China's 13th Five-Year Plan for 2020

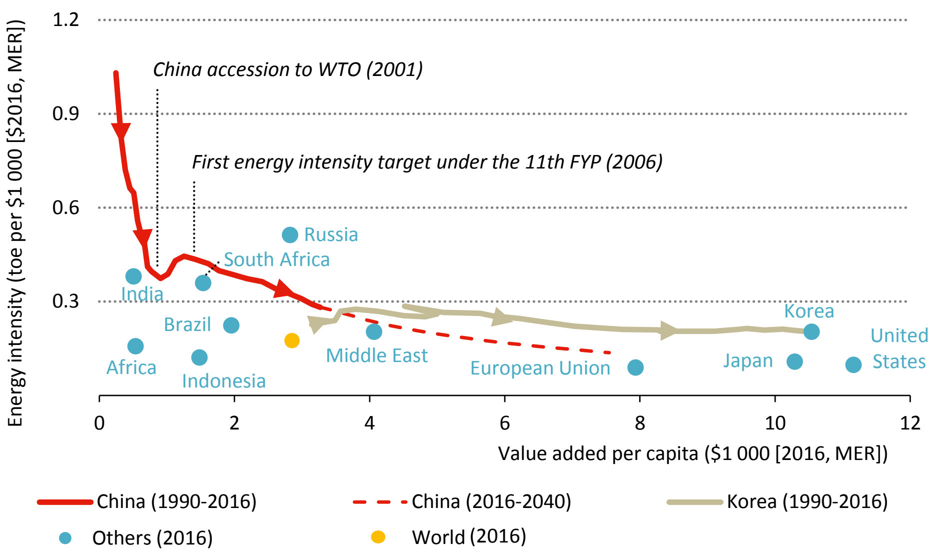
Coverage	Key targets and measures
Industry-wide targets	• Implement further air pollution control technologies in industrial boilers, and steel and cement making process equipment. • Focus on accelerating key branches including: high value-added equipment, integrated circuits, biotechnology, cloud computing, new energy technology and advanced materials.
Cement and other building materials plan	• 10% clinker capacity reduction. • 6% improvement in thermal energy intensity of clinker production. • 50% decrease in specific SO_2 emissions from plate glass. • 30% decrease in annual NO_x emissions from ceramics.
Iron and steel plan	• At least 10% decrease in energy consumption. • Increase utilisation rate to at least 90%. • 100-150 Mt capacity reduction for crude steel. • Improve energy intensity to less than 560 kgce/t steel. • At least 15% reduction in pollutant emissions.
Petrochemical and chemical plan	• 8% annual growth in value added. • 18% decrease in energy intensity • 18% decrease in CO_2 intensity per unit of value added.
Non-ferrous metals plan	• 18% decrease in energy intensity per unit of value added, for enterprises above threshold income level. • 15% decrease in total annual SO_2 emissions.
Textiles plan	• 6-7% annual increase in value added, for enterprises above threshold income level. • 18% decrease in energy intensity.
Light industry plan	• Shift light industry from coastal region to Central and Western regions. • Construct modern industrial clusters to encourage technology development, energy savings and emissions reductions.

Notes: SO_2 = sulfur dioxide; NO_x = nitrogen oxides; kgce/t = kilogrammes of coal equivalent per tonne.

Trends in the New Policies Scenario

In the New Policies Scenario, industrial energy demand growth slows dramatically, to 0.5% per year on average to 2040, compared with almost 7.7% since 2000, continuing the slowdown in demand growth since 2011. Industrial activity growth slows to 3.6% per year through 2040, from 10% per year since 2000, continuing the trend that started with the implementation of the first energy intensity targets in the 11th Five-Year Plan (Figure 13.4).[2]

Figure 13.4 ▷ Industrial development trajectory and energy intensity in China in a global context in the New Policies Scenario



Industrial energy efficiency in China continues to improve rapidly through to 2040

Notes: WTO = World Trade Organization; FYP = Five-Year Plan. Industrial energy intensity is calculated as the total industry energy demand, including blast furnaces and coke ovens as well as petrochemical feedstocks, divided by the industry value added in 2016 constant dollars at market exchange rates (MER). The industry value added per capita uses the same monetary unit as in the energy intensity calculation.

The slowdown in industry energy demand growth is accompanied by a significant shift in fuel demand, driven both by the relative competitiveness of fuels and by policies to upgrade the quality of industry production. The industry sector is the main contributor to the peak and decline of China's coal demand in the New Policies Scenario, as industrial coal demand falls by 30% by 2040 compared with 2016. Instead, energy demand growth is largely supported by electricity and natural gas over the projection period. The growth

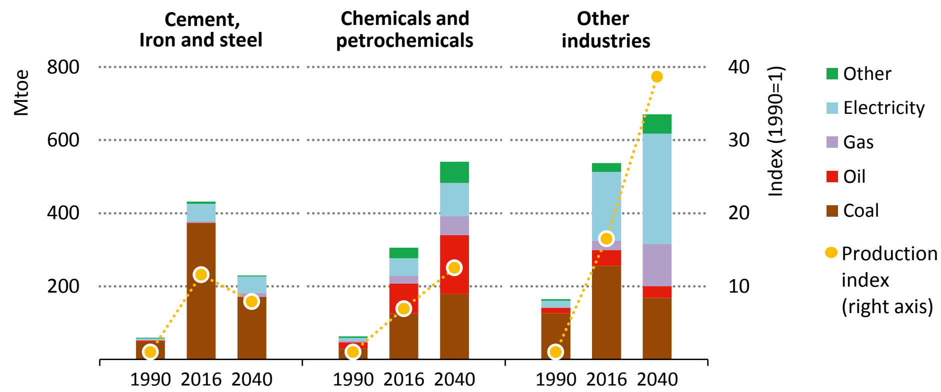
2. Improvements to energy intensity were reversed after China's accession to the WTO, in particular due to change in its industrial structure that became more export-oriented.

in electricity demand alone, at 1 800 terawatt-hours (TWh), accounts for most of the net total growth of industrial energy demand, a marked change from the contribution of 25% that electricity had in total industry demand growth since 2000. The strongest growth in electricity demand occurs in the chemicals and non energy-intensive industrial sectors, both due to increased production and to the deployment of electricity-based heat technologies, including heat pumps. Growth in natural gas use, at 152 bcm, is equivalent to three-quarters of the net industrial energy demand growth, compared with less than 5% since 2000. The element of continuity with the past is oil demand growth, which climbs by 1.7 mb/d through 2040, relative to 2016, practically the same growth as over 2000-16. Feedstock use becomes the single largest source of oil demand growth in industry by 2040.

In the New Policies Scenario, industrial restructuring makes a big difference to future energy demand. Today, four heavy industry sectors (iron and steel, chemicals and petrochemical, cement and aluminium) represent almost three-quarters of industrial energy use, 80% of industrial coal consumption, 70% of industrial oil demand, and 55% of each industrial gas demand and industrial electricity demand. Over the *Outlook* period, the weight of these sectors in industrial energy use decreases to around two-thirds by 2040, around ten percentage points below its current level. Energy demand from the steel and cement industries decreases greatly, by a combined 250 Mtoe, driven both by efficiency improvements and by declining production. This reduces coal use in these sectors in particular. Total industrial coal use falls back to the levels of about a decade ago. The decreases in production are linked to efforts to close the least-efficient plants in the short and midterm (China plans to cut 150 million tonnes [Mt] of steel capacity by 2020 and 10% of its clinker capacity by 2020) and to the overall plan for economic transformation. Crude steel production decreases from more than 800 Mt in 2016 to just below 600 Mt in 2040; cement production falls from more than 2 400 Mt in 2016 to about 1 600 Mt in 2040. Other energy-intensive sectors such as paper and aluminium see their energy demand either stabilising or increasing slightly.

But not all energy-intensive sectors see a decline in their energy demand (Figure 13.5). The largest absolute increase in energy demand across all industry sectors comes from the chemical and petrochemical subsector where production grows significantly, including a doubling in production of olefins, which is offset by declines in other sectors, notably cement, and iron and steel. All forms of energy contribute to this growth, including coal (especially in coal-to-olefins, methanol and ammonia production), oil (a key petrochemical feedstock), natural gas, electricity, heat and renewables. About a quarter of feedstock use in China in 2040 is coal, used frequently in the methanol-to-olefins and coal-to-olefins process routes for producing high-value chemicals. The development of the chemical and petrochemical industry supports productivity gains in the agricultural sector, and aids the development of other manufacturing sectors (such as manufacturing of finished plastic-based products): it could also contribute to reducing air pollution from transport fuels through the use of methanol (see section 13.3.2).

Figure 13.5 ▷ China industry energy mix and related output by sector in the New Policies Scenario



Rebalancing industrial activity increases energy efficiency and changes the fuel mix; the chemical subsector becomes the main industry source of energy demand growth

Notes: Industrial production level in the iron and steel and cement subsectors refer to tonnes of output. In the chemicals and petrochemicals subsector, it is the sum of basic chemicals production in tonnes of output, including ethylene, propylene, aromatics, ammonia and methanol. For other industries, it is the sum of all other industry subsectors' value added in constant $2016 in MER terms.

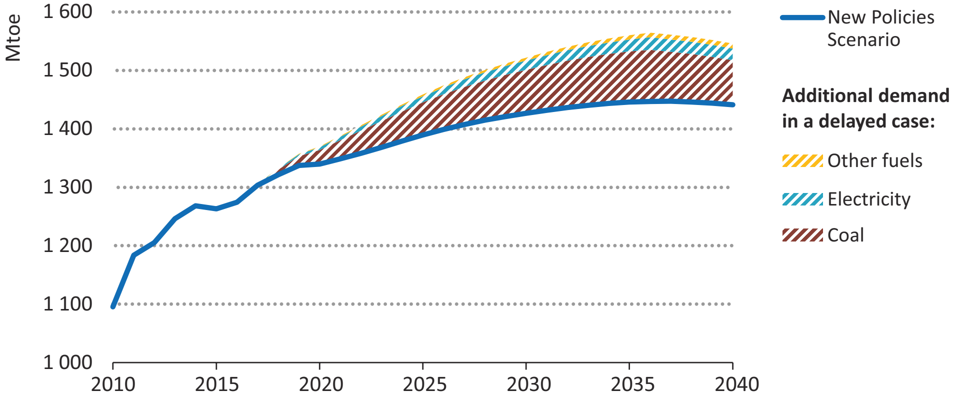
Despite the importance of chemicals and petrochemicals for energy demand growth, the bulk of the growth in gas and electricity demand comes from less energy-intensive industries like electronic equipment or machinery manufacturing: these sectors tend to be more reliant on natural gas and electricity than traditional energy-intensive sectors, and to have less need for high-temperature heat or fossil fuels as feedstocks or reducing agents. Electric-driven motor systems typically play a larger role in these sectors as well, driving electricity demand despite strong efficiency gains from MEPS and efficiency gains in end-use equipment, with, most motor systems now needing to meet IE3[3] international performance standards.

In the New Policies Scenario, the share of electricity in non energy-intensive sectors increases by ten percentage points to 47% in 2040, which is about a third of the change seen between 1990 and 2016. Gas demand growth in non energy-intensive industries accelerates compared with the last few decades. Increasing the use of natural gas is an important policy goal for China: in the New Policies Scenario, the increase in demand in non energy-intensive industries stems mostly from the new industrial clusters, and from fuel switching in existing industries in locations where supply is available, partly to meet

3. IE3 refers to the "premium efficiency" level for electric motors of the classification established by the International Electrotechnical Commission (IEC).

environmental objectives. Where gas is not available, the alternative is to close industrial facilities where they are old, polluting and inefficient, in the same way as with heavy industries. In many cases, facilities cannot be retrofitted, so they remain in operation until closure.

Figure 13.6 ▷ Impact of a delay in the reduction of steel and cement production on total energy demand from industry in China, relative to the New Policies Scenario



A delay in the restructuring of the steel and cement sectors would increase industrial energy demand, particularly coal

Notes: The analysis assumes that reductions in cement and crude steel production are delayed compared to the targets of the 13th Five-Year Plan. It would mean that capacity closures designed to reduce overcapacity are delayed, which would prevent decreases in production over the next two decades as a result of capacity lock-in. Production per capita of crude steel and cement is assumed to remain constant through 2035, after which they begin to decrease in line with the targets. Industry energy use includes blast furnaces and coke ovens, as well as petrochemical feedstocks.

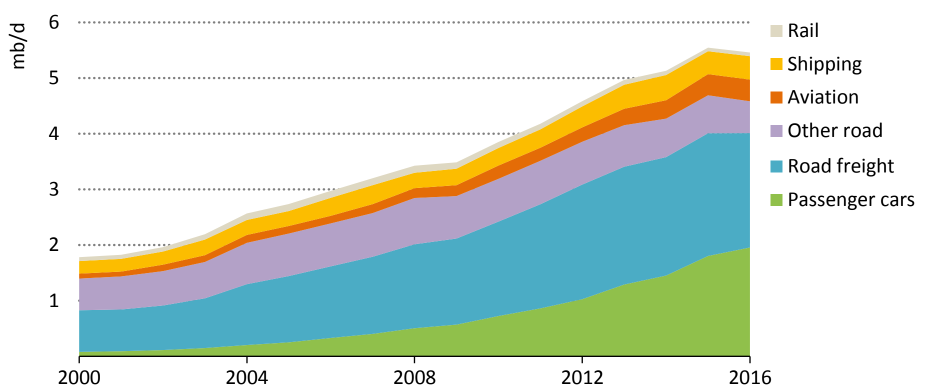
China's plan to transition away from its traditional focus on energy-intensive industry sectors towards high-tech, high-value, less energy-intensive industrial activities is a key driver of the energy demand outlook in the New Policies Scenario. Achieving its goals would help China succeed in the transition to a more balanced macroeconomic growth model that is similar to that of today's developed economies, as well as to achieve its energy and environmental objectives. It is, however, an ambitious undertaking, with many intermediate targets in the short and medium term (see section 15.3.2 in Chapter 15 for a discussion of the changes in the macroeconomic structure in the New Policies Scenario). It is in the nature of such wider economic reforms that their achievement can face unexpected obstacles, including, for example, delays in the reduction of production levels compared with the original plan as domestic demand for these materials might get boosted. Such potential delays would materially change the outlook for industrial energy demand, increasing energy demand (in particular for coal) and related CO_2 emissions (see section on environmental implications below). They could delay the reduction of overcapacity in the steel and cement sectors, so that coal demand in industry would not begin to decline until after 2020. A delay in the restructuring of these subsectors to 2035, would lead to more than 800 Mt additional cement production and more than 150 Mt more crude steel production in 2040, relative to the New Policies Scenario: this would equate to a global increase of cement and steel production capacities of almost 20% and about 10% respectively. In such a case, China would use over 100 Mtoe more energy in 2040, of which around three-quarters would be coal (Figure 13.6). In 2035, the year in which the increase is the largest, coal use would increase by over 120 Mtce, nearly equal to today's annual coal demand of South Africa.

13.3.2 Transport

Background

Not so long ago, China was known for its widespread use of bikes. Yet since 2000, the number of cars on the road in China has increased by a factor of more than 25 and today China is the biggest car market in the world, with more cars being sold per year than in the United States, Japan and Germany put together. Other forms of transport have also seen strong growth: over the same period, the number of motorbikes has grown by a factor of five, and the number of passengers on domestic flights by a factor of eight (World Bank, 2017). This surge in passenger mobility has been accompanied by strong growth in freight activity: the amount of goods carried on China's streets (expressed in tonne-kilometres travelled) has grown by a factor of three since 2000. As in other countries, the growth in transport demand has been mostly satisfied by oil (Figure 13.7). The result is that the transport sector accounted for 55% of the increase in China's oil demand between 2000 and 2016. Today, the sector relies on oil for nearly 90% of its fuel needs (the remaining 10% is split almost equally between natural gas and electricity).

Figure 13.7 ▷ Oil demand in China's transport sector, 2000-2016



Road freight remains the biggest source, but oil demand for passenger cars has been the fastest growing, pushing up to a third of transport oil demand in 2016

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The strong rise in mobility and freight activity has played a vital part in China's economic growth and increasing welfare, but it has also prompted important policy concerns. On the one hand, transport is an important cause of China's oil imports. On the other hand, it is a source of environmental problems, particularly in cities where congestion and air pollution are pressing problems. China has actively introduced pollution emissions standards to tackle these problems and is gradually catching up with the world's most stringent standards.[4] Many cities have restricted or are looking to restrict the number of new cars that can be licensed.

Policy framework

The government response to the strong growth in the passenger car fleet has many facets. In addition to increasingly stringent standards on air pollutant emissions, fuel quality and vehicle fuel economy, China also has ambitious industry targets and generous tax incentives to foster the growth of new energy vehicles (NEVs) (Table 13.5). Electric vehicles (EVs) are a key target: China is already the largest market for EVs, with around 650 thousand EVs on the road today (one-third of the global total), and is seeking to build up further its vehicle and battery manufacturing capacities, in line with its industrial "Made in China 2025" initiative. China also seeks to reduce oil demand growth from road freight transport: fuel-economy standards for heavy-duty commercial vehicles have been in place since mid-2012, making China only one-out-of-five countries to have such standards (others being Canada, India, Japan and United States).

China is also supporting alternative fuels, although the extent of this varies from province to province. The use of methanol as a liquid fuel reached more than 0.5 million barrels per day (mb/d) in 2016, and was for the most part produced domestically using coal, coking gas and natural gas. Blended into the gasoline pool, it enhances combustion performance and Shanghai and 13 provinces have approved local standards for methanol blends; a national standard for a 15% blend of methanol is pending approval. China is also the world's fourth-largest producer and consumer of ethanol, although less than 20% of it is used in transport (the remainder is used for beverages/liquors and chemicals production). The 13th Five-Year Plan aims at a doubling of fuel ethanol production and a near three-times increase of biodiesel, which is challenging: China's industry struggled to reach the targets of the 12th Five-Year Plan, and the expansion of domestic production is further complicated by the removal of the "generation 1.0" production subsidy in 2016 and the "generation 1.5" subsidy that will take place in 2018. In 2016, Guangdong, Jiangsu and Hebei adopted an E10 blending mandate (i.e. 10% of ethanol in gasoline in volumetric terms), and an additional 11 provinces and 40 municipalities are acting as pilot zones for mandatory ethanol blends.

4. The current nationwide light-duty vehicles emission standard is China 5 (equivalent to Euro 5), active from 2017 for gasoline engines and 2018 for diesel engines. Diesel heavy-duty vehicles emissions are subject to China V (equivalent to Euro V) standards since mid-2017, which caps NO_X at 2.0 grammes per kilowatt-hour (g/kWh) and PM emissions at 0.03 g/kWh. China 6 is under discussion for 2020-23 for both engine types.

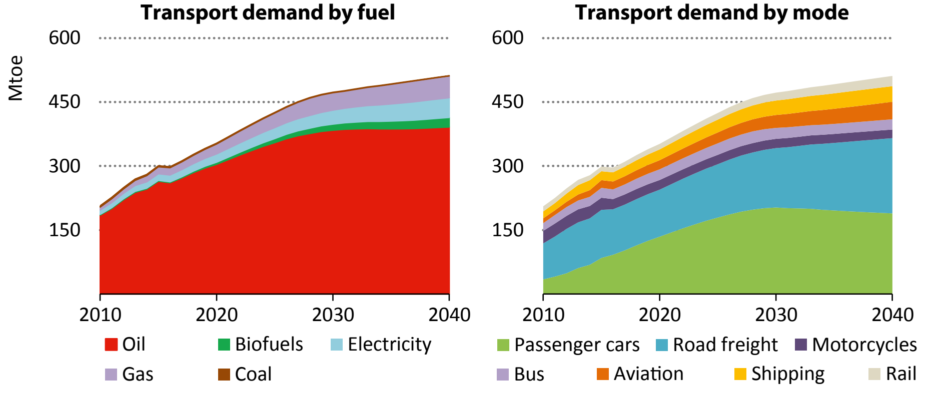
Table 13.5 ▷ Selected transport sector policies in China and selected cities

Policy	Coverage	Key targets and measures
Energy conservation and new energy vehicle industry development	National	• Corporate average fuel consumption limit for new cars of 5.0 litres per 100 kilometre (l/km) in 2020.
13th Five-Year Plan and related initiatives	National	• Reach 5 million new energy vehicles (NEV) on the road in 2020, with a manufacturing capacity higher than 2 million per year. • Production target of 5 million tonnes of ethanol and 2 million tonnes of biodiesel in 2020. • Develop battery performance and strengthen efforts to recover used batteries. • Better network interconnections between city clusters. • Construction and upgrading of 30 000 km of highways. • Building more than 3 000 km urban railway connections. • Coverage of 80% of big cities with high-speed railways. • Construction of 50 new airports. • Air traffic management system to offer support to 13 million aircraft movements per year. • For aviation cargo, 4% reduction of annual average energy consumption and CO_2 emissions per tonne-km by 2020.
Long-term development plan for the automotive industry	National	• Corporate average fuel consumption for new cars of 4.0 l/100 km in 2025. • Level of car material recycling of 95%.
Notice of the adjustment of new energy vehicles' financial subsidies policy	National	• 20% reduction of 2017 subsidies from governments for NEV purchase, compared to 2016. • Local subsidies shall not exceed 50% of central government subsidy level.
Beijing Electric Vehicle Charging Infrastructure Special Plan	Beijing city	• Projection of 600 000 electric vehicles by 2020. • Charging service within 0.9 km radius.
Work Plan on New Energy Car Development (2017-2020)	Guangzhou city	• All buses that use petrol and diesel will be replaced with pure electric buses.
13th Five-Year Plan on EV and charging pile development	Zhejiang province	• Satisfy the need for charging 230 000 EVs.
Implementation plan on air pollution control in crucial industrial sectors	Yangtze River Delta	• Road fuels shall be upgraded to national standard V. • NEV share should be more than 65% in 2020.
Proposed plan on accelerating the promotion of new energy vehicles	Chongqing city	• Yuan renminbi 10 000-30 000 additional subsidy for NEVs. • Pay toll exemption for NEVs until end-2020.

Trends in the New Policies Scenario

Future demand for passenger mobility and freight transport continues to rise sharply in the New Policies Scenario. Road freight activity (expressed in tonne-kilometres) increases at an average 3.6% per year, broadly mirroring GDP growth. Road passenger vehicle activity (expressed in passenger-kilometres) grows at a more moderate rate of 3.2% per year, as a result of the slowing of population growth, increasing urbanisation and an increasing switch to rail that is promoted by the 13th Five-Year Plan. Aviation activity also increases, at an annual rate of 5.5%. Transport fuel demand rises strongly in response, with most growth focused on the period to 2030, during which demand rises by 3.3% per year on average: fuel demand growth levels off thereafter, with the growth rate over the last ten years of the projection period one-quarter of the rate before 2030 (Figure 13.8). The main reason for this levelling off is a decline in fuel demand from passenger cars, which peaks around 2030 as the growth in the number of cars flattens, vehicles become more fuel-efficient due to ambitious fuel-economy targets, and electric cars make significant inroads in the passenger vehicle market.

Figure 13.8 ▷ China energy demand in transport by fuel and mode in the New Policies Scenario



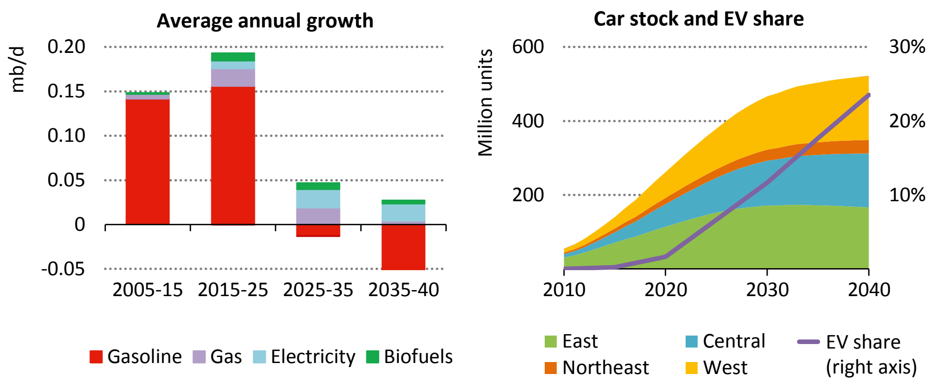
Oil remains the mainstay of transport fuel use, but plateaus in 2030 as demand from passenger cars peaks and alternative fuels, in particular electricity, make inroads

In the New Policies Scenario, EVs account for almost one-fifth of the new car sales in 2025, driven in the short term by government subsidy and in the longer term by policies that promote their adoption in cities; as a result, one-out-of-four cars on the road in China in 2040 is electric. Road freight transport becomes about 30% more efficient in 2040 than it is today as goods transportation becomes increasingly efficient as a result of improvements in road infrastructures, higher truck capacities, and communication and information technologies, and as trucks become more fuel-efficient through the enforcement of the related standards. Fuel demand from non-road transport modes, however, continues to grow at a rapid pace, rising at 3.4% per year for aviation, 3.2% for rail and 2.3% for shipping.

Oil remains the backbone of transport fuel demand, but its pace of growth changes over the *Outlook* period. Gasoline use from passenger cars continues to drive transport oil demand through to 2030, but then goes into decline. Diesel use (mostly from freight trucks) continues to grow robustly through to 2040. Kerosene use in aviation and heavy fuel oil use in shipping increase fastest among all oil-based transport fuels. Overall oil demand in transport plateaus from 2030 onwards, and its share of total transport energy use drops to just above three-quarters in 2040, down from nearly 90% today. The remaining quarter of demand comes from a trio of other fuels which all experience significant growth in the transport sector: biofuels use grows by more than 10% per year, natural gas by nearly 5% and electricity by more than 4%.

The timing of the projected peak of passenger car fuel demand growth is one of the greatest uncertainties in the transport outlook for China, although the question appears to be increasingly "when" and not "if", at least for as long as there is no reversal of current policies. In 2016, 24.4 million passenger cars were sold in China, setting a world record for annual car sales in any one country: this is equivalent to more than 10% of the total current car stock of the United States. This record-breaking level of sales benefited from supportive taxation which ceased at the end of 2016, and this change is expected to slow car sales in 2017. The current low level of car ownership of just below 120 cars per 1 000 people still indicates strong potential for future growth: in the New Policies Scenario, it rises to around 375 cars per 1 000 people in 2040, boosted by a 4.4% growth of GDP per capita per year. Car ownership, of course, could grow above this level: if it was to reach 700 cars per 1 000 inhabitants (today's level of car ownership in the United States) in 2040, then the additional 460 million cars would increase oil demand by more than 2.4 mb/d in comparison to the New Policies Scenario.

Figure 13.9 ▷ China average annual growth of passenger car fuel use and vehicle stock by region and EV share in the New Policies Scenario



Passenger car fuel use diversifies and peaks in 2030 as growth in the car stock slows in the East and Central regions and electric cars make inroads

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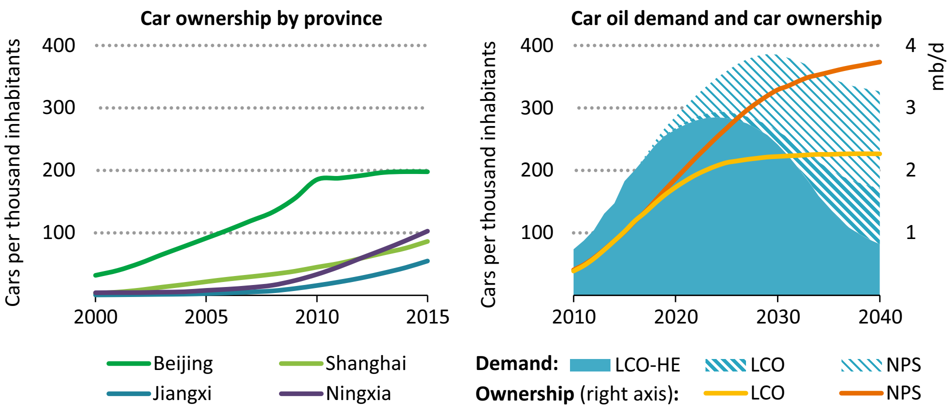
Trends in car ownership are very uneven across regions in China. Today car ownership levels vary significantly by province, ranging from 200 cars per 1 000 inhabitants in Beijing (a similar level to Argentina) to fewer than 80 cars in most Western inland provinces (a similar level to Ghana). In the New Policies Scenario, the growth of the car stock is projected to tail off in the Eastern and Central provinces, where increasing urbanisation is expected to amplify already pressing congestion and air pollution problems. Moreover, as population growth levels off, the rate of growth of the passenger car fleet slows despite rising overall vehicle ownership. Combined with a policy push to improve vehicle efficiency and to increase use of other fuels, in particular electricity, this leads to a peak in passenger car oil demand (Figure 13.9).

Figure 13.10 ▷ China passenger car ownership in selected provinces and two variations of future car ownership and oil demand



Policies to limit car ownership growth and new mobility concepts could reduce the size of China's future car market and cut oil use, especially if electrification materialises faster

Note: LCO-HE= Low Car Ownership-High Electrification case; LCO = Low Car Ownership case; NPS = New Policies Scenario.

The levelling off of growth in car ownership is already underway in some cities in China. In Beijing, for example, car ownership rose rapidly between 2000 and 2010. To deal with congestion and air pollution, a quota system for the number of cars that are allowed to be registered was put in place in 2011. There are also two lotteries, one for individuals and one for companies that allocate a "right to drive", which is non-transferable and has a duration of six months. Together, these measures have radically cut growth in car ownership (Figure 13.10). Similarly, Shanghai put in place an auction mechanism to allocate private licences to car owners as early as 1986 (Feng and Li, 2013). This kept car ownership at very low levels, below 90 cars per 1 000 people, even though Shanghai is one of the three wealthiest regions in China. The city of Guangzhou in the province of

Guangdong also set up a control system based on a combination of auction and lottery in mid-2013. It is conceivable that more provinces will follow these examples as car ownership rises. Improvements in public transportation systems, the rise of new information and communication technologies, and possible behavioural changes will also influence future developments, and this adds to uncertainty about future car ownership levels. To take an example which illustrates the scope for rapid changes, users of dynamic ride-sharing companies in China now surpass the worldwide number of ride-sharing Uber users.

To analyse the impact such factors might have on the long-term outlook for oil, we have developed two additional cases for the cities of the Central and West provinces, where car ownership is low today and where growth in car ownership is strongest in the New Policies Scenario. In 2015, there were 36 cities with more than 1 million inhabitants in the Central provinces and 37 such cities in the Western provinces: these cities are projected to have an average urbanisation rate of 72% in 2040 (up from 50% today) and are expected to see their population rise by 73% from today's level.

Box 13.2 ▷ I bike, you bike, e-bike

Two-wheelers (i.e. bikes and motorbikes) have been and remain a key mode of transportation in China. Bicycles dominated the roads of Beijing some 25 years ago until motorbikes and cars rapidly took over and turned Beijing into one of the most heavily congested cities in the world. Not every city in China has developed in the same way. Shanghai banned gasoline-powered scooters as early as 1996 to tackle air pollution and foster electric-mobility. Guangzhou, Shijiazhuang and Suzhou followed this example a couple of years later. As demand for electric bikes (e-bikes) grew, a myriad of small- and medium-size companies were created or shifted their previous activity to produce e-bikes. Smartphone applications such as Zeebike or Xiangqi further facilitated the uptake of e-bikes. Today, e-bikes represent the cheapest mode of motorised transport in China, and the market is huge: in 2016, more than 34 million electric two-wheelers were sold, a record two-thirds of all two-wheeler sales. There are more than 250 million electric two-wheelers on Chinese roads today, of which around 85% are e-bikes. They account for about 60% of transport-related electricity consumption and are estimated to have saved 30 thousand barrels per day (kb/d) of gasoline in 2016.

Even though electric two-wheelers can help reduce air and noise pollution as well as traffic jams, ten major cities, including Beijing, Shanghai and Guangzhou, have now limited or banned electric bicycles because of numerous repeated infringements of traffic laws and a rising numbers of accidents. Future regulatory regimes for e-bikes will need to consider licences, training, insurance and security features to help further development of this popular means of transport. In the New Policies Scenario, 380 million electric two-wheelers are on the road in 2040, satisfying one-sixth of road passenger mobility demand in China.

In a *Low Car Ownership case*, we assume earlier and more widespread action to limit car ownership growth in these cities than assumed in the New Policies Scenario, with the aim of combating congestion and air pollution; and we assume this takes the form of the adoption of policies along the lines of those put into action in Beijing, combined with improved urban planning, the development of mass transportation systems and an increased uptake of car-sharing concepts. This would cut China's passenger car stock to just below 320 million vehicles in 2040, 200 million vehicles less than in the New Policies Scenario, and would correspond to a nationwide average car ownership of around 225 cars per 1 000 people in 2040, i.e. more than 10% higher than that of Beijing today. Pursuit of such policies would lead to an earlier and more pronounced peak in oil demand from passenger vehicles, and oil demand in 2040 would be 1.6 mb/d lower than in the New Policies Scenario.

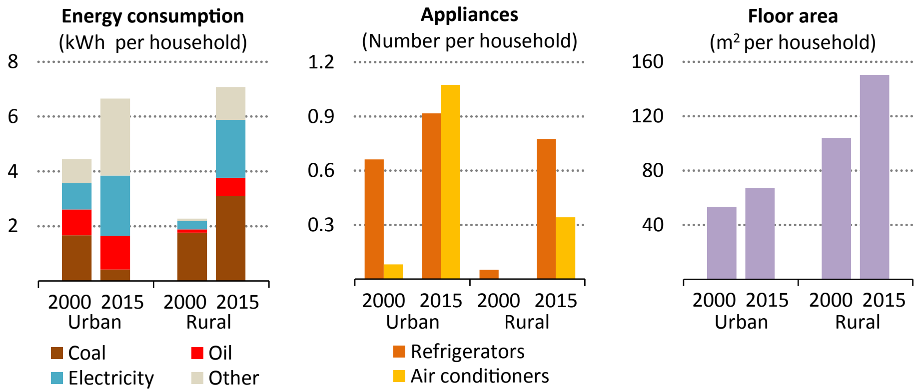
In a *Low Car Ownership-High Electrification case*, we additionally assume that the electrification of passenger vehicles develops more quickly, driven in part by the development of car-sharing concepts. Combined with the lower overall car stock, this would boost the share of electric cars in the passenger vehicle stock to 70% in 2040, compared with 20% in the New Policies Scenario, and cut oil demand by another 0.9 mb/d in 2040. The impact for the world would be very significant: global oil demand would begin to plateau as early as 2030.

13.3.3 Buildings

Background

Globally, and in many developed countries, the buildings sector is the leading source of final energy and electricity demand, representing more than half of electricity consumption. In China, however, the buildings sector accounts for only 23% of total final consumption and less than 30% of electricity demand, owing in part to the dominant role of the industry sector. Almost 80% of energy consumption in the buildings sector is in households, the remainder is in the services sector. Energy consumption patterns in residential buildings differ between urban and rural households, as in many other countries, and depend on income, climate and local fuel availability. In developing countries, energy use in rural households is often much lower than in urban areas (for example because lower income rural households have fewer appliances), and the energy may come from the traditional use of biomass. China has made great strides in bridging the consumption gap between rural and urban areas and in providing access to modern energy services. In 2000, when excluding the traditional use of solid biomass, an urban household consumed 80% more energy than a rural household, much of which was coal. Today, urban and rural households consume about the same amount of energy (excluding the traditional use of solid biomass). The fuel mix in each case remains quite different (Figure 13.11): electricity is the only energy carrier for which consumption is almost equivalent between urban and rural households, although its use varies by province. Electricity use in rural households has grown by a factor of eight since 2000 as a result of growing ownership of appliances. In urban areas, electricity demand has doubled since 2000, following a switch from fans to air conditioners and also reflecting a growing number of small appliances. Average household floor space (which drives energy use for heating and cooling as well as lighting) has grown strongly since 2000: urban dwellings have on average about half as much floor space as rural dwellings.

Figure 13.11 ▷ Average energy consumption, number of appliances and floor area per household in China's urban and rural areas



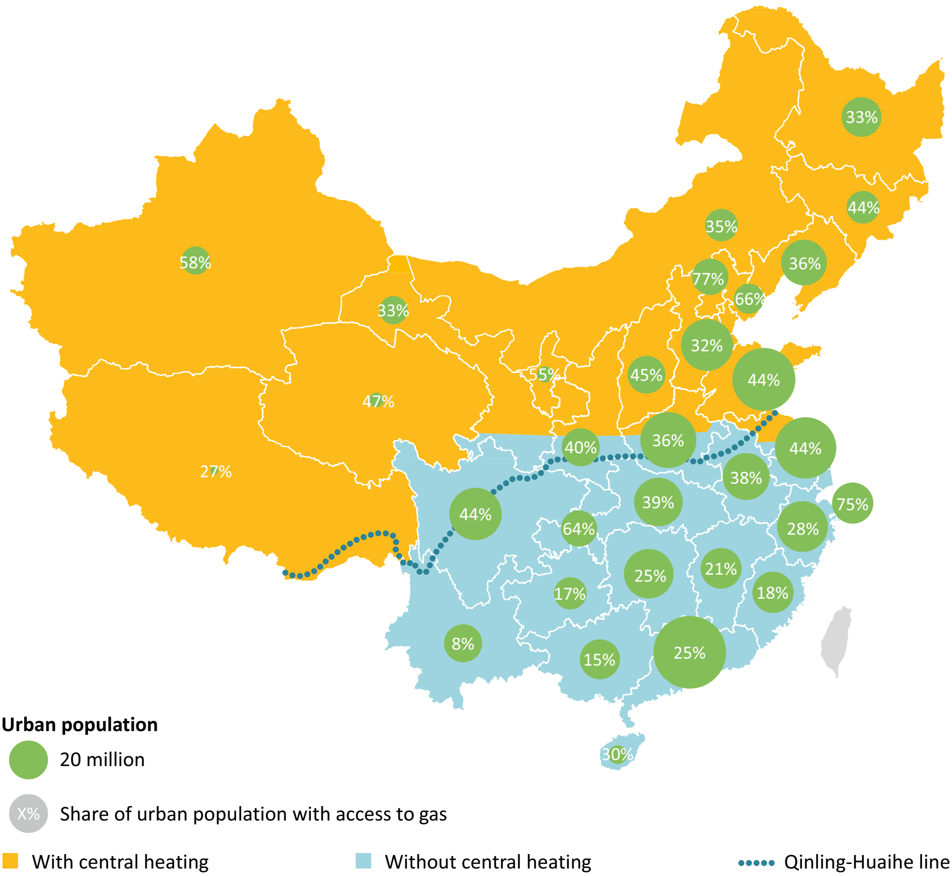
Access to modern fuels in urban areas enabled a switch away from coal, but coal still represents an important share of household energy use in rural areas

Note: Other includes solar thermal in rural areas, and gas, district heating and solar thermal in urban areas.

The difference in energy patterns between households also reflects geography and the prevalent climate, household incomes, and the affordability of equipment. In the 1950s, the Chinese government began to invest in district heating in the northern provinces of China, as temperatures are lower and winters colder than elsewhere. Today, China has one of the most extensive district heating networks in the world, which is exclusively located in the Northern and Central regions (Figure 13.12). In rural areas unable to access these networks, biomass or coal are typically used for heating: together they account for more than 40% of residential final consumption, although this is well below their share of more than 85% in 2000.

The services sector is not a large energy user today in China, but energy use is growing as the sector's value added to GDP increases: it rose from 47% in 2000 to 52% in 2016. The energy needed to produce one unit of value added in the services sector in China is 13-times lower than in the industry sector: moreover the energy intensity of the services sector has declined by 27% since 2000, which is not much less than the 31% decline

Figure 13.12 ▷ **District heating network by province and share of urban population with access to natural gas in 2015**

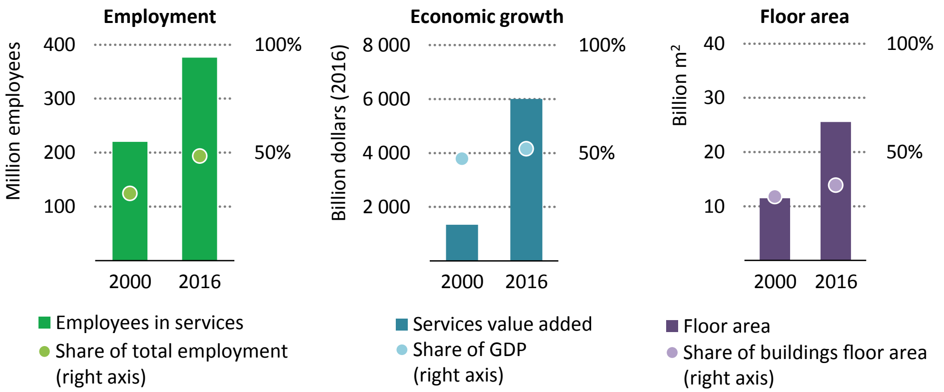


The map presents data of provinces in China.
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Significant heat demand has driven investment for district heating networks in northern provinces; southern provinces rely on other solutions, in particular electricity

registered in the industry sector. The services sector is also a growing source of employment: today, 48% of all employees in China work in services, encompassing private offices and trade as well as health and education, up from 31% in 2000 (Figure 13.13). The rising number of employees and their activity has led to higher energy consumption for heating, lighting and cooling, as the service sector's total floor area has increased by around 120% since 2000. Energy demand growth in the services sector has mostly taken the form of additional electricity: with new activities such as data centres and networks, and a growing number of air conditioners in public and commercial buildings, the share of electricity in the services sector has grown from 32% in 2000 to 40% today.

Figure 13.13 ▷ Indicators for the development of the services sector in China



The services sector is becoming an increasingly important source of economic growth and employment, which is increasing its demand for energy

Policy framework

The policy framework for the buildings sector in China has changed dramatically since 2000. China rolled out its first set of national standards for "green buildings" in 2006, although the number of projects that meet the requirements was low until recently. In 2009, there were only 20 green buildings that met the top-three qualification levels. By 2015, this number had reached nearly 4 000, with an additional 700 in 2016 for the top-two qualification levels. An instruction released by the Ministry of Housing and Urban-Rural Development (MOHURD) in the 13th Five-Year Plan regarding building energy efficiency and green building development mandates 20% greater energy efficiency than in 2015; over 40% of materials to be green; and the retrofit of some existing residential and public buildings (Table 13.6). With this standard, MOHURD expects that, in the next five years, urban areas in northern China will reduce their energy intensity by 15%, and public buildings nationally can reduce their energy intensity by 5% on average: it also expects that China will reach a 6% share of renewables in urban building energy consumption. The national Green Building Evaluation Standard is the main foundation for green buildings in China and covers a wide range of indicators that define green buildings.[5]

The use of natural gas in urban buildings has increased by more than 16% on average per year in the last 15 years, reaching more than 50 bcm today. In 2015, there were 285 million people using gas in cities and urban gas access reached around 40%. The 13th Five-Year Plan mandates increasing gas coverage within urban areas with the aim of

5. There are eight primary indicators, including energy conservation and use. There are four secondary indicators, including 1) construction and containment structure, 2) heating, ventilation and air conditioning, 3) lighting and electricity, and 4) energy comprehensive utilisation.

reaching around 470 million people by 2020. While many policies have targeted urban households, the 12th Five-Year Plan also contained a solar thermal target aimed at rural areas, and incentives to underpin it. But most of its programmes ended in 2013, leading to a slowdown of the solar thermal market.

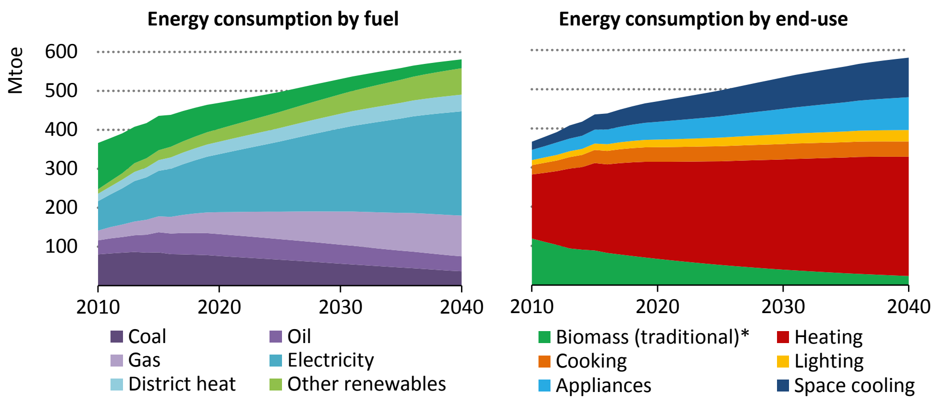
Table 13.6 ▷ Selected policies for buildings in China

Policy	Coverage	Key targets and measures
13th Five-Year Plan and related initiatives (2016-2020)	National	• Promote the construction of green buildings: by 2020, 50% of new urban residential and public buildings should meet energy conservation requirements (energy efficiency to increase by 20% compared with 2015). • Retrofit over 500 million m^2 of existing residential buildings and 100 million m^2 of existing public buildings. • Promote electricity to replace de-centralised coal and oil burning (target: electricity consumption in end-use to be 27%). • Urban gasification rate of 57% by 2020, i.e. 470 million people have access to natural gas. • Solar water heaters to cover 800 million m^2 by 2020 (almost double the 12th Five-Year Plan target). • Direct-use of geothermal: increase by an additional 200 million m^2.
China's Energy Supply and Consumption Revolution Strategy (2016-2030)	Strategic actions	• New energy promotion in rural China: improve energy consumption conditions in poor areas by developing the energy industry, setting up a commercial energy supply system (gradually enlarge the supply of electricity, gas, district heating and clean-coal and accelerate the replacement of low-quality coal), promoting the construction of electricity grids, solar PV power and heat utilisation integration.
Clean winter heating	Beijing-Tianjin-Hebei and surrounding areas	• Switch from coal to gas and from coal to electricity for 50 000 to 100 000 residences in each of the "26+2" main cities in the Beijing-Tianjin-Hebei region and its surrounding areas.
Civil Construction Energy Conservation Design Standard	National	• Heating energy use per unit area in new and refurbished buildings to be reduced by 65% in all regions, and up to 75% in specific provinces, compared to 1980-81 levels.
Ban on additional coal consumption	Provincial	• National Energy Administration banned new coal boilers for heat in several provinces.
Biomass pellet consumption target	National	• By 2020, increase the use of biomass pellets and briquettes from 8 million tonnes to 30 million tonnes (for multiple sector and heat uses).
Appliance labelling	National	• Mandatory energy efficiency labels for appliances and equipment. • Phase out of incandescent light bulbs: the import and sale of incandescent bulbs of 15 W or more was banned in October 2016.

Trends in the New Policies Scenario

In the New Policies Scenario, energy demand in the buildings sector continues to rise gradually by 1.2% on average to 2040 against the backdrop of a levelling off of population and continued rapid urbanisation (Figure 13.14). The residential sector is the main driver: it accounts for nearly 60% of total buildings energy demand growth. But energy demand from non-residential buildings, at 2.0% per year on average, grows twice as fast, reflecting the growing importance of the services sector in the economy, both in terms of its share in total GDP and in terms of the number of employees within the sector. Meanwhile rural households continue phasing-out coal and solid biomass, which improves overall energy efficiency (Box 13.3).

Figure 13.14 ▷ China buildings energy consumption by fuel and end-use in the New Policies Scenario



Energy use in buildings goes up as incomes rise and the services sector expands, and is fuelled mainly by electricity and natural gas

* Biomass (traditional) refers to the traditional use of solid biomass. It is reported separately from other end-uses as it is often used for multiple purposes (e.g. heating, cooking and lighting).

Natural gas and electricity lead the growth of energy demand in buildings. Existing government incentives to increase the use of natural gas in households and projects to extend the gas network throughout the main cities are the key drivers for an increase in gas use in buildings by around 75 bcm to 2040. The number of residential gas users today is estimated to be 285 million; the government target to reach 470 million people by 2020 is met in the New Policies Scenario. By 2040, gas consumption in buildings is around 2.5 times higher than the current level of consumption. In some big cities that are not yet connected to district heating, the use of individual gas boilers for heating purposes is rare at present, even though the population has access to gas. In the New Policies Scenario, rising incomes lead to a higher consumption of natural gas by households that are connected to a gas network, extending its use not only to cooking but also to space and water heating.

Box 13.3 ▷ Are biomass and coal disappearing from households in China?

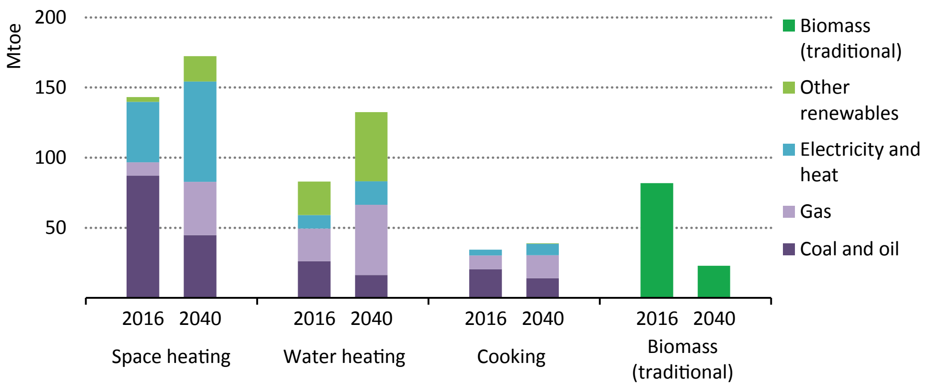
The National Bureau of Statistics of China does not release any official data on the use of non-commercial biomass, which is mostly consumed in rural areas. The IEA Energy Data Centre this year revised its historical data on the use of solid biomass in households with support from China's Tsinghua University Building Energy Research Centre (IEA, 2017). This revision has led to a reduction compared to previous estimates: our estimate of the level of traditional use of solid biomass in 2015 in China is only half the level of the estimate published in 2016. This new estimate correlates with the important increase of liquefied petroleum gas (LPG) and gas consumption by households observed during the last five years. From 2010 to 2015, consumption of solid biomass and LPG in the residential sector increased by around 60%. Efforts to increase the use of LPG and gas build on the success of previous programmes: from 1982 to 1992, China conducted the world's largest clean cooking initiative, the Chinese National Improved Stove Programme, which introduced 129 million improved biomass and coal cookstoves to rural areas, and proved to be effective. Coal consumption in the residential sector declined by 5.2% per year during the 1990s and has flattened since then, accompanied by a decline is the use of solid biomass in household energy consumption.

In the New Policies Scenario, continued strategic efforts to improve access to modern energy in rural areas help to reduce solid biomass and coal use. We estimate that around 455 million people in China relied on solid fuels for heating and cooking in 2015 and project a decline to 140 million people in 2040. The decline is achieved through an extension of district heating networks in some major towns, an increasing reliance on electricity for heat in all provinces, and a switch from LPG to natural gas in urban areas (combined with more stringent building energy conservation rules), which frees up scarce LPG supplies for households in rural areas. The decreasing use of solid fuels to 2040 occurs at a faster rate than in the last 25 years. However, as in all countries, it is the last 10% that is the most difficult to reach.

Electricity demand in buildings in 2040 is nearly 1 700 TWh higher than today, and accounts for more than 40% of China's total electricity demand growth in the New Policies Scenario. Electricity demand growth is mainly driven by higher income levels and urbanisation, but also by the growing services sector. By 2040, an average Chinese household consumes nearly twice as much as electricity as today. At 4 400 kWh per household per year, this is still 60% lower than the level of consumption in the average household in the United States, but almost 20% higher than that in Europe. The main drivers are an increasing demand for space cooling, rising levels of appliance ownership, and an additional contribution from a switch from solid fuels and oil to electricity for cooking.

Heating demand goes through an important transformation in China in the New Policies Scenario. Today, space and water heating together represent around two-thirds of buildings energy consumption, which is partly satisfied by solid biomass in rural areas in particular. The Chinese government has decided to reduce heating needs through adopting targets for green buildings. In the New Policies Scenario, this leads to a 75% reduction of space heating intensity in new residential buildings (measured in kWh/m^2). Nonetheless, space heating energy demand increases by 20% (excluding traditional biomass) by 2040 compared with today. Water heating energy demand increases by 60% from today's level, but the share of space and water heating in buildings energy consumption in 2040 remains at about the same level of today (around 50%). The use of modern fuels for cooking increases over the projection period: the 455 million people today who use solid fuels for cooking switch to improved cookstoves or modern fuels such as LPG, natural gas or electricity which are much more energy efficient (improved stoves are up to five-times more efficient than traditional stoves).

Figure 13.15 ▷ China buildings heat demand by end-use and fuel in the New Policies Scenario



Traditional biomass for heating and cooking purposes gives way to more efficient fuels to satisfy rising demand

District heating also plays an important role in satisfying heat demand (Figure 13.15). There are an increasing number of projects to extend district heating networks in the northern provinces as well as in some cities in the south which have hot summers and cold winters. In the New Policies Scenario, the use of district heating expands by 150% by 2040 from today. The use of renewables for heating, mostly solar thermal and direct-use geothermal, expands at a higher rate. In 2011, China's 12th Five-Year Plan introduced targets to reach 442 million m^2 of solar thermal. This target was reached; in 2016, China had 473 million m^2 of solar thermal heat. The target of the 13th Five-Year Plan to reach 800 million m^2 of solar thermal is reached by around 2030 in the New Policies Scenario, slightly later than expected because of the slowdown in the growth of the market in recent years. Although

China's solar thermal capacity is still the largest in the world (with more than 70% of global solar thermal capacity located in China), capacity additions actually peaked in 2013 when incentives such as "Home Appliances Going to the Countryside" came to an end. The mandatory use of solar thermal in building energy codes drives future capacity additions in the New Policies Scenario, but at a slower pace. The share of households that rely on solar thermal for water heating purposes increases to around 35% by 2040, up from an estimated 30% today. China also aims to increase space heating from the direct-use geothermal by an additional 200 million m^2, which represents a doubling of the 100 million m^2 currently installed. In the New Policies Scenario, this target is met by 2040.

One important contributor to buildings energy efficiency in the New Policies Scenario is the ambitious 13th Five-Year target to promote green buildings, which is the key policy to moderate energy consumption from the sector in the New Policies Scenario. Its importance can be gauged by looking at what would happen without this target. The additional demand that would otherwise need to be met would be likely to come mainly from fossil fuels – it is estimated that the use of coal in buildings would increase by 28 Mtce, oil by 0.2 mb/d and gas by 5 bcm. Electricity demand would also rise by 500 TWh, while the use of low-carbon energy sources would fall by 6%, relative to the New Policies Scenario. Residential cooling would use an additional 197 TWh of electricity, and space heating would account for 80% of the coal increase in 2040, reflecting the impacts of lower insulation levels (and hence higher heat demand) without the green buildings target. The share of coal in total final consumption would rise by 1.3% in response, at the expense of renewables. Insufficient initiative to achieve the green buildings target would also weigh on household energy bills: higher coal use would almost double household spending on coal. Overall, a lack of stringent building energy efficiency standards would increase annual energy consumption growth to 1.7%, up from 1.2% in the New Policies Scenario. By 2040, buildings energy use would be more than 70 Mtoe higher than with green building standards, equivalent to 2% of the country's total energy consumption in the New Policies Scenario.

13.4 Power sector

13.4.1 Background

The growth in the power sector over recent decades has been instrumental in fuelling the economic growth that has seen China become the second-largest economy in the world, and in delivering electricity access to tens of millions of people. This was built largely on a huge expansion of coal power generation capacity, which increased from 235 GW in 2000 to 945 GW in 2016 (close to half of the world's fleet of coal-fired power plants). However, renewables have begun to take centre stage: they have outpaced the capacity expansion of coal in China in each of the past four years due to strengthened policy support linked to increasing environmental concerns and falling technology costs. From 2012 to 2016, an average of 21.8 GW of wind power was added per year, 20.7 GW of hydropower (including pumped hydro) and 17.7 GW of solar PV. The rapid growth of variable renewables in recent years has exposed the challenges of their integration under current practices and market structures, which could hold back the scaling up of these technologies in China if not addressed adequately. The successful implementation of the power sector reforms that are already underway will be critical to unlock the full potential of these technologies (see section 13.4.3).

Table 13.7 ▷ Key targets of the 13th Five-Year Plan for the power sector

Category	Indicator	Unit	2010	2016	2020 target
Power supply efficiency	Coal power plants	grammes standard coal/kWh	333	314	<310
	Transmission loss rate	%	6.53	6.47	<6.5
Power capacity	Installed capacity	GW	970	1 626	2 000
	Hydropower	GW	220	332	380
	Coal	GW	660	945	<1 100
	Gas	GW	26.4	67.5	>110
	Nuclear	GW	10.8	33.6	58
	Wind	GW	29.6	148.6	>210
	Solar	GW	0.3	77.5	>110
Fuel shares*	Non fossil-fuel share in total primary energy	%	9.4	12.7	>15
	Gas in total primary energy consumption	%	4.4	5.6	8.3-10
	Coal in total primary energy consumption	%	69.2	63.4	<58

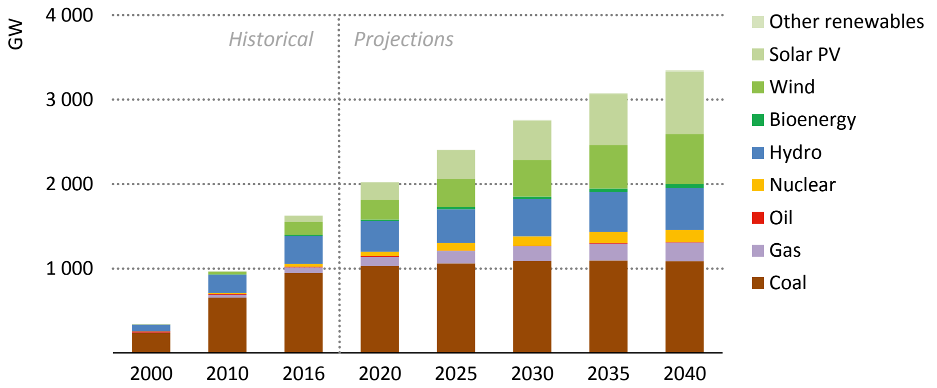
* Fuel shares in this table are expressed in Mtce terms, as published in the 13th Five-Year Plan.

In late 2016 and early 2017, China released the 13th Five-Year Plan for Electricity and Energy, which included a number of targets for the power sector for 2020. Building on progress in recent years, the 13th Five-Year Plan looks to limit the use of coal in power generation and to increase the use of natural gas, nuclear and renewables. It sets capacity targets by technology at the national level (Table 13.7). There are also targets for continued efficiency improvements in coal-fired plants, trimming losses in transmission and distribution (T&D) networks, and for diversifying fuel shares in energy use. There are broader fuel targets that impact the power sector as well, such as a target for the share of coal and gas in total primary energy demand across China's economy. The targets are translated at provincial level, which indicate a planned roll-out of renewables especially in Inner Mongolia, Hebei, Shanxi, Gansu and Guangxi. The provincial-level quotas set upper limits on deployment in certain regions, as it has been difficult to fully integrate the output of new projects to date.

13.4.2 Trends in the New Policies Scenario

In the New Policies Scenario, China's installed power generation capacity continues to expand, doubling from 2016 to 2040 (Figure 13.16). Coal-fired power plants continue to account for the largest proportion of installed capacity, but the rate of additions slows significantly and total coal-fired capacity plateaus around 2030 at about 1 100 GW. Gas-fired capacity increases rapidly in the near term before settling to slightly slower but steady growth, and total gas-fired capacity triples to over 200 GW by 2040. Low-carbon technologies grow rapidly: they overtake fossil fuels in the mid-2020s and make up 60% of total capacity in 2040. Contrary to the trend in many other countries, nuclear power capacity continues to increase: China overtakes the European Union and the United States by 2030 to become the global leader in nuclear power generation capacity, which increases from 34 GW in 2016 to 145 GW in 2040, accounting for over 40% of global nuclear capacity additions over the period.

Figure 13.16 ▷ Installed capacity by technology in China in the New Policies Scenario



Strong growth for wind and solar PV reshape the power mix in China, with low-carbon technologies making up more than half of all capacity by 2030

China has recently emerged as a global leader in renewable energy and this continues through to 2040 in the New Policies Scenario. China's power market reforms and network development directly address emerging issues, such as the curtailment of wind and solar PV output, in the near term (see section 13.4.3), facilitating further renewables deployment. Over the period to 2040, China is the largest market in the world for solar PV, wind power and hydropower, and the second-largest market for bioenergy-based power plants and other renewable energy technologies collectively. By 2040, renewables make up 57% of total installed capacity, with wind and solar PV together accounting for well over one-third of total capacity.

Continuing strong growth in recent years, wind capacity increases by an average of 20 GW per year to 2030, before steadily increasing and reaching over 35 GW a year of capacity additions by 2040 as a result of the need for re-powering ageing installations. This pace of growth quadruples the installed wind power capacity in China to nearly 600 GW, which account for close to 40% of the global wind market over the period.

Solar PV grows even faster, averaging close to 30 GW per year over the next decade, which is about one-quarter more than coal and gas combined. As with wind power, there is an increase in the growth of new capacity in the 2030s, which reflects the need to re-power ageing installations, with the domestic market for solar PV panels reaching 50 GW in 2040. Total installed solar PV capacity grows almost ten-fold and makes up more than one-third of the global increase in solar PV capacity to 2040, underpinned by China's position as the biggest global manufacturer of solar cells and modules.

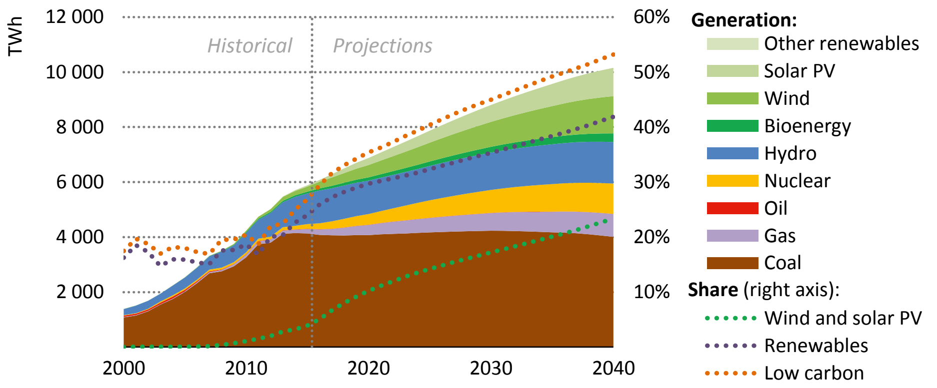
The continued development of hydropower, increasing by 50% to nearly 500 GW by 2040, provides a flexible, dispatchable source of electricity that supports the integration of rising shares of variable renewables. Pumped hydropower also adds to the flexibility of China's power system, and this energy storage technology is set to grow in the 13th Five-Year Plan from 27 GW today to 40 GW by 2020. Battery storage could also play a role in China's electricity future as costs decline, and in particular as batteries deployed in EVs become available for secondary applications. For example, with annual sales of light-duty EVs in China projected to rapidly rise from 1.8 million in 2020 to 9.5 million by 2040, 35 GW of battery capacity could be available for grid applications in 2030 alone, and almost 70 GW in 2040 alone.[6] Guidance for the development of energy storage encourages innovation through demonstration projects and supports market reforms by promoting the participation of energy storage in electricity markets.

Total electricity generation increases by 70% to 2040, an absolute increase that is nearly equivalent to the current electricity demand in the United States. Renewables grow to about two-fifths of total generation, of which slightly over half comes from wind and solar PV (Figure 13.17). Wind generation in 2040 reaches about 1 350 TWh, more than a five-fold increase from 2016, and almost equivalent to today's total annual electricity generation in India. Solar PV generation surpasses 1 000 TWh by 2040, a fifteen-fold increase from today. Together, the share of wind and solar PV in total generation steadily climbs from 5% in 2016 to 23% in 2040. About 80% of the growth in wind and solar PV generation comes from the Northwest, North and Northeast regions (the "Three Norths"), resulting in 670 TWh of net inter-regional trade as excess generation is transported to demand centres in the east. Nuclear electricity generation increases five-fold to 11% of total generation in 2040. Collectively, the share of fossil fuels declines, falling below half of electricity supply by 2040, even though gas-fired generation experiences strong growth and makes up 8%

6. Estimates assume seven years of use in vehicles and a 4% reduction (on average) in battery capacity per year of use in vehicles.

in 2040. Coal-fired generation, however, remains broadly flat through to 2040, a major departure from the trend over the past three decades, and its share drops from two-thirds of total generation today to 40% in 2040.

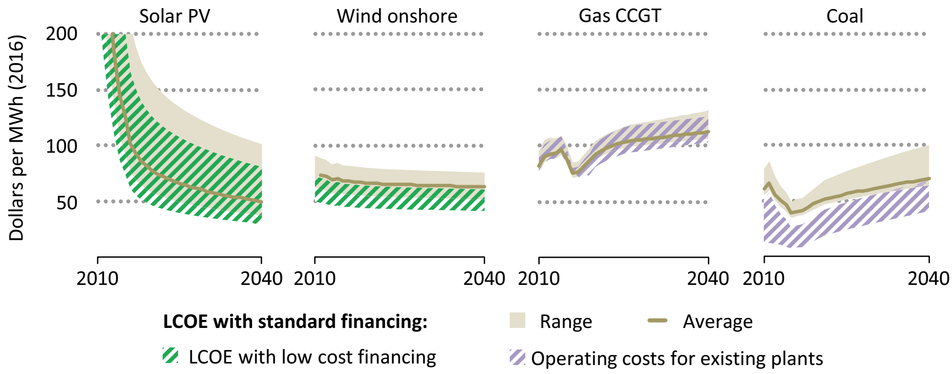
Figure 13.17 ▷ Electricity generation by fuel in China in the New Policies Scenario



Low-carbon sources of electricity generation expand to over 50% by 2040 from a 29% share in 2016

The different cost trajectories of electricity generation technologies contribute to the reshaping of the electricity supply in China. The costs of new coal- and gas-fired power plants continue to rise through the period to 2040, due to increasing fuel prices and labour costs. The levelised cost of electricity for new coal-fired power plants is currently about half that of new gas-fired capacity, but the gap narrows to 40% by 2040 as the CO_2 price increases. Renewables, however, become cheaper as increased deployment pushes down component and installation costs. The average levelised cost of electricity from utility-scale solar PV is currently over $100 per megawatt-hour (MWh) (though individual project costs span a wide range), and it is currently not cost-competitive without subsidies. Falling costs help the average solar PV project become cheaper than both new and existing gas-fired power plants around 2020, and cheaper than new coal-fired capacity and onshore wind by 2030. By 2040, solar PV costs are also lower than the operating costs of existing coal-fired power plants, making it the cheapest form of electricity generation in China. Onshore wind is already cost-competitive with gas-fired power plants: its average cost drops below the cost of new coal-fired power plants by 2035, and approaches the operating cost of existing coal by 2040.

Figure 13.18 ▷ Historical and projected levelised cost of electricity by selected technology in China in the New Policies Scenario



Solar PV becomes the cheapest form of electricity generation in China in the 2030s as costs fall while those of conventional generation rise

Notes: Coal includes subcritical, supercritical and ultra-supercritical designs. CCGT = combined-cycle gas turbines. LCOE = levelised cost of electricity. Operating costs include fuel, variable operation and maintenance (O&M) and CO_2 costs. Historical costs and capacity factors for renewables provided by the International Renewable Energy Agency. LCOEs for coal and gas CCGTs reflect projected fuel costs and a range of capacity factors (50-80%). Standard financing assumes a 7% weighted average cost of capital, and 4% for low-cost financing.

Nevertheless, while renewable technologies become progressively cost-competitive with fossil-fuel generation, the value of variable renewable technologies starts to decline as their share of annual generation increases,[7] and it becomes increasingly important to take account of network costs in determining whether variable renewables are truly competitive with dispatchable generation like fossil fuels.

In the New Policies Scenario, average power supply costs per unit of output, including capital recovery for power plants and networks, operation and maintenance, fuel and CO_2 costs, increase in China by close to 20% by 2030 (Figure 13.19). In 2016, capital recovery for past investments in power plants, particularly fossil fuels and hydropower, and network infrastructure accounted for 60% of total electricity supply costs. The strong investment in wind and solar PV in the New Policies Scenario means that the capital recovery for these projects quickly becomes one of the largest cost components of total electricity supply. Over time, however, variable costs make up a larger share of total supply costs and are the main driver of the overall increase in costs, a trend accentuated by the implementation of

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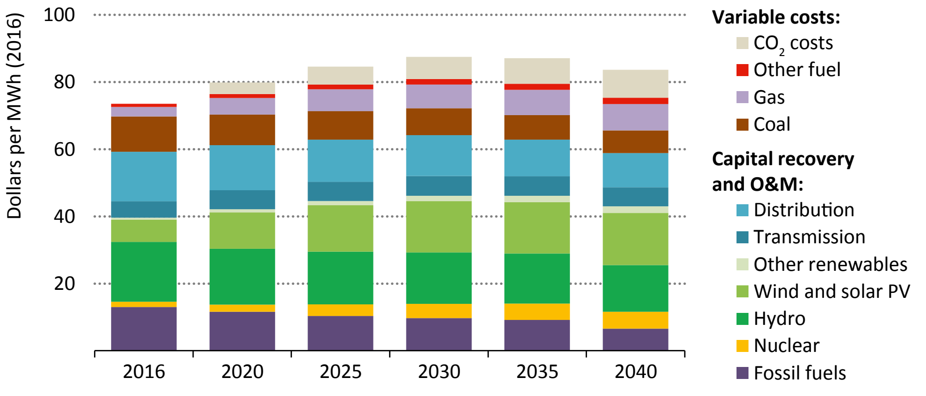
7. Value reflects the usefulness of the electricity supplied at any given time, where energy supplied when demand is high is generally more valuable to the system and low when demand is relatively low. Value can be measured in terms of market-based revenues or avoided costs. Further discussion of the value of renewables-based electricity is available in Chapter 11 of the *World Energy Outlook-2016* (IEA, 2016).

a CO_2 price. As the underlying power supply costs rise, the projected end-user prices also increase. Average electricity prices for industry increase from about $115/MWh in 2016 to $135/MWh in 2040, though not all types of industry pay the average rate. Residential prices increase more substantially, as they become more aligned with the underlying costs.

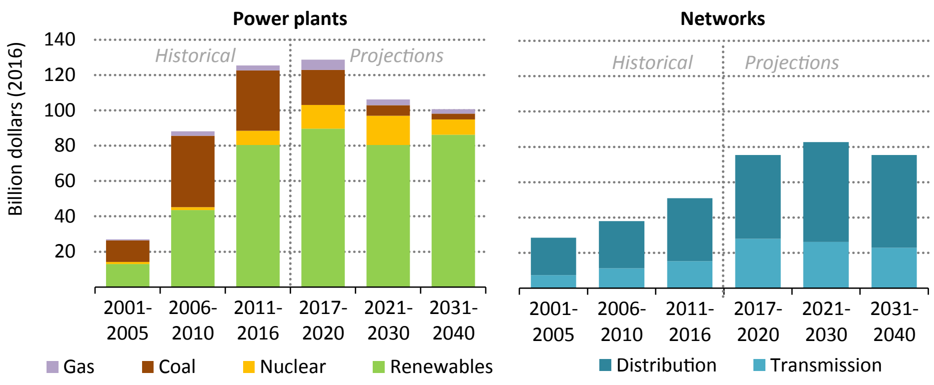
Figure 13.19 ▷ Electricity supply costs by component in China in the New Policies Scenario



Electricity supply costs are set to increase to 2030, and then decline to 2040

Investment in power plants in China has seen tremendous growth in the past decade, but the pace decreases over the period to 2040 in the New Policies Scenario (Figure 13.20). This reverses the recent trend where China had been making up an increasing share of global power sector investment, peaking at 30% in 2015. China's share drops to 25% by 2025 and below 20% by 2040. Investment in fossil-fuelled power plants declines sharply as coal capacity additions slow, dropping to just 3% of total investment in new power plants in the 2030s. Annual average investment in low-carbon technologies stays close to $100 billion per year through to 2040. To 2030, increasing investment in nuclear energy partially offsets a drop in annual investment in renewables, which largely reflects reductions in the costs of wind and solar PV. Thereafter, there is a rebound in investment in wind and solar PV to replace older installations and investment in nuclear slows. Network investments continue to grow to 2030 to meet increased demand but taper off after that: replacements of ageing network infrastructure make up an increasing share of the total network investments, and account for one-third of total network investments by 2040. Overall, investments in power plants and networks rebalance so that power plants account for less than 60% from 2021 to 2040. This marks a shift from the position in recent years, in which power plants accounted for over 70% of power sector investment from 2011 to 2016.

Figure 13.20 ▷ Annual average investment for power plants and networks in China in the New Policies Scenario



Power plant investment declines after recent boom, while investment in networks increases

The share of low-carbon technologies in China's energy mix could see faster growth than projected in the New Policies Scenario. In the Energy Production and Consumption Revolution Strategy (2016-30), China laid out a longer term vision to increase the share of non-fossil fuels in total electricity generation to 50% by 2030 and to reduce carbon intensity by 60-65% from 2005 levels by 2030. Achieving this would entail 10% less output from fossil-fuelled power plants in 2030, or 460 TWh, than envisaged in the New Policies Scenario, with that output coming instead from additional nuclear power, wind power, solar PV and other renewables. Fulfilling this longer term vision depends on establishing the means of implementation in future five-year plans, as well as successfully implementing the broad power sector reforms that are under way.

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13.4.3 Power sector reforms

China is embarking on a process of sweeping reform to its power markets, with the intention of supporting the transition to a cleaner and more efficient power system that accommodates a growing penetration of variable renewable energy. The process represents a rapid acceleration of reforms kick-started in 2002 with the "No. 5 Document", when electricity generation activities were separated from ownership of the electricity grid and China's five power generation companies were created. The current wave of reforms was initiated in 2015 under the "No. 9 Document": the reforms it outlines will be tested in selected pilot regions and then introduced progressively across the country.

Prior to the latest reforms, China's electricity system has been closely regulated by the government and dominated by a small number of companies: prices for electricity generation are set by authorities, as are the number of hours that plants can operate during the year. The majority of generation assets are owned and operated by state-owned enterprises. Generators sell power to two main grid companies, which are the single buyer and retailer of electricity within their respective control areas: Southern China Power grid (SCP) and State Grid Corporation of China (SGCC). Targets for investment needs in new power generation capacity as well as transmission expansion are also set by authorities.

The power sector reforms plan to reduce the involvement of government in several key stages of the power market, while at the same time reinforcing its supervisory and planning roles. The reforms target several key outcomes:

- Increase the utilisation of renewable energy.
- Reduce average power generation costs through competition.
- Encourage competition and offer choice in the retail market.
- Modernise the use of network infrastructure.

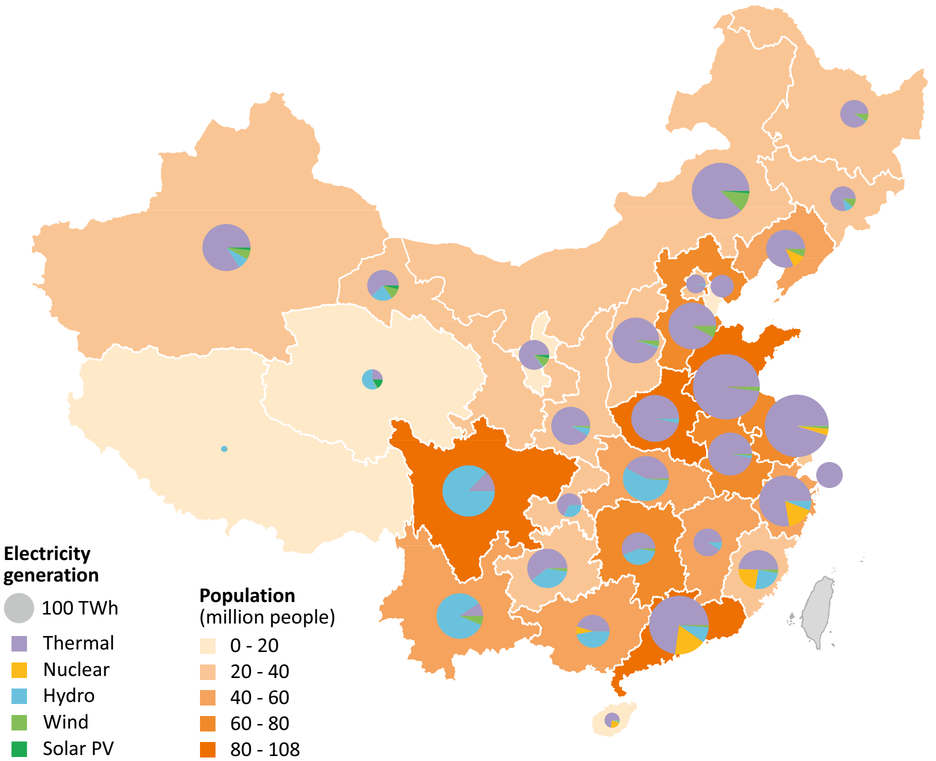
The overall aim is to bring about a fundamental transformation of electricity supply by creating a more agile and flexible power sector based on market principles to help deliver the transformation to the cleaner and more efficient energy system which China seeks.

Increasing flexibility in the power system

Across China, coal dominates the electricity mix today, representing at least half of total generation in 24 out of the 31 provinces in 2016 (Figure 13.21). Coal-fired power plants are particularly concentrated in the East and North regions of China. These two areas are home to over 530 million people, and a growing concern is air pollution largely due to emissions from coal burning in power plants, industry and households. Hydropower is the second-largest source of electricity in China today, mostly concentrated in the South and Central regions. Over half of total hydropower capacity in China is in just three provinces: Sichuan, Yunnan and Hubei. The largest hydropower facility in the world at 22.5 GW is the Three Gorges Dam in Hubei province. China is the global leader in renewables-based power generation, adding 196 GW of wind and solar PV capacity since 2010. To date, the development of wind and solar PV has been concentrated in the North and Northwest regions of China.

The development of wind power and solar PV has outpaced the ability of the power system to fully integrate the additional supply. Since 2010, total generation from wind power has increased more than six-fold, while that from solar PV has grown from near zero to about 75 TWh, doubling from 2014 to 2016 alone. However, over the same period, the curtailment of wind power has steadily increased, with smaller amounts of solar PV also lost in the past couple of years (Figure 13.22). In 2016, a total of 57 TWh of wind and solar PV generation was curtailed, nearly equal to the total power supply of Portugal. The rising curtailment of wind and solar PV is due to both market structures and technical constraints. The close regulation of power plant operations in China – notably the allocation of operating hours for power plants – misaligns the incentives of generators with the wider system goal of increasing the utilisation of renewables. In addition, the flexibility of the existing transmission infrastructure has been underutilised under previous practices. The lack of technical flexibility in the fleet of coal-fired power plants has also contributed to the rising curtailment of wind and solar PV output. Power sector reforms look to address each of these areas.

Figure 13.21 ▷ Electricity generation mix by province in China, 2016

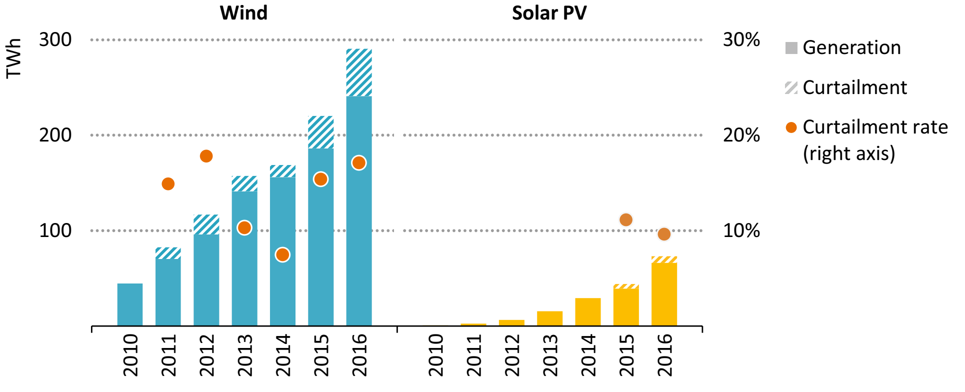


The map presents data of provinces in China.
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Thermal generation, more than 90% from coal, dominates the power mix today, particularly in the East where much of the population lives

The trade of electricity between provinces through ultra-high-voltage (UHV) transmission lines is already an important element in China's power system. China had the ability to transmit up to 140 GW of power through UHV lines in 2015, a capacity it aims to nearly double by 2020. These lines provide for the transmission of power from northern and southwestern provinces to the load centres in the east. The high-voltage network has been developed mainly in the past ten years, and includes five UHV direct current (DC) lines that are currently operating (with another slated to be fully operational in 2018) from Sichuan and Yunnan, bringing predominantly excess hydropower to the provinces of Guangdong, Zhejiang and Jiangsu. In 2016, about 41% and 45% of total electricity generation in Sichuan[8] and Yunnan[9] respectively was exported to the major load centres along the eastern coast. From provinces with available supply, such as Inner Mongolia, Shanxi and Xinjiang, the existing UHV alternating current (AC) and DC lines mainly transport electricity from fossil-fuelled power plants to Beijing, Tianjin, Hebei, Shandong and Jiangsu. There is still more electricity supply that could be transported if there was sufficient transmission capacity, especially with the ramp-up of wind and solar power. Six new UHV lines from these regions are expected to come online in 2017. Modernising the use of new and existing transmission lines will be critical to effectively integrating growing contributions of variable renewables, and will entail transitioning away from a system of scheduled power flows to one that provides a platform for dynamic market operations.

Figure 13.22 ▷ Total generation and curtailment of wind and solar PV in China



The curtailment of wind and solar PV has been increasing in recent years, as infrastructure and market reforms have struggled to keep pace with wind and solar PV's rapid expansion

In the New Policies Scenario, the power supply in China undergoes a transformation, with renewables accounting for over three-quarters of all capacity additions to 2040. Wind and solar PV lead the way, making up about two-thirds of total additions combined. The Northwest, North and Northeast regions are the focus of power sector expansion, representing about three-quarters of all wind and solar PV capacity additions, along with just over half of coal capacity additions to 2040. Coal makes up around 10% of total additions to 2040 across China, and half of those are completed by 2020. The amount of coal-fired power capacity plateaus in each region soon after plants already under construction are completed. Hydropower is further developed along the major river systems in the South and Central regions, providing flexibility within those regions.

8. Annual report of State Grid 2016, *www.sgcc.com.cn/csr/index.shtml*.

9. Annual report of China Southern Power Grid 2016, *www.csg.cn/shzr/zrbg/*.

Nuclear plants continue to be developed in the East and South regions, where plentiful supplies of water for cooling are available.

The share of renewable energy rises to 40% of total power generation in 2040 while the share of coal falls to that level from two-thirds in 2016. By 2030, wind and solar PV account for 17% of total generation in China overall, and provide over 50% of generation in the Northwest region, 20% in the North and 18% in the Northeast. Over time, coal-fired power plants shift into a different role, providing flexibility to accommodate the variable output of wind and solar PV rather than constant baseload. As a result, the average capacity factor of the coal fleet continues to decline over time: it falls from 49% in 2016 to 44% by 2030 and 42% in 2040.

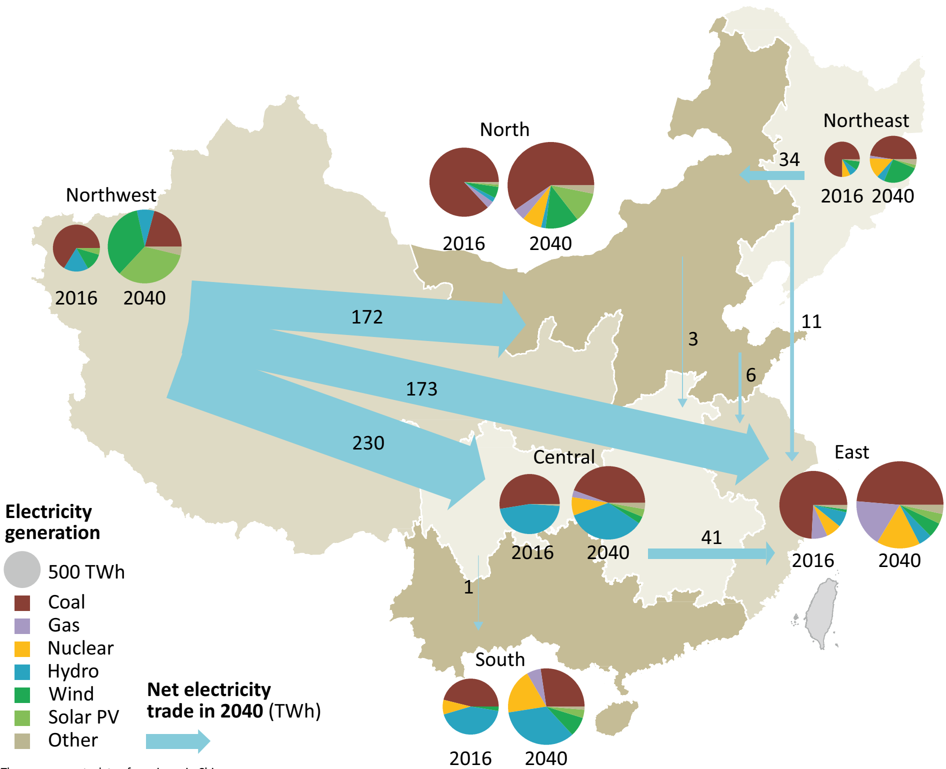
Box 13.4 ▷ Regional hourly models with electricity trade

In support of the analysis of the power sector in China, an hourly model was developed to gain insights into the operation of the power system. The model expands the capabilities of the hourly model developed for the Special Focus on Renewable Energy in the *World Energy Outlook-2016*, with the main enhancement enabling the representation of electricity trade between regions on an hourly basis. The availability of imports or exports is then considered in conjunction with the classical hourly dispatch model that sets the objective of meeting electricity demand in each hour of every day over the year at the lowest cost, given operational constraints.

For the power sector analysis, China was divided into six regions which correspond to the organisation of power system operations: Northwest, North, Northeast, East, Central and South.[10] Historical data was divided by region and projections were generated for each region through to 2040 with the World Energy Model. All 106 power plant types were represented in the model, including existing and new plants and 16 types of renewable energy technologies. Transmission capacity expansion to 2040 included all plans for new lines to be built by 2030 provided by SGCC. Power generation capacity expansion was determined in the World Energy Model, based on policy frameworks that vary by scenario, as well as priorities for regional economic development and investment. Within each projected year, the installed generation capacity by technology is then available for dispatch, subject to technical constraints for thermal power plants, such as ramping constraints and minimum operational load, and resource availability constraints for renewable energy technologies, which vary by region. The model also represents power plant flexibility, the availability of demand-side response and energy storage to balance the supply and demand of electricity. With the representation of trade also factored in, this provides a robust assessment of the structural excess of electricity in any hour, together with an estimate of the marginal price of the electricity supply in each hour in each region through to 2040.

10. This regional consideration differs from the four economic zones described in Chapter 12.

Figure 13.23 ▷ **China electricity generation mix by region and net electricity trade flows in the New Policies Scenario**

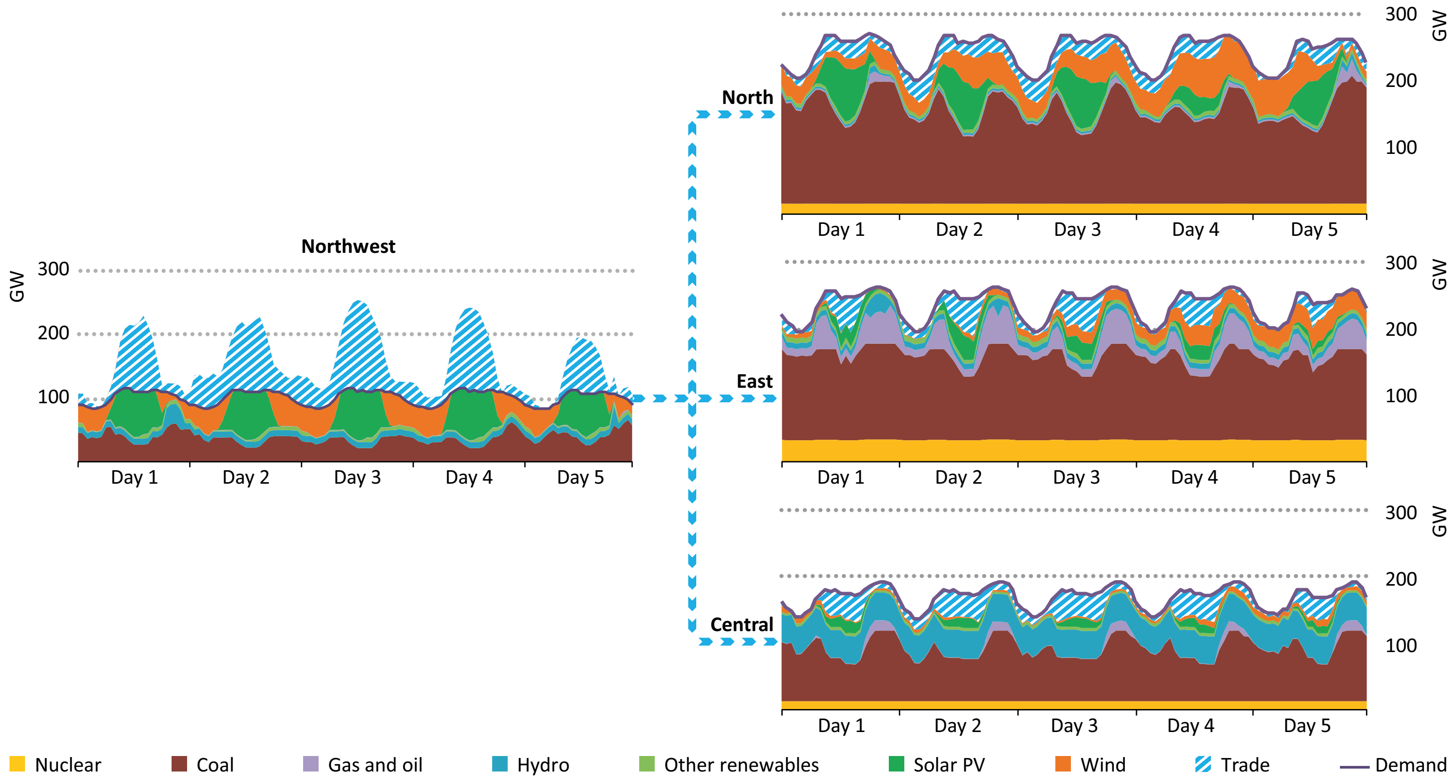


The map presents data of provinces in China.
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

The Northwest and Northeast regions become the major exporters of electricity, supplying a mix of renewables-based and fossil-fuelled generation to the East and Central regions

Continued expansion of the UHV networks enables the trade of massive amounts of electricity between regions in China. In the Northwest region, the ability to transmit 250 GW of power supports the rapid expansion of wind and solar PV capacity and helps to meet electricity demand growth in the East and Central regions. By 2040, the Northwest region exports one-third of its annual generation, helping meet around 10% of demand in both the East and Central regions (Figure 13.23). In doing so, the Northwest region provides relatively clean energy to densely populated areas. The import of this electricity in the East, where much of the population of China lives, helps reduce the reliance on coal-fired generation, lowering primary pollutant emissions in the region and improving health outcomes (Figure 13.24). The Central region also plays an important role in the balancing of electricity across China, taking advantage of the flexibility of hydropower to import large amounts of power from the Northwest region while exporting power to the East.

Figure 13.24 ▷ China hourly generation mix and electricity trade for the Northwest, North, East and Central regions in 2030



Expanded transmission capabilities provide for electricity supply and demand to be balanced across China

Coal-fired power plants represent almost 60% of total installed capacity in China today, and still represent 40% of the total in 2030 in the New Policies Scenario, making the flexibility of these assets critical to the integration of renewable energy. Currently, the flexibility provided by recently built coal-fired power plants is quite limited, but this is set to change through the encouragement of competition in electricity markets and the large programme to retrofit by 2020 about one-fifth of all coal capacity to facilitate their flexibility (Box 13.5). Market-based price signals and enhanced technical capabilities support the transition of coal to assist in integrating variable renewables. Our analysis indicates that doing so, in addition to modernising the use of transmission infrastructure, provides for the effective integration of wind and solar PV throughout the *Outlook* period and limits the amount of curtailment to less than a few percent of total wind and solar PV output through to 2040.

Box 13.5 ▷ Improving the flexibility of coal-fired power plants in China

Increasing the flexibility of the existing fleet of coal-fired power plants has been identified by the government of China as a necessary near-term step to increase the flexibility of the overall power system. China plans to continue to develop flexible new plant, including gas-fired power plants plus pumped hydropower facilities, but action to increase the flexibility of coal plants as well is critical to successfully integrate increasing shares of variable renewables and to enable China to meet its long-term climate goals. In its 13th Five-Year Plan, China commits to retrofit 133 GW of combined heat and power (CHP) and 86 GW of condensing coal-fired plants to enhance their operational flexibility and environmental performance by 2020. This represents about one-fifth of the installed coal-fired capacity of China.

China has prioritised lowering the minimum load as the first step. Through the retrofits, the aim is to reduce minimum loads by roughly half from current levels, which are generally 60-70% for coal-fired CHP plants (expressed as a share of maximum power plant capacity) and 40-50% for other coal-fired power plants. The approach also includes efforts to increase ramping speeds and shorten start-up times. Currently, common ramping speeds are in the range of 1-2% of net power output per minute, while (hot) start-up times range from three to five hours. Currently, China is operating 22 demonstration plants to study the impact of technical retrofits on its power system.

Technically, there are several measures that can be applied to increase thermal power plant flexibility, including:

- Improved combustion conditions.
- Condensate throttling to raise the speed of steam generation and improve pressure control.
- Deactivation of the steam pre-heaters to improve dispatch control and reduce minimum load.
- Integration of digital controls to enable real-time monitoring in order to operate closer to mechanical limits without risking reliability and operational safety.

Additional flexibility can also come from less complex and less expensive measures, and through changing operational practices. Gains have been made elsewhere through the use of advanced optimisation software, training programmes, and increasing collaboration between engineers, plant operators and plant dispatchers.

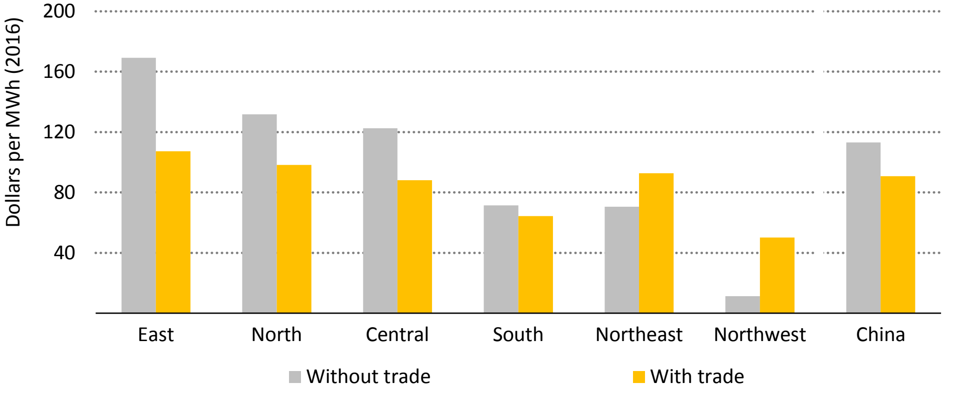
The capacity for active demand response to support the energy transition is another aim of market reform in China. The reforms mean looking at demand as a part of the system to be actively managed rather than as something fixed that just has to be passively accepted. The need for demand response, however, depends to a large extent on the state of the rest of the system. If planned transmission expansions are completed and if the flexibility of coal-fired power plants is improved as planned, demand response will have a limited role to play, but may still potentially reduce the level of investment needed in new power plants by moderating peak load. If, however, either the expansion of transmission or plans to increase the flexibility of coal-fired power plants deliver only in part, a higher level of demand response will be needed to help minimise the curtailment of output from newly constructed wind and solar PV projects.

Price reform: reflecting costs

Pricing reforms in China aim to reduce costs, prices and ultimately electricity bills for consumers by building market mechanisms and competition where possible to provide price discovery, so that prices reflect costs and so that there is no longer any need for price-setting by the government. The wholesale power generation market and the retail market are two key areas where competition may help drive down costs to consumers. Network infrastructure does not lend itself to competition, and reform here is aimed at ensuring that the costs charged to consumers directly reflect costs in the network.

In the New Policies Scenario, average power generation costs in China increase steadily over time, with rising fuel costs and the implementation of a CO_2 price through an emissions trading scheme, rising by one-quarter between 2016 and 2040. The expansion of trade in electricity between regions serves to keep down average power generation costs in China overall, balancing electricity demand and supply across an enormous area. It also has significant impacts on the average cost in each region, and therefore the average end-user price. The high-quality renewable energy resources in the Three Norths, supplemented by coal-fired power, provide cheap electricity across the country. Importing from other regions lowers average wholesale energy market prices by over one-third in the East region, compared to what they would have been without electricity trade (Figure 13.25). Average prices are reduced by roughly one-quarter in the Central and North regions. While they are raised in the Northwest and Northeast, there is a broad efficiency gain across the system that is reflected in 25% lower average market prices in 2040.

Figure 13.25 ▷ China average hourly wholesale energy market prices by region in the New Policies Scenario, 2040



Expanded trade in electricity balances market-based electricity prices across China, bringing them down significantly in the East, North and Central regions

Industrial consumers in China currently pay relatively high electricity prices, and, in effect, subsidise low prices for residential consumers. Residential end-user electricity prices are below \$90/MWh, which puts them among the lowest in the world: they are 30% lower than the average price in the United States and 60% lower than the average price in the European Union and Japan. In the New Policies Scenario, both the residential and industry end-user prices increase to 2040, as the average costs of power generation in China increase by about one-quarter from about \$55/MWh today to close to \$70/MWh in 2040. This is mainly due to the increase over time in the price of CO_2, which is assumed to reach \$35 per tonne of CO_2 in 2040. Electricity prices for industry increase by 17% to 2040, reflecting the gains of expanded electricity trade. Electricity prices to residential consumers increase more substantially over time as they become better aligned with the underlying costs of supply. However, at \$135/MWh in 2040, residential electricity prices in China are still among the lowest in the world, and less than half the average price paid in the European Union.

13.5 Environmental implications

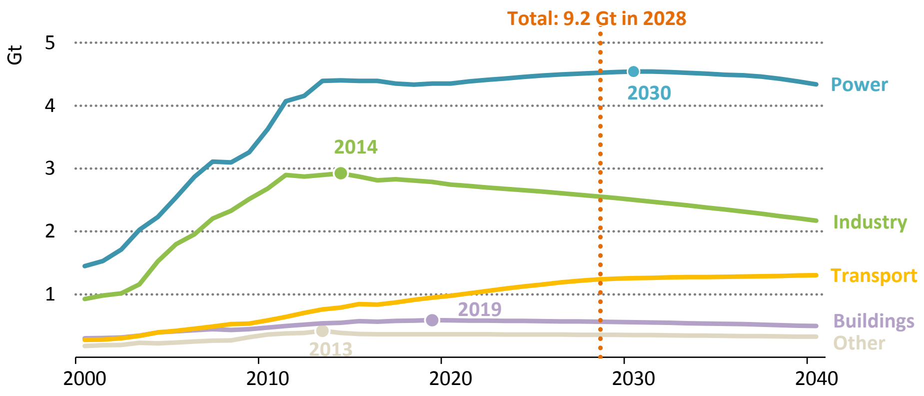
Growth in energy demand in China since 2000 has gone hand-in-hand with economic growth, but at a high cost to the environment. Today, China is the largest contributor to global energy-related CO_2 emissions, accounting for 28% of the world total, even though its per-capita emissions of 6.5 tonnes of CO_2 are still one-quarter below the average of advanced economies. Domestic environmental concerns are also pressing, as the scale and speed of China's growth has resulted in a significant deterioration of air quality in many cities, in particular in the main industrialised areas. But China's energy sector is changing rapidly

– that much is apparent from the trends of the New Policies Scenario discussed above – and China is making significant efforts to move to a more efficient lower carbon energy sector, while at the same time taking a wide range of measures to reduce air pollution.

13.5.1 Energy-related CO_2 emissions

China ratified the Paris Agreement in September 2016. It pledged to achieve a peak in CO_2 emissions by 2030 and to strive to peak sooner; reduce the carbon intensity of GDP by 60-65% below 2005 levels; increase the share of non-fossil fuels in the total energy mix to around 20%; and increase its forest stock volume by 4.5 billion cubic metres, compared to 2005 levels. Since China submitted its NDCs, the country has taken important steps towards implementation of these commitments: the relevant policies and targets, including in particular those of the 13th Five-Year Plan, are all reflected in the New Policies Scenario. Their adoption makes it increasingly likely that China's energy-related CO_2 emissions (which represent around 90% of China's total CO_2 emissions) indeed could peak sooner than 2030: in the New Policies Scenario, the peak is achieved in 2028 (Figure 13.26). The decline of CO_2 emissions following the peak is not very pronounced: by 2040, energy-related CO_2 emissions are 600 Mt (or 7%) lower than in 2028, and 340 Mt lower than today.

Figure 13.26 ▷ Energy-related CO_2 emissions by sector and peak year in China in the New Policies Scenario

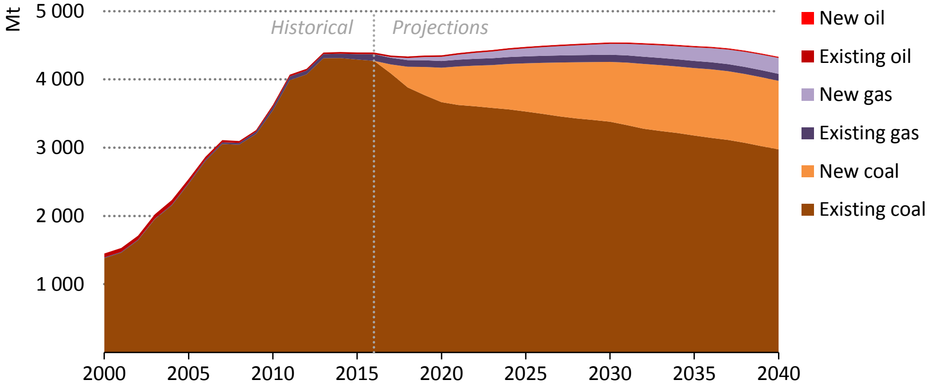


China's energy-related CO_2 emissions peak in 2028, driven by declining coal use in the industry sector; all sectors reach a peak in emissions before 2040, except transport

All sectors except transport contribute to energy-related CO_2 emissions in China peaking in 2028 and starting to decline after that date. The largest contributor is the industry sector, where combustion-related emissions are in structural decline. The declining use of coal in iron and steel as well as cement production, in line with the targets of the 13th Five-Year

Plan and the "Made in China 2025" initiative, is the main reason: CO_2 emissions from these two subsectors are 840 Mt lower in 2040 than today. Direct emissions from the buildings sector, peak in 2019: the Green Buildings standard lowers energy demand for heating, and fuel demand shifts from coal to electricity and gas as incomes rise. With the increasing electrification of end-uses, CO_2 emissions from electricity generation in China are expected to continue to increase through to 2030, albeit at a much reduced rate compared with the past one-and-a-half decades, before peaking and falling thereafter. Low-carbon capacity additions from renewables and nuclear in the New Policies Scenario broadly meet the rising demand, but the power sector remains the largest source of emissions through to 2040. About 60% of the coal fleet in place in China today (or 570 GW) is less than ten years old, and about two-thirds of total energy-related emissions in 2040 are from existing coal generation (Figure 13.27).

Figure 13.27 ▷ CO_2 emissions from the power sector in China in the New Policies Scenario



CO_2 emissions from the production of electricity and heat continue to rise to 2030 before decreasing

Only transport does not experience a peak in CO_2 emissions over the *Outlook* period. Emissions growth slows noticeably in the New Policies Scenario, mirroring oil demand trends. The slowdown in the growth of the car fleet and the large jump in the number of electric cars reduces the growth of emissions from road transport over the course of the 2030s, but emissions from trucks, aviation and shipping continue to rise.

There is no certainty about the CO_2 emissions outlook for China. It is entirely possible that emissions could peak later than 2028, or indeed earlier. But perhaps the bigger issue is uncertainty about the actual level of the peak. The future development of the industry sector, and in particular iron and steel and cement, is one key uncertainty for the level of the overall CO_2 emissions peak. A delay of ten years in reaching targets for lower production levels could raise coal demand through to 2040 (see section 13.3.1) and therefore CO_2 emissions, but would delay the overall peak in CO_2 emissions of China by only one year to 2029. The impact on the actual level of the peak is much larger: it would be 240 Mt higher than in the New Policies Scenario, which would add roughly 5 Gt of CO_2 emissions cumulatively through 2040 – more than China's current power sector emissions. Achieving an earlier peak in emissions than in the New Policies Scenario looks challenging. Lower passenger vehicle fleet growth and significantly stronger market uptake of electric cars could help achieve a peak in transport-related emissions as early as 2028 (see section 13.3.2). But the benefit for overall emissions would be limited: at around 505 grammes of CO_2 per kilowatt-hour (g CO_2/kWh) in 2025, the emissions intensity of China's electricity generation in the New Policies Scenario means that an electric car only saves 20% of emissions compared with a conventional car by that time. It would require even stronger decarbonisation of the power sector for the electrification of transport to make a meaningful contribution to the timing of China's peak in emissions.

13.5.2 Energy-related air pollution

Air quality has deteriorated in many cities across China, in particular in the main industrialised areas. The government has taken steps to address air pollution. The National Ambient Air Quality Standard, first issued in 1982, was revised in 2012 and fully implemented on 1 January 2016. It requires cities to achieve by 2030 the national standard for fine particulate matter ($PM_{2.5}$) of 35 micrometres per cubic metre (μg/m^3), which corresponds to interim target-1 of the World Health Organisation (WHO).[11] China has started publishing an air quality index, which measures $PM_{2.5}$ per cubic metre in real-time and now covers 367 cities. The "Action Plan on Prevention and Control of Air Pollution", issued by the State Council in September 2013, identified goals to improve the air quality of the entire country by 2017, while imposing stricter air pollution reduction guidelines in three key industrial areas surrounding Beijing, Shanghai and Guangzhou. Among other things, the plan pledges to strictly control coal consumption.

Nonetheless, the road to clean air in China will be long. We estimate that today only about 2% of the population has a level of exposure to $PM_{2.5}$ concentrations that complies with the WHO guideline, while around 64% of the population is exposed to levels even higher than the most modest WHO interim target-1. Almost 1 million premature deaths are attributable to outdoor air pollution today, while a further 900 thousand premature deaths are attributable to household air pollution.

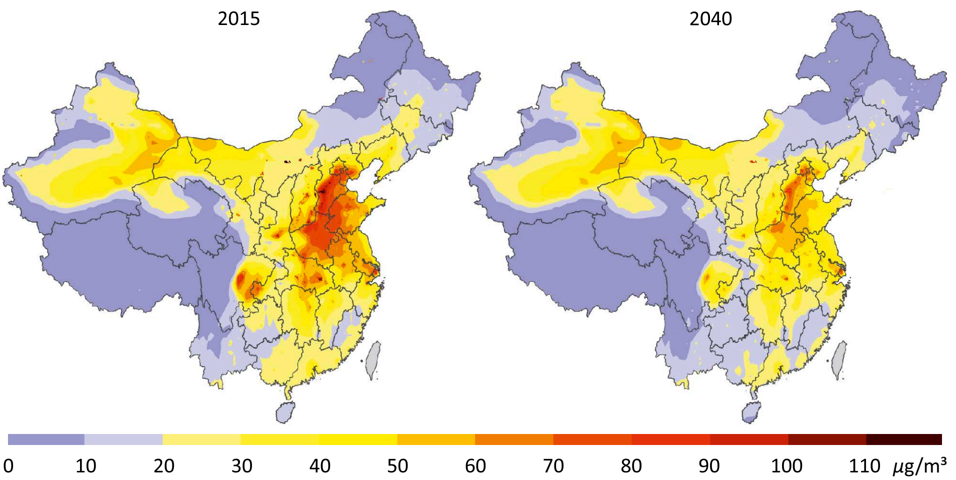
Progress is evident. According to official figures, 84 out of the 338 prefecture or higher level cities reached the national air quality standard in 2015, up from 73 in 2016. Nationwide, over the past ten years, we estimate that total SO_2 emissions fell by one-third (largely because of new pollution controls in the power sector) and total $PM_{2.5}$ emissions declined by about 25% (largely because of a shift away from biomass as a residential fuel, but also

11. The WHO air quality guideline defines a maximum concentration of $PM_{2.5}$ at 10 μg/m^3. The WHO has introduced a series of interim targets that are less stringent, but represent an attainable set of milestones towards better air quality.

new industry sector regulation). Pollutant emissions from coal combustion peaked around 2010, which marked a significant step forward. However, total NO_X emissions increased by one-third over the ten years from 2005, with 70% of this increase coming from rapid growth in road transport, driven by rising car ownership, and shipping emissions.

In the New Policies Scenario, continued efforts to reduce the impacts of energy-related air pollution on human health help to improve air quality in China (Figure 13.28). By 2040, 47% of China's population lives in areas that are compatible with the National Ambient Air Quality Standard, although only 3% of the population live in areas that comply with the WHO guideline. Household air pollution in rural areas falls as people increasingly switch to modern fuels for cooking, decreasing the associated number of premature deaths to less than 500 000 in 2040. Nonetheless, the growing number of elderly people in China means that the number of people dying prematurely from the impacts of outdoor air pollution actually rises to 1.4 million by 2040.

Figure 13.28 ▷ Concentration of $PM_{2.5}$ in China in the New Policies Scenario



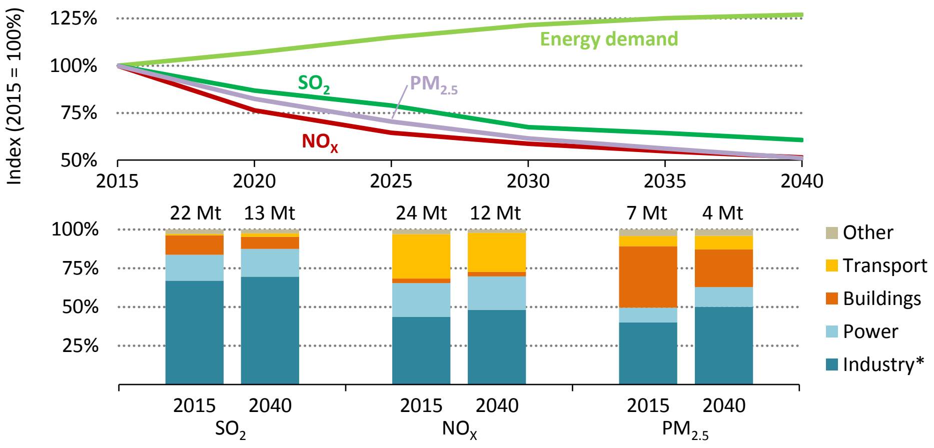
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Air quality significantly improves in the New Policies Scenario, although concentration levels particularly in industrial areas still exceed the National Air Quality Standard

Source: International Institute for Applied Systems Analysis (IIASA).

The main reason for the improvement in the outlook for air quality in the New Policies Scenario is a sharp drop of $PM_{2.5}$ emissions, which fall to about half of today's level in 2040 (Figure 13.29). NO_X emissions fall by a similar percentage and SO_2 emissions fall by almost 40%. Energy sectors efforts to moderate energy demand growth and diversify the energy mix are the main contributors, underpinned by stringent air pollution standards. In the power sector, air pollution policies are accompanied by a fall in coal consumption growth and bring down all three main pollutants: SO_2 by 35%, NO_X by 50% and $PM_{2.5}$ by about 30%. In recent years, coal-fired power generation has been a major focus of policy efforts to tackle deteriorating air quality, partly because they are major emitters, but also because many plants are located close to densely populated urban areas in China's coastal provinces. A more stringent set of emissions standards was introduced in 2012, making Chinese coal plants subject to limits that are broadly comparable with those in the European Union or the United States: for PM, the limits are 30 mg/m^3 ; for SO_2 emissions, the flue-gas concentration for new plants may not exceed 100 mg/m^3 and for existing plants 200 mg/m^3, although it can be higher in some provinces; and for NO_X, the limits are 100-200 mg/m^3.

Figure 13.29 ▷ Emissions by air pollutant and by sector in China in the New Policies Scenario



Emissions of all main pollutants fall as the energy mix diversifies and stringent air pollution standards take effect across all sectors

* Includes the transformation sector (except power and heat).

Sources: IEA; IIASA.

The industry and transformation sectors (excluding power and heat) are the largest contributors to air pollutant emissions. Combined, they emit more than half of all SO_2 and NO_X, and are the largest contributor to $PM_{2.5}$ emissions, together with the buildings sector. Emissions controls exist, but, although relatively widespread, the technologies used are often inefficient. For example, about two-thirds of coal-related $PM_{2.5}$ emissions are controlled today by basic and cheap electrostatic precipitator (ESP) devices. In-furnace limestone injection allows SO_2 emissions from about half of coal-consuming industries to be controlled, but with a removal efficiency of only about 50%. In the New Policies Scenario, more efficient technology makes significant inroads: the introduction of technologies with higher efficiency (such as advanced ESP and fabric filters) allow for more efficient control of $PM_{2.5}$, while the increasing deployment of wet flue-gas desulfurisation devices, like wet scrubbing or sulfuric acid processes, comes with a removal efficiency of about 85%. For reducing NO_X emissions, low-NO_X burners are widely adopted, as they represent the least-cost option. China's policy efforts sharply reduce air pollutant emissions from the industry and transformation sectors in the New Policies Scenario: over the period to 2040, SO_2 and $PM_{2.5}$ emissions fall by more than one-third below today's level, while NO_X emissions decline by around 45%. The total volumetric reduction of all pollutants is by far the highest in the world. For SO_2 and $PM_{2.5}$, the reductions are greater than the total amount emitted by the entire energy sector of the United States today.

In the transport sector, policy-makers have struggled to introduce measures fast enough to keep pace with the expansion in China's vehicle fleet. China's vehicle emissions control programme dates back to the early 1980s, but a modern nationwide control programme began only in the late 1990s. The effects of this are still being felt: it is estimated that about 6% of the vehicles in China do not comply with any emissions standard, and are responsible for more than 40% of road transport-related emissions of carbon monoxide, hydrocarbons (a sign of poor fuel combustion) and PM, as well as more than 30% of NO_X emissions. China has taken a number of important measures in recent years to tighten pollution standards: emissions limits for all vehicle types are now in place or being introduced over the next few years, and are among the most stringent in the world. The result is that emissions of all pollutants from transport fall in the New Policies Scenario. NO_X emissions fall by more than 50% below today's level in 2040. $PM_{2.5}$ emissions from transport fuel combustion and vehicle use drop by one-third through 2040. Efforts to strengthen fuel quality standards also help contain the rise in SO_2 emissions, despite a continued rise in oil demand.

One-third of the Chinese population continues to rely on the use of solid fuels for cooking and heating, mostly in rural areas, and this is an important source of household air pollution which is linked to 900 thousand premature deaths a year.[12] In the New Policies Scenario, the reduction in biomass and coal use for cooking and heating enables the buildings sector to cut direct NO_X emissions by half, and direct $PM_{2.5}$ and SO_2 emissions by two-thirds each. The reduction in $PM_{2.5}$ emissions plays an important role in reducing health impacts: the number of premature deaths associated with household air pollution falls by 45% to around 500 thousand cases by 2040.

12. China has indoor air quality standards for households, limiting the concentration levels of particulate matter to 150 μg/m^3, but most households exceed this limit.

Outlook for China's energy supply and investment

On the road to market?

Highlights

- With China's coal use in 2040 in the New Policies Scenario falling back to levels some 350 Mtce or almost 15% lower than those of 2016, the main challenge for the coal industry is to align its output capacity with future demand needs. Given the relatively high labour-intensity of mining, this has important social implications: direct employment in the coal industry drops from around 4 million people in 2016 to an estimate of around 750 000 in 2040. Policy-makers are actively managing the market rebalancing with capacity closures, price guidance and output cuts. Imports play a key role in this process – China again became the world's largest importer in 2016 – but the volume of imported coal declines.

- China's oil output has been falling sharply since 2015 and this proves difficult to reverse. Production falls back to 3.1 mb/d by 2040, although there is upside potential if upstream reforms succeed in mobilising new sources of capital and expertise. Oil demand increases by 35% to 15.5 mb/d by 2040 and China's dependency on imported crude oil rises to 80%. China becomes the world's leading refining centre by 2040, overtaking the United States.

- Policies encouraging greater natural gas consumption are being accompanied by a more open and market-oriented structure for gas supply, with reforms both in the upstream and network regulation. The extent to which China develops its large shale resources is a key uncertainty: in our projections, almost 100 bcm of shale output by 2040 helps total production rise to 335 bcm. This falls well short of projected demand of over 600 bcm, meaning that China becomes a major gas importer, second only to the European Union, making use of both pipelines and LNG.

- The share of low-carbon sources in China's energy mix rises from 11% in 2016 to 24% in 2040, led by the rising contribution of nuclear, solar PV and wind in the power sector, but with direct consumption of renewables for heat and mobility in end-use sectors also contributing. Hydropower remains the largest single source of renewable power in China (second only to coal in the generation mix), but wind power is projected to come close by 2040.

- China needs to invest $6.4 trillion, or an average of $270 billion each year, in energy supply to 2040 in the New Policies Scenario. The power sector, mostly low-carbon generation and networks, absorbs more than two-thirds of the total, while investment in coal-fired plants falls sharply compared with past trends. China also needs to invest more than $2 trillion in energy efficiency between 2017 and 2040, or an average of almost $90 billion per year, with spending on more efficient cars and trucks taking the largest share.

14.1 Overview of key supply and investment trends

In the New Policies Scenario, domestic market reforms, policy priorities and consumption trends, resource endowments and costs, and a range of interactions with international markets and technology developments all reshape the supply side of China's energy equation to 2040. China's total fossil-fuel output is broadly similar in 2040 to today (meaning that China remains the world's largest producer of fossil fuels, although the gap with the United States narrows). However, the composition shifts: coal output moves slightly downwards; oil output moves downwards a little more sharply; and the production of natural gas rises as China steps up exploitation of its large unconventional potential. As China's energy mix diversifies, there is also a three-fold increase in production from nuclear and renewables. Cumulative investment in China's energy supply to 2040 is almost $6.4 trillion, more than two-thirds of which is required in the power sector. Cumulative demand-side investment in energy efficiency totals $2.1 trillion.

Table 14.1 ▷ Primary energy production in China in the New Policies Scenario

	Unit	2000	2016	2025	2030	2035	2040	2016-2040	
								Change	CAAGR*
Coal	Mtoe	714	1 761	1 814	1 802	1 753	1 657	-104	-0.3%
	Mtce	1 019	2 516	2 592	2 575	2 504	2 367	-149	-0.3%
Oil	Mtoe	163	203	173	156	150	144	-59	-1.4%
	mb/d	3.3	4.0	3.5	3.3	3.2	3.1	-0.9	-1.1%
Natural gas	Mtoe	23	113	165	191	217	243	130	3.2%
	bcm	27	137	222	261	298	336	199	3.8%
Nuclear	Mtoe	4	56	166	218	261	287	232	7.1%
Renewables	Mtoe	220	269	379	453	533	618	349	3.5%
Hydropower	Mtoe	19	102	108	117	125	130	28	1.0%
Bioenergy**	Mtoe	198	112	130	148	168	190	79	2.3%
Other renewables	Mtoe	3	55	141	189	240	297	242	7.3%
Total production	**Mtoe**	**1 124**	**2 401**	**2 697**	**2 821**	**2 914**	**2 949**	**547**	**0.9%**
Total demand	Mtoe	1 154	3 039	3 480	3 679	3 796	3 858	819	1.0%
Share of imports	%	3%	21%	23%	23%	23%	24%		

* Compound average annual growth rate. ** Includes the traditional use of solid biomass and modern use of bioenergy.
Notes: Mtoe = million tonnes of oil equivalent; Mtce = million tonnes of coal equivalent; mb/d = million barrels per day; bcm = billion cubic metres.

There is no dramatic change in China's overall dependence on imports, the share of which in total demand edges slightly higher to 24% in 2040, from 21% today. The rise in output from nuclear and renewables represents a major increase in indigenous energy production, but oil and gas imports grow. China is projected to remain an importer of coal throughout the period to 2040, although at lower levels than today. The increase in import requirements for oil and gas means that, by 2040, almost 30% of the oil traded internationally is making its way towards China, and likewise almost one-quarter of the gas traded over long distances.

14.2 Coal

14.2.1 Market structure and regulation

The Chinese coal industry is fragmented and diverse. Despite many recent closures, China still has around ten thousand coal mines. These include some of the world's largest and most efficient mines, but the vast majority are small-scale operations, often using basic technology and – despite some major improvements lately – having poor safety records. Large-scale operations account for over 40% of total coal production while small mines still account for over a quarter of the country's output.

In a similar way, there is a wide range of companies involved in China's coal industry, from thousands of tiny businesses to huge coal mining firms mostly controlled by the state at national or provincial level. The twenty largest coal companies in terms of production together account for some 60% of coal output and are all state-owned. Private ownership in China's coal industry is not uncommon, although with a few exceptions (notably Yitai, the largest private coal firm) most private companies tend to be relatively small. Vertical integration is not uncommon in large coal companies. For instance, China's largest coal company (and the second-largest in the world after Coal India) is the state-owned Shenhua Group, with around 420 million tonnes (Mt) of production per year: it also runs over 50 gigawatts (GW) of coal-fired power plant, is active in coal-to-liquids production, and operates its own railway network. Similarly, China National Coal Corporation, which produces 170 Mt of coal each year, also has important interests in the coal-to-chemicals business.

Regulation, pricing, costs and profitability

Coal pricing has been fully deregulated since 2006. There is no single coal price for the entire country, but there are three key price indicators, which are typically highly correlated. The first is the Shanxi mine-mouth price (sometimes referred to as Datong price index), which mirrors the market dynamics at the heart of one of China's most important mining regions. The second is the South China delivered price, which is watched closely by exporters around the world because it determines whether coal shipments to China are profitable or not. The third is the Qinhuangdao free on board price,[1] which has become the most important price index in coal trade, not only because of the huge coal volumes it reflects but also because it reflects a combination of the forces of the domestic market and those of the international market.

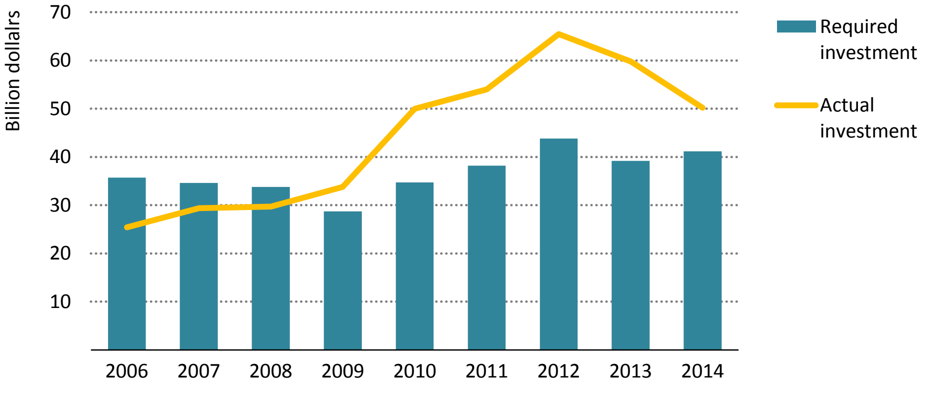
The introduction of market-based pricing in 2006, booming coal demand and tax changes, together led to a steep increase in prices and coal mining profits. These developments also led to China switching from being a net exporter of coal to a net importer in 2009. In southern coastal China – the region that is furthest away from the domestic mining hubs – coal imports became cheaper than domestic coal, leading to an influx of Indonesian, Australian and Russian coal. However, in early 2012 the price dynamics gradually started to reverse as China's coal demand growth started cooling down and it neared what was to

1. Qinhuangdao is one of the largest coal ports in the world located in northeast China in the so-called Bohai rim (also referred to as the North 4 ports region with Qinhuangdao, Huanghua, Tianjin and Tangshan ports).

become its peak in 2013. Since then, coal prices have declined for four consecutive years, reaching a point in early 2016 that was less than half of peak prices in 2011.

Between 2006 and 2012, while coal demand in China was shooting upwards, annual coal mining investment in China more than doubled to $65 billion, and production grew by 40%. At the height of the surge in investment in 2012, China invested 50% more than would have been needed to satisfy demand (Figure 14.1). When demand subsequently slowed, the effect of this surge in output capacity was to create a huge overhang of supply. We estimate that by 2015 excess mining capacity totalled up to 1 500 million tonnes per annum (Mtpa), greater than the total mining capacity of the United States, the world's second-largest coal producer.

Figure 14.1 ▷ Investments required versus investments actually made in coal mining in China



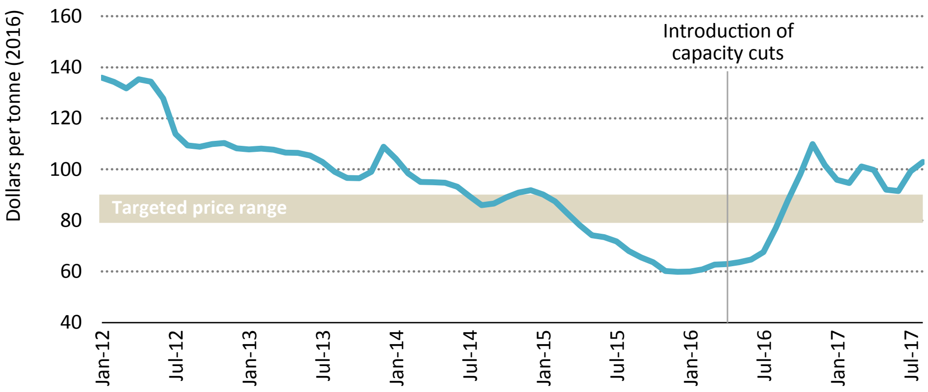
At the height of the investment bubble in 2012, 50% more capital was invested than was needed to satisfy demand

The drop in prices that resulted from this overcapacity hit the profitability of the coal industry in China. Between 2006 and 2011, when coal prices in China were rising, coal producers focussed on ramping up production, neglecting cost discipline. As a result, average mining costs increased by more than 50%, putting producers in a tight corner when prices started dropping in 2012. Since then, dwindling profitability has forced producers to bring down costs, but the 15% drop in average mining cost achieved between 2012 and 2016 was not sufficient to offset plummeting prices. By 2015, the situation had deteriorated to the point that 80% of the coal firms in China were operating at a loss. In terms of tackling costs, perhaps the main challenge now for the China's coal industry is how to raise its low overall labour productivity. Productivity varies widely across the coal industry, with some large operations achieving world-class results, but a Chinese miner produces on average less than one kilotonne of coal per year – a fifth of what a South African or Indonesian miner produces and less than a tenth of the annual output of a miner in Australia.

Need for restructuring

Faced with the combination of overcapacity and dwindling profitability, policy-makers had to choose between letting market forces lead the adjustment process in the coal sector and rebalancing the market actively with state intervention. A market-based rebalancing would have risked large layoffs as well as a possible financial crisis, since many coal companies had large outstanding loans, so the Chinese authorities chose to introduce a set of measures to cut capacity and manage production. Around 290 Mtpa of mining capacity (mostly small or idle mines) closed in 2016, but the most effective measure taken was the reduction of annual working days from 330 to 276 (Figure 14.2). Introduced in April 2016, this reduced production by up to 15%, propelling coal prices upwards by some 50% within four months.

Figure 14.2 ▷ China domestic coal price evolution 2012-2017*



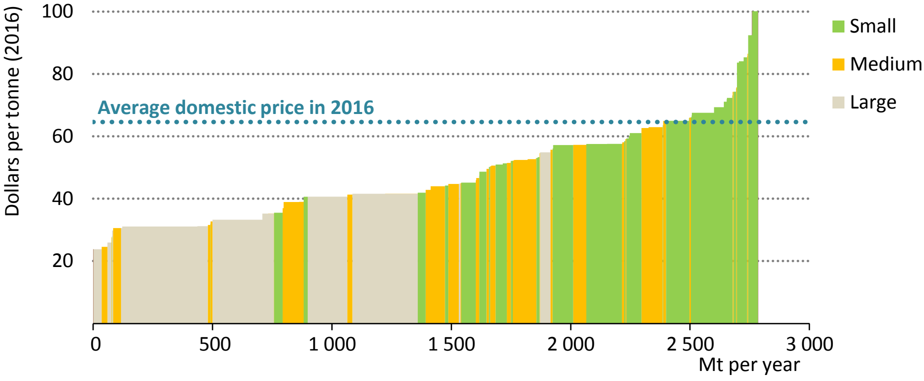
Cutting annual working days in the coal industry reduced production by up to 15% and resulted in a price rally in the second-half of 2016

* IHS monthly average coal and petcoke prices (Qinhuangdao Domestic, 6 000 kcal/kg).

The National Development and Reform Commission (NDRC) subsequently announced a set of measures – among them temporary exceptions from the 276 working days rule for the most efficient mines – that could be used flexibly to keep prices stable. From the perspective of Chinese authorities, a range of $80-90/tonne[2] appears to strike the right balance, with prices in this range being broadly acceptable to the power generators and industrial coal consumers while providing a sufficiently high margin for most coal companies to stay in business.

2. The targeted bandwidth is yuan renminbi 500-570/tonne (5 500 kilocalories per kilogramme [kcal/kg]) at the Bohai rim (e.g. Qinhuangdao and other ports in that region). Depending on how much prices exceed or fall below this range the NDRC has announced different measures that could be implemented to stabilise prices. These include the working day rule but also the approval of new mining capacity or additional closures.

Figure 14.3 ▷ **China domestic steam coal production cost curve by mine size, 2016**



China's many small mines are high cost and often have poor safety records, and are the primary target of the coal industry restructuring and consolidation policy

Sources: CRU Thermal Coal Cost Model (2017); IEA analysis.

Policy-makers have set the target of closing another 150 Mtpa of mining capacity in 2017, while the 13th Five-Year Plan envisages the gradual phasing out of small mines (especially un-mechanised mines and operations that have a bad safety record or negative environmental impacts) over the coming five years (Figure 14.3). Even as policy-makers focus on capacity cuts, however, additional production capacity is still coming on line. Over the next five years, some 40 new mining projects with a combined capacity of 250 Mtpa are set to enter the market. Another 190 Mtpa of mining capacity received partial approval and could begin production within the next few years. If all of these projects were to come to fruition, the new additions would fully offset the capacity closures achieved in 2016 and 2017.

Prospects for reform

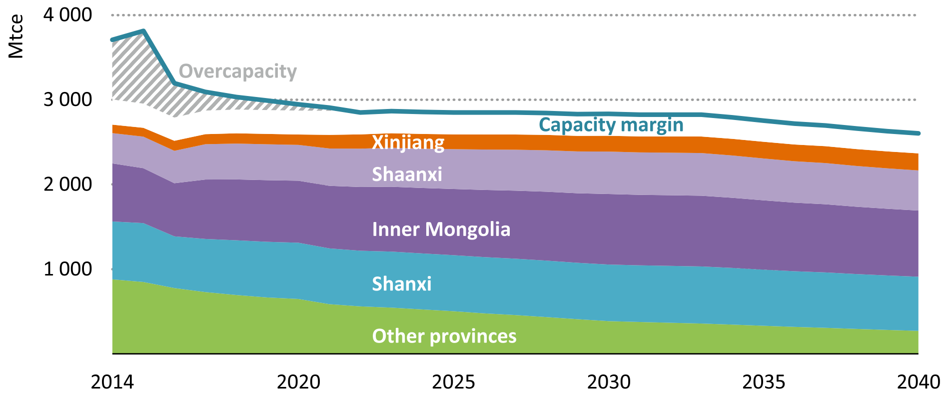
The coming ten years will see crucial decisions on measures that are needed to rebalance China's coal market, and what happens is critical for our projections of costs, production and imports. Restructuring a very heterogeneous industry that employs around 4 million people is an enormous challenge, and policy-makers have the difficult task of somehow striking a balance between capacity closures, job losses and a price level that is acceptable to both consumers and producers. Regional and local considerations will be very important, especially where coal accounts for a large share of provincial tax yield or where coal mining is central to the direct and indirect economic fortunes of entire towns and cities. The restructuring and consolidation of the coal industry forms part of a wider set of economic reforms that targets the reduction of overcapacity in various heavy industrial sectors: coal industry restructuring is thus not an isolated policy task but has many interdependencies with measures taken in other sectors, for instance, reforms to electricity pricing and the steel industry.

Coal industry restructuring has taken place in much of western Europe in recent decades, and experience there shows how painful and protracted it can be. Our *Outlook* for China rests on four key assumptions:

- Economic reforms to cut capacity in the heavy industries are implemented without undue stress in labour and financial markets.
- Policy-makers administer a gradual rebalancing process during which high-cost and unsafe coal mining capacity is successfully closed.
- During the adjustment process, coal prices continue to be influenced by state interventions and remain between $80-90/tonne.
- From the mid-2020s, when the coal market has fully rebalanced and power price reform has been successfully implemented, coal pricing fully reverts to market-based principles.

In our projections, the Chinese coal market has more or less shed excess capacity by the mid-2020s and the installed capacity operates at an average utilisation of around 90% (Figure 14.4). The capacity then in place is much more productive on average than today's mines. Over the last ten years, productivity in coal mining has increased by around 4% per year on average, and we project productivity growth to accelerate to 6.5% per year on average over the next 25 years. Over the next ten years, however, we project productivity improvements that exceed the previous average quite significantly, on the basis that many of the measures taken to reduce overcapacity will primarily affect small inefficient mines.

Figure 14.4 ▷ Coal industry restructuring: production by selected province in China and mining capacity in the New Policies Scenario



By the mid-2020s, most of the capacity cuts are achieved and the installed capacity operates at a 90% utilisation rate

Note: Mtce = million tonnes of coal equivalent.

Sources: IEA analysis; CRU Group databases.

The combination of mine closures, productivity improvements and declining production implies a significant reduction in employment in the Chinese coal industry over the *Outlook* period. Direct employment in the coal industry drops from around 4 million people in 2016 to an estimate of around 750 000 in 2040. On average, this implies that 135 000 miners are made redundant or retire every year through to 2040, with a higher figure in the first-half of the period as this is when anticipated reductions in capacity are concentrated.

14.2.2 Outlook for coal

Summary of demand trends

As described in detail in Chapter 13, the government's efforts to shift the orientation of the economy from heavy industries towards the services sector continue to shape the outlook for the coal market. China's coal demand drops by almost 15% from 2 800 Mtce in 2016 to 2 440 Mtce in 2040 (Table 14.2). Coal is the fuel of choice in heavy industries, particularly in cement and steel making, and thus heavily exposed to developments in these sectors. Cement and steel making together account for a quarter of coal consumption in China today, but this share drops by half over the *Outlook* period. Coal demand in industry, which peaked in 2014, drops by 20% to 900 Mtce in 2040. Chemicals production is the only exception: coal consumption in this sector grows nearly two-and-a-half times, with most of the increase coming from coal conversion projects.

Table 14.2 ▷ China coal demand, production and net trade in the New Policies Scenario (Mtce)

	2000	2016	2025	2030	2035	2040	2016-2040	
							Change	CAAGR*
Demand	955	2 796	2 726	2 676	2 576	2 437	-358	-0.6%
Power generation	477	1 489	1 477	1 490	1 465	1 406	-83	-0.2%
Industry	348	1 106	1 072	1 028	972	911	-195	-0.8%
Production	1 019	2 516	2 592	2 575	2 504	2 367	-149	-0.3%
Steam coal	906	2 001	2 115	2 136	2 100	2 004	3	0.0%
Coking coal	113	512	447	400	357	307	-204	-2.1%
Net imports	58	-196	-134	-102	-72	-70	126	-4.2%

* Compound average annual growth rate.

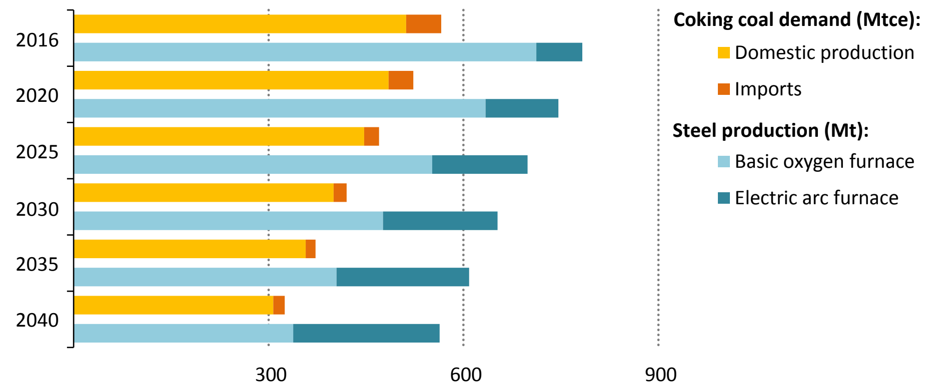
China has made significant progress in power sector diversification: in 2016, it added 34 GW of solar, 19 GW of wind, 13 GW of hydro and 5 GW of nuclear to the system. Nonetheless, low-carbon sources of power generation do not fully keep up with projected power demand growth of 2.3% per year, meaning a slight increase in the use of coal-fired plants in the period to 2030. After 2030, power sector coal demand goes into decline and reaches 1 400 million tonnes of coal equivalent (Mtce) in 2040, lower than today. By 2040, coal accounts for around 40% of power generation, down substantially from 67% in 2016.

Production prospects

In the *Outlook*, coal production in China decreases from just over 2 500 Mtce in 2016 to 2 370 Mtce in 2040. Production of steam coal, which accounts for the vast majority of China's coal production, declines slightly: the prospects for domestic production are helped somewhat by a shift in demand away from coastal areas and towards inland regions where domestic coal is more competitive, allowing Chinese coal companies to back out imports (see section on imports). The story, however, is different for coking coal, production of which declines by around 40% over the coming 25 years.

The declining fortunes of domestic coking coal producers are tied to the outlook for China's steel industry. China currently produces some 800 Mt of crude steel, accounting for half of global production, but output drops below 600 Mt by 2040, as domestic steel needs decline and other countries become more competitive in steel making. Another important trend that weighs on coking coal production is the way that steel is produced: with growing availability of scrap, electric arc furnaces gain market share at the expense of basic oxygen furnaces and this reduces the demand for coke. In our projections, the share of steel produced in basic oxygen furnaces drops to 60% in 2040 from over 90% today. There are few export opportunities available to compensate for reduced domestic demand: Chinese coking coal exports cannot compete with Australian, Canadian or Mozambican coking coal in India, the largest growth centre of the international coking coal trade.

Figure 14.5 ▷ China's coking coal demand by source and steel output by production route



A declining share of basic oxygen furnaces in China's steel production reduces coking coal demand

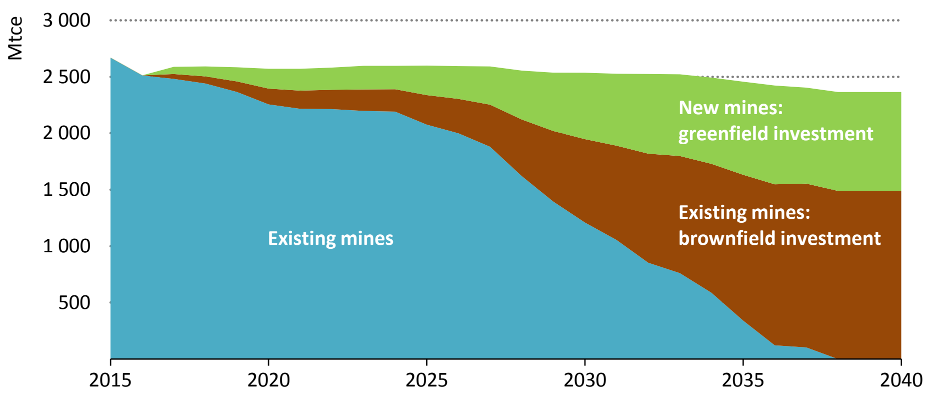
Note: Mtce = million tonnes of coal equivalent.

Currently over 80% of China's coal production comes from underground mines (depths of 700-1 000 metres are not unusual), a much higher share than in most other major coal producing countries. We expect this share to remain relatively stable over the

Outlook period. Although most of the smaller mines that will be shut in coming years are underground mines, the development potential for surface mines is very limited: with the exception of Xinjiang and Inner Mongolia, most new projects (especially brownfield projects) are underground. The high share of underground mining gives Chinese coal companies a particularly high exposure to labour cost evolution, and to a degree, to industrial power prices (machinery in underground mines runs on electricity).

A new challenge comes into view with completion of the rebalancing of the Chinese coal market in the mid-2020s. The mines that came into operation when coal demand soared during the first decade of the 2000s near the end of their lifetime between the mid-2020s and the mid-2030s, and massive reinvestments are required in new capacity to counter this, even though coal production has entered decline by then. A little over 60% of the reinvestment (in terms of capacity) occurs in operational mines, i.e. brownfield projects, while the remainder goes to greenfield mines (Figure 14.6). A long-term increase in coal prices also supports new investment. Cumulative capital expenditure in coal supply over the coming 25 years amounts to just over $380 billion, with almost $350 billion invested in mining and $30 billion in infrastructure.

Figure 14.6 ▷ China coal production by mine type in the New Policies Scenario



Coal production from existing mines falls away sharply in the late 2020s, requiring strategic choices about reinvestment in China's coal production capacity

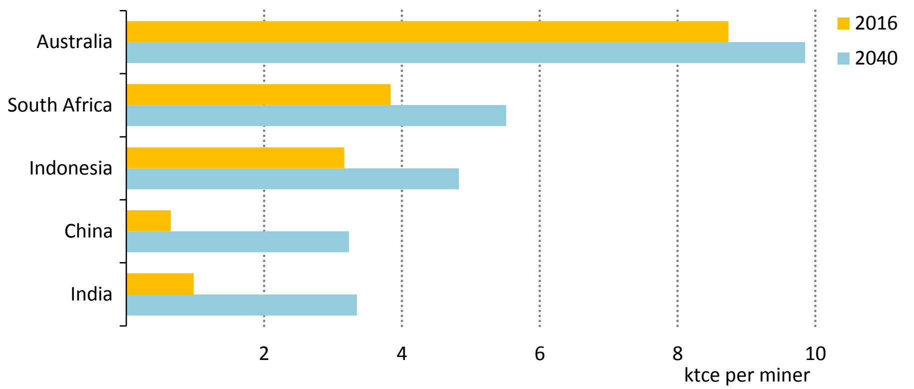
Note: Mtce = million tonnes of coal equivalent.

China's coal import requirement

Chinese coal imports have been volatile since peaking in 2013 at 250 Mtce, and they unexpectedly increased by 30% in 2016 as measures to curb capacity led to periods of temporary shortage and price spikes, requiring imports to fill the gap. China's coastal rim has become of pivotal importance for coal exporters around the world, as this is where Chinese consumers arbitrage between domestic and imported coal. This implies that the cost of delivering additional domestic supply to China's southern coast functions as a price ceiling for internationally traded (steam) coal. This situation persists in our projections despite a decline in Chinese imports from 195 Mtce in 2016 to 70 Mtce in 2040.

Our projections are subject to considerable uncertainties. With less than 10% of coal demand, imports are a relatively small item in China's coal supply balance and are very sensitive to fluctuations in the domestic coal market. How Chinese imports evolve in the first-half of the projection period primarily depends on how policy-makers manage to implement the rebalancing of the sector: frequent policy adjustments, and consequent price volatility, would translate into strong variations in imports; a smoother process would lead to a much more stable flow of imported coal. Over the longer term, once the rebalancing is more or less complete, the prospects for imports depend on whether the price of Chinese coal is higher or lower than that of imported coal. Although the Chinese coal industry is projected to become leaner and more efficient because of the restructuring process that lies ahead, we believe that most domestic coal supply is likely to remain costlier than imports in southern coastal China (see page 229 in the *WEO-2016*).

Figure 14.7 ▷ Coal mining productivity in selected countries



China's coal mining industry improves its productivity, but it remains lower than in many other major producing countries

Note: ktce = thousand tonnes of coal equivalent.

In our projections, China remains a net importer of coal, but a switch to a net export position is also conceivable. What would it take for this to happen? One possibility is that hesitant implementation of capacity cuts could led to an aggravation of overcapacity which, perhaps in combination with a faster than expected decline of domestic coal demand, could lead to exports becoming a relief valve for a distressed coal industry. As outlined in the *WEO-2016*, this could appeal to Chinese authorities if the losses from coal exports outweigh the avoided social costs such as unemployment benefits. A second possibility relates to the rate of productivity improvement in China: a major factor that keeps domestic coal costlier than imported coal on the coast is that domestic coal mining productivity remains below that of key exporters in the international market (Figure 14.7). A faster improvement in productivity could move costs to a level that pushes out coal imports and potentially also leads to exports to nearby coal markets such as Japan or Korea. Whatever the circumstances, Chinese coal exports would have a huge impact on international markets, keeping prices low for much longer than would otherwise be the case (although it could be argued that many Chinese mines would struggle to recover even their operational costs under these circumstances).

14.3 Oil

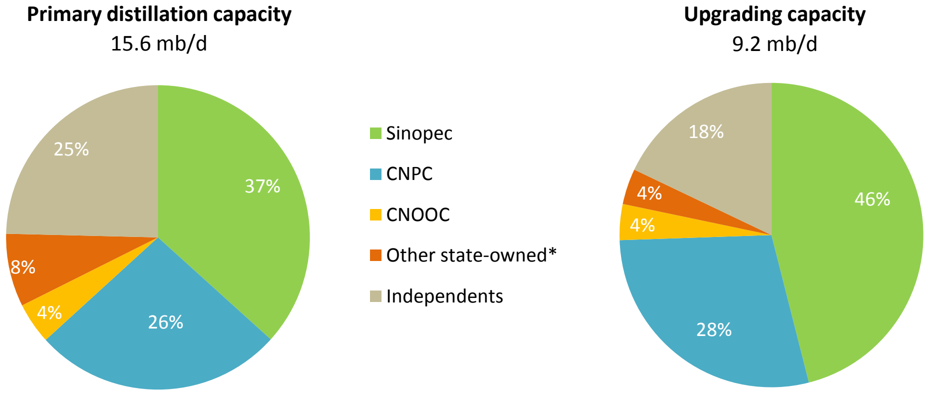
14.3.1 Market structure and reform

China's oil production is heavily concentrated in the hands of three major national oil companies (NOCs): China National Petroleum Corporation (CNPC); China Petroleum and Chemical Corporation (Sinopec); and China National Offshore Oil Corporation (CNOOC). Together, they account for more than 90% of oil production in China. Participation by private Chinese companies in the oil sector has been limited to the provision of oilfield services: small private service companies proliferated in the decade of higher oil prices to 2014, but the subsequent sharp fall in the oil price – and various corruption investigations – led to a shakeout in the sector. Participation of international oil companies in the Chinese upstream sector has been allowed mainly through production sharing contracts for offshore prospects or technically challenging plays.

Attracting more private participation, capital and advanced technology to China's upstream sector has grown in importance as a policy objective. A reform plan approved in May 2017 promised changes to improve corporate governance in the NOCs via "mixed ownership", which would allow private companies to hold ownership stakes in the NOCs, as well as changes to allow participation by private companies in exploration and development activities for oil and gas. Investment in China's complex resource base has been stymied by low international prices: many prospective oil projects, including enhanced oil recovery projects, struggle to break even at $40-50 per barrel (bbl). With revenue and domestic investment opportunities squeezed, the big three NOCs cut their domestic capital spending by 40-60% over the past two years. A broader investor base and the entry of new players, including specialised technology players, could be a vital factor in stemming the current decline in output.

The situation in the refining sector is somewhat different. The Chinese refining industry is split between refineries operated by the major NOCs and those run by independent companies (sometimes known by the pejorative name of "teapots", although many are technically and commercially very sophisticated). At the end of 2016, the three large NOCs – Sinopec, CNPC and CNOOC – and other state-owned enterprises – ChemChina, Sinochem, Norinco and Yanchang Group – together accounted for three-quarters of total refining capacity, with independents making up the remainder. Sinopec has the leading position with 5.7 million barrels per day (mb/d) of capacity, followed by CNPC with 4.1 mb/d (Figure 14.8). Prices for most products and consumers have made strides towards liberalisation in recent years, as part of a broader programme of subsidy reform, although they are still subject to certain price caps or floors set by the NDRC (Box 14.2).

Figure 14.8 ▹ Breakdown of refining capacity in China, end-2016



Independent refineries account for around a quarter of primary distillation capacity

* Sinochem, ChemChina, Norinco and Yanchang Group. Note: Upgrading capacity is expressed as the sum of various types of conversion capacity converted to fluid catalytic cracking (FCC) equivalent capacity.

There are significant differences between NOC-owned refineries and independent refineries in terms of size, configuration and location. The average size of refineries owned by Sinopec and CNPC is 150 thousand barrels per day (kb/d) while the size of independent refineries is around 20-100 kb/d. With their deep conversion capability, NOC-owned refineries are generally configured to process heavier and high-sulfur crude and to yield high-value products. With much lower upgrading capability (and no access to reliable crude supply prior to 2015), independent refineries generally took straight run fuel oil or bitumen and produce middle distillates with a high residue proportion. While NOC-owned refineries are located across the country, the independents are mostly concentrated in Shandong province, although they are well represented in others provinces too, including Liaoning, Hebei, Ningxia and Jiangsu.

Before 2015, independent refineries operated under a tight regulatory regime, with no right to import crude or export products, and their utilisation levels were around 30-40%. However, the situation has changed since 2015, with crude import quotas being granted to an increasing number of refiners (21 companies as of mid-2017) on condition that they shut smaller units (under 40 kb/d).[3] This partial liberalisation represents an attempt by the NDRC to introduce competition into an NOC-dominated sector (crude imports by independents surged to more than 1 mb/d in 2017), while improving productivity and reducing excess capacity at the same time.

Box 14.1 ▷ Road to subsidy reform in China

China published for the first time an inventory of inefficient fossil-fuel subsidies in November 2015, following a joint review by China and the United States (conducted in a G20 framework).[4] It identified nine specific subsidies and proposed timeframes for their removal or reform, in line with the desire of the China's government to let markets play a "decisive" role in the economic system.

With a cumulative subsidy of almost $90 billion (yuan renminbi [CNY] 575 billion) over the ten years to 2015, the main programme by far was a system of direct transfers for groups considered vulnerable to the impact of price liberalisation for oil products. Oil price liberalisation began in earnest in the 2000s and domestic prices for most oil products have largely shadowed international prices since 2009, albeit with certain ceiling and floor prices in place. However, low-income consumers and those requiring oil products for professional use (e.g. in public transport, taxi fleets, farming, forestry and fisheries) were eligible for a partial rebate on their fuel consumption.

While it fulfilled the aim to protect potentially vulnerable groups, the programme did little to encourage efficient consumption and was also open to abuse. The reform effort has now capped the available subsidy at the level it reached in 2014 ahead of gradual reductions according to a set timetable, which will bring it down by 15% in 2015 and by 60% in 2019. Alongside such reforms on the consumption side, subsidies for fossil-fuel production are also being reduced, with the progressive removal of support to shale gas extraction a good example (see section 14.4).

Some subsidies for low-carbon energy and related technologies are also being reviewed and reformed. A trading system for green certificates started in July 2017 with the intention of easing direct payments for renewables-based generation, and a scheme that provides subsidies for electric vehicles will have its budget reduced by 20% every two years from the 2016 level through to 2020. These changes are accompanied by the planned introduction of carbon pricing and by reforms to the taxation system, all of which are intended to put a price on environmental externalities while opening up a larger role for the market to allocate resources and investment in a more efficient way.

3. Export quotas were also granted albeit at a lower quantity, but the government did not issue 2017 export quotas for independent refineries.

4. A full inventory is available in the China self-review report of the G20 peer review, *www.oecd.org/site/tadffss/publication/G20%20China%20Self%20Review%20on%20Fossil%20Fuel%20Subsidies-China%20Self-report-20160902_English.pdf*.

However, while the best of the independents are operated in an increasingly professional and dynamic way, the sector as a whole faces a number of challenges. Independents have cost disadvantages, relying largely on trucks to transport crude or oil products, whereas the NOCs have extensive pipeline networks and storage tanks. They also tend to produce lots of diesel (it is their main refined output) which they are not allowed to export. At the same time, stricter environmental standards on low sulfur content are taking a toll on the bottom line, and many face increasing scrutiny of business practices and tax arrangements.

In our projections, we expect a parting of the ways for the independent refiners. The best are set to survive, and indeed several companies are making considerable efforts to stay competitive through large-scale investment, integration with petrochemicals, joint crude procurement or acquisitions to increase scale (the provincial government of Shandong recently approved a plan to merge major refineries in the province into a large conglomerate). These stronger independents – for which the term "teapots" is increasingly unsuitable – will be an important dynamic force in the sector, introducing diversity and competition in the market. Conversely, smaller, less efficient refineries are likely to close, and the net effect is a slight increase in the market share of the main NOC-owned refineries.

14.3.2 Outlook for oil

Summary of demand trends

In the New Policies Scenario, China's oil demand increases by 35% from 11.5 mb/d in 2016 to 15.5 mb/d in 2040. The majority of the growth occurs through to 2030 thanks to robust economic growth, rapid urbanisation and a growing number of passenger vehicles on the road. The pace of growth slows considerably after 2030 as gasoline-fueled vehicle ownership goes into decline and electric cars increase their market share. Gasoline demand rises rapidly until 2030, before flattening and entering a period of decline, while diesel demand slows in the near term and resumes its growth after 2030, boosted by economic growth in the western provinces. Naphtha registers the largest demand increase as a result of robust growth in petrochemicals production. Despite a vast amount of untapped resources, oil production in China continues to fall because of maturing production from existing fields and insufficient new projects to offset these declines, leading to a substantial increase in dependence on imported oil (Table 14.3). China remains the world's largest oil importer throughout the period to 2040.

Resources and reserves

China has significant remaining technically recoverable oil resources, estimated at 114 billion barrels at the end of 2016. Conventional onshore represents around 40% of this figure, with tight oil, offshore and natural gas liquids (NGLs) making up the remainder. As in the case of shale gas, China has major tight oil potential: its estimated technically recoverable resources amount to 32 billion barrels, larger than any country other than the United States and Russia. Oil production to date has mostly been concentrated on conventional onshore plays: other types of resources such as tight oil or deepwater prospects remain largely untapped, as do onshore resources in the western interior provinces such as the Tarim, Junggar and Qaidam basins. The key challenge for China lies not in the volume of resources, but in their complexity and the relatively high cost of their development. Conventional onshore oil accounts for almost 90% of the proven reserves, compared with less than half of remaining recoverable resources, indicating that relatively little headway has been made in turning the potential of unconventional sources into a viable commercial proposition (Table 14.4).

Table 14.3 ▷ China oil demand, production and net trade (mb/d)

	2000	2016	2025	2030	2035	2040	2016-40 Change	2016-40 CAAGR*
Demand	4.7	11.5	14.5	15.4	15.5	15.5	4.1	1.3%
LPG	0.4	1.4	1.6	1.6	1.6	1.6	0.2	0.5%
Naphtha	0.5	1.1	1.7	2.0	2.3	2.5	1.4	3.4%
Motor gasoline	0.8	2.8	4.2	4.4	4.0	3.7	0.8	1.1%
Kerosene	0.2	0.4	0.6	0.7	0.8	0.9	0.4	3.0%
Diesel	1.5	3.4	3.6	3.8	4.0	4.2	0.8	0.8%
Fuel oil	0.7	0.2	0.3	0.4	0.4	0.4	0.2	2.1%
Production	3.3	4.0	3.5	3.3	3.2	3.1	-0.9	-1.1%
Conventional	3.3	4.0	3.3	2.9	2.6	2.5	-1.5	-1.9%
Unconventional	0.0	0.1	0.3	0.4	0.6	0.6	0.6	10.6%
Net imports**	1.6	7.9	11.5	12.5	12.8	13.0	5.1	2.1%
Crude imports	1.9	7.6	9.2	10.4	10.8	11.3	3.7	1.7%

* Compound average annual growth rate. ** Takes into account demand for bunker fuels (international marine and aviation) and processing gains during oil refining. Note: LPG = liquefied petroleum gas.

Table 14.4 ▷ Remaining technically recoverable oil resources by type in China, end-2016 (billion barrels)

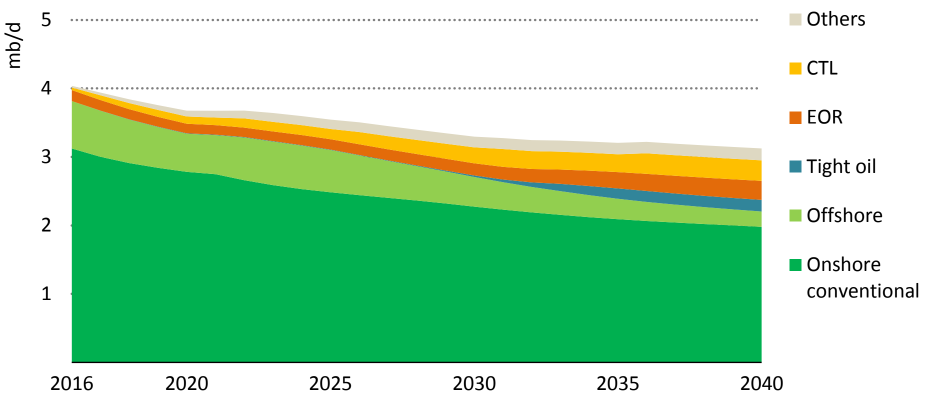
	Technically recoverable resources	Cumulative production	Remaining recoverable resources	Remaining % of TRR	Proven reserves
Conventional onshore	94.2	48.7	45.5	48%	23.6
Shallow offshore	11.1	4.0	7.1	64%	3.0
Deep offshore	0.3	0.1	0.3	85%	0.0
Tight oil	32.2	0.0	32.2	100%	0.0
NGLs	21.9	0.0	21.9	100%	0.1
Total China*	**166.7**	**52.8**	**113.9**	**68%**	**27.2**

* Includes extra-heavy oil and bitumen and kerogen oil. Notes: Data include crude, condensate and NGLs. Most NGLs are assumed to be associated with China's large shale gas resources, which is why produced volumes thus far are negligible. TRR = technically recoverable resources.

Production prospects

China is the seventh-largest oil producer in the world, accounting for 4.5% of global oil production in 2016. China's domestic oil production grew continuously from 2000 until 2015, but maturing production from existing fields and investment cuts by the major NOCs after the fall in oil prices led to a 7% production decline between 2015 and 2016. Most of the current major oilfields have produced oil for more than 30 years and are now facing sharply declining production. It is however difficult to secure investment for new projects to compensate for these declines because of the low oil price, and the focus of the NOCs is in any case shifting towards gas. In our projections, China's oil production continues to fall from 4.0 mb/d today to 3.1 mb/d by 2040 (Figure 14.9).

Figure 14.9 ▷ China's oil production in the New Policies Scenario



Declines from mature fields and lack of new projects lead to a continued fall in production

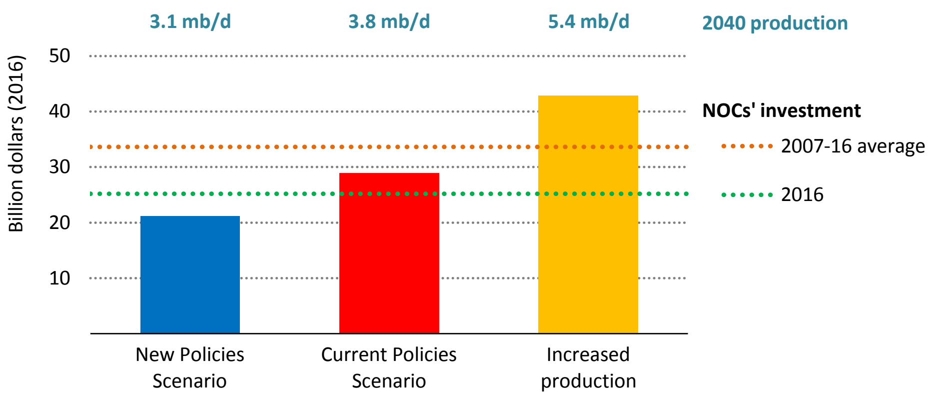
Note: CTL = coal-to-liquids; EOR = enhanced oil recovery.

Tight oil has generated a lot of interest in recent years with discoveries of sizeable reserves, for example, CNPC's 700 million barrels discovery in the Ordos Basin. However, it shares the similar challenges that weigh on shale gas development: these include complex geology, water stress in arid areas, and logistical constraints (see next section). With lower prices in the first-half of the projection period also mitigating against a big push in this area, our projected tight oil output comes mostly after 2030, reaching 5% of total oil supply by 2040.

A wider use of enhanced oil recovery (EOR) offers another avenue to boost production in mature fields. The volume of technically recoverable resources through EOR amounts to an estimated 11 billion barrels, with the majority coming from chemical and thermal methods of recovery but the potential of carbon-dioxide (CO_2) recovery is also growing. Despite its relatively high cost, there are two main reasons for believing that EOR in China has greater potential than in other countries. The first is that the large size of existing fields (such as those in the Daqing or Shengli complexes) means that a small improvement in recovery factors can translate into a substantial overall boost to production. The second is that China has accumulated considerable experience in EOR projects in recent years, and the geological uncertainties associated with EOR are relatively well understood in key plays. China has particular experience in respect of the chemical EOR pathway, but has also gained practical experience of CO_2-EOR and is envisaging further projects. The key challenge is to match the knowledge gained from research on reservoirs and technologies with improvements in well drilling and facilities performance, which account for a large part of total capital cost.

Coal-to-liquids (CTL) plants, which convert coal into oil or chemical products, gained prominence when oil prices were high. The drop in oil prices since 2014, together with other factors such as the large volumes of water used by CTL plants and their high emissions, has weighed on the prospects for future investment. The 13th Five-Year Plan, however, included a renewed push for CTL projects with an ambitious target of boosting CTL production to 13 million tonnes per year (roughly 270 kb/d) by 2020.[5] The government has also exempted CTL projects from the consumption tax, which accounts for roughly 30% of the total operating cost at CTL plants (IEA, 2017a). As a result, CTL production is projected to increase from 40 kb/d today to 300 kb/d by 2040 (10% of total oil production), offsetting in part the declines from conventional wells.

Figure 14.10 ▷ Required annual investment for China's oil supply by production level



Reversing the decline in China's oil production requires not only higher prices, but a significant boost in capital expenditure, compared with historical levels

Overall, the new conventional fields that are brought into operation and the growth in production from unconventional plays are not sufficient in our main scenario to arrest the trend of declining production. What would it take to turn the tide? Higher oil prices

5. The target does not include coal-to-olefins or coal-to-methanol projects.

would certainly make a difference: in the Current Policies Scenario, which has higher prices than in the New Policies Scenario, the decline in oil production slows and total output stays at around 3.8 mb/d by 2040. However, reviving production growth would require a significant additional effort even with higher prices. An illustrative case, in which China's oil output returns to its 2016 level by the late 2020s and then rises to 5.4 mb/d by 2040 (over 30% higher than today), requires not only higher prices (at the level of the Current Policies Scenario) but also more favourable assumed conditions for upstream operators. The investment required in this illustrative case rises to around $43 billion per year, almost double the levels seen in the New Policies Scenario and well beyond the historical investment levels of the three major NOCs (Figure 14.10). This is because a much larger share of production would need to come from technically challenging plays, notably tight oil and offshore. This analysis underlines the crucial role that the envisaged upstream reforms could play in attracting new players to China's oil sector, mobilising additional capital and expertise to develop frontier plays.

14.3.3 Oil trade and refining

Crude oil

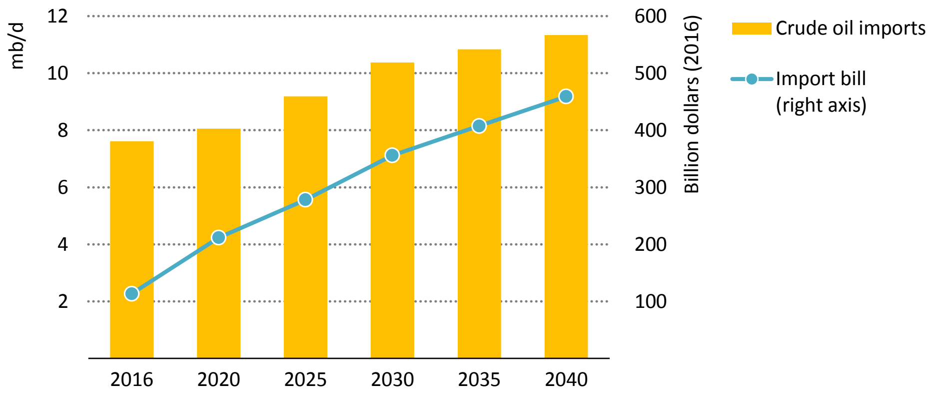
In 2000, China imported around 1.4 mb/d of crude oil, less than 15% of the amount the United States imported that year. However, strong demand for oil products and a huge growth in refining capacity over the past 15 years raised China's imports of crude oil to 7.6 mb/d in 2016, putting it on par with the United States.[6] Although both countries are importing a similar amount of crude oil today, they are projected to move in completely different directions in the future. The United States reduces its crude import requirements thanks to rising domestic output and falling demand (from an average of 20 barrels of oil consumed per capita each year today). By contrast, China's domestic production is in decline and it will be a major policy struggle to limit the increase in demand (from the current average of 3 barrels per capita per year). Our projections suggest that China's crude oil imports continue to increase and reach 11.3 mb/d by 2040, almost double the amount that the United States imports in that year, and that the country's dependency on imported crude oil rises from 70% to more than 80% over the same period. China's import bill is set to grow even faster, from around $110 billion today to $460 billion by 2040, owing to the combined effect of volume and oil price increases (Figure 14.11).

Since China turned into a net importer of oil in the early 1990s, the rise in imported volumes has become a major concern of China's policy-makers. China's oil imports come from a small number of sources in the Middle East and Africa, using a limited number of routes: in 2010, the Middle East and Africa accounted for three-quarters of China's total crude oil import, and around 80% of imports are estimated to have come through the Strait of Malacca (Box 14.2). This situation improved somewhat from 2010 to 2016 and, in the

6. In the first-half of 2017, China imported a record high 8.6 mb/d of crude oil due in part to a buying spree by independent refiners to use up the import quota.

New Policies Scenario, the import picture again becomes slightly more diverse because of growth in oil imports from Eurasia and North America, notably from Canada. With the projected need for an additional 4 mb/d of crude oil imports, however, reliance on the Middle East remains high, and the volumes transiting through Southeast Asia likewise remain high. The energy security implications of this picture – and the strategic choices that they imply for China – are discussed in more detail in Chapter 15.

Figure 14.11 ▷ China's crude oil import volume and associated import bill in the New Policies Scenario



China's crude import needs rise to 11 mb/d by 2040 and the import bill grows even faster

Box 14.2 ▷ The quest for oil security so far

Alongside policy changes on the domestic market, China has made a concerted effort to address oil security concerns in recent years. One approach has been to invest in overseas oil producing assets, either directly or through the form of "loans for oil". During the past two decades, China has made a cumulative investment of around $270 billion in overseas assets, of which $90 billion has been extended as loans to be repaid with oil. While these investments raised China's equity in overseas oil output to around 3 mb/d in 2016, their actual contribution to oil security is much debated. The government is now taking a more selective approach and reorienting investments towards the countries aligned with the Belt and Road Initiative, including Russia, Iran and Iraq (IEA, 2017b).

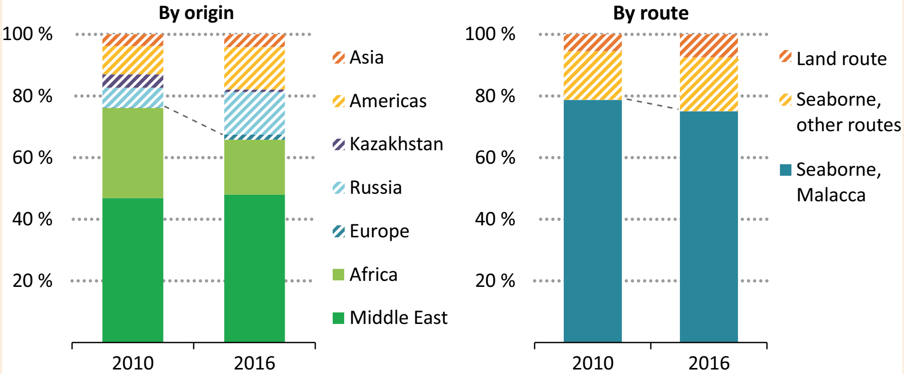
A second approach has been to pursue a significant build-up of domestic oil stocks under the "Mid-Long-Term Plan of National Oil Stocks". The build-up gathered pace amid low oil prices: according to China's National Bureau of Statistics, oil stocks in the middle of 2016 stood at around 245 million barrels (more than 30 days of net imports). The government aims to increase oil stocks further by 2020 to enhance the ability to respond to potential supply disruptions.

A third approach has been a quest to develop land-based trade routes for oil delivery, which would reduce reliance on seaborne shipments and chokepoints. Given their relative proximity and abundant resources, it is no surprise that Russia and Kazakhstan have been central to this effort. The Kazakhstan-China pipeline began operation in 2006 and can now bring 400 kb/d of oil to the Chinese border. The oil relationship with Russia has also progressed rapidly (more so than in the gas sector): the East Siberian-Pacific Ocean (ESPO) pipeline, commissioned in phases between 2009 and 2012, brings east Siberian oil to Asia Pacific markets via Kozmino Bay or to China through a spur line to Daqing. In 2016, the pipeline delivered 1 mb/d of crude oil, of which roughly 80% were imported to China. With other routes, the share of imports from Russia more than doubled from 6% in 2010 to 14% in 2016 and as a result surpassed that of Saudi Arabia.

A fourth approach has focussed on efforts to reduce the "call on Malacca". The long-delayed Myanmar-China pipeline completed its first delivery in 2017 from the Bay of Bengal to Kunming in Yunnan province. With a capacity of 440 kb/d, it takes crude oil from the Middle East or Africa and delivers it to China without it having to pass through the Straits of Malacca, easing risks from physical disruptions and allowing faster delivery.

Because of these measures to diversify supply sources and routes, the combined share of imports from the Middle East and Africa to China has declined since 2010 from three-quarters to less than two-thirds. The share of oil flowing via Malacca has also decreased from around 80% to 75% (Figure 14.12).

Figure 14.12 ▷ China's crude oil imports by origin and route



Diversification efforts have reduced China's reliance on imports from the Middle East and Africa via the Strait of Malacca, but challenges remain

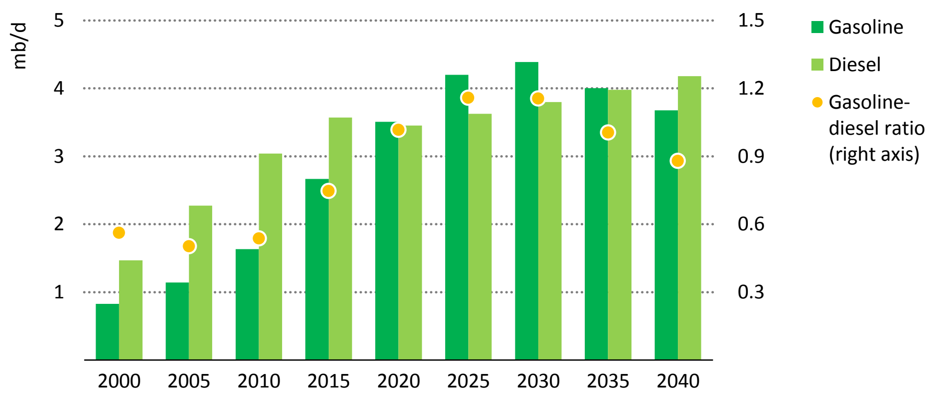
14

Strategic challenges for refiners

Our projections to 2040 highlight two major challenges facing China's refining sector once the immediate restructuring process is complete: first, the changing composition of China's product demand; and second, tightening environmental quality standards for oil products.

On the first issue, demand for diesel has grown by more than 5% per year on average for the past 15 years, largely because of consumption by the heavy machinery and trucks that have supported China's massive infrastructure build-up and industrial growth. However, a shift towards consumer-driven economic growth is changing this picture. In the New Policies Scenario, growth in diesel demand slows dramatically over the next few years. Instead, gasoline takes over the driver's seat for oil demand growth as the number of passenger cars on the road swells three-fold from 164 million today to 470 million by 2030. Gasoline demand is projected to overtake demand for diesel by around 2020, reaching 4.4 mb/d in 2030. However, the balance between gasoline and diesel changes again between 2030 and 2040 as gasoline consumption in passenger cars peaks in the face of competition from electric cars, while diesel demand increases again as economic growth in the western provinces spurs higher inland road freight activity. Between 2030 and 2040, diesel demand rises by nearly 400 kb/d while gasoline demand declines by over 700 kb/d (Figure 14.13).

Figure 14.13 ▷ Gasoline and diesel demand in China in the New Policies Scenario



Gasoline takes the driver's seat in China's oil demand growth to 2030, but then diesel reclaims its position with higher road freight activities

For Chinese refineries that have traditionally been configured to serve increasing diesel demand, surging demand for gasoline (and stagnant diesel demand) until 2030 represents a marked shift. The process of change has already started, thanks in part to new capacity coming online and to the sourcing of lighter crudes: compared with 2012, refinery yields have already started to switch towards gasoline (up from a 25% share in 2012 to 26% in 2016) and away from diesel (down from 37% in 2012 to 32% in 2016). Those that can successfully adapt to the new environment stand to benefit, but not all refineries have room or capability to make necessary investments: the shift in demand could will exacerbate the financial problems facing smaller refiners, who continue to sell middle distillates into a market where both domestic sales and export outlets are constrained. In the longer term, another shift in the demand barrel towards diesel (and away from gasoline) poses further challenges for Chinese refiners: refiners will need to compete with other gasoline exporters, such as the United States, in Asian markets.

On the second major challenge, there is growing pressure on refiners as a result of China's tightening of environmental standards for transportation fuels in order to curb air pollution.[7] In 2017, the government implemented the National V standard, which requires lowering the sulfur content in gasoline and diesel to no more than 10 ppm (equivalent to the Euro V standard), with a plan to introduce the strengthened National VI standard by 2020. Implementation of the National V standard for non-automotive diesel is also being considered. Tougher standards bring welcome environmental improvements, but they require refiners to put a significant amount of capital into upgrades and/or retrofits. Chinese refiners, both state-owned and independents, have invested heavily in hydrotreating and desulfurisation capacity over the past decade, raising the share of desulfurisation capacity relative to distillation capacity from 15% in 2006 to around 35% in 2016. However, the share is still lower than the global average of 51%, and mobilising capital for investment during a period of overcapacity will be challenging, especially for independent refiners.

Refinery runs, product balances and trade

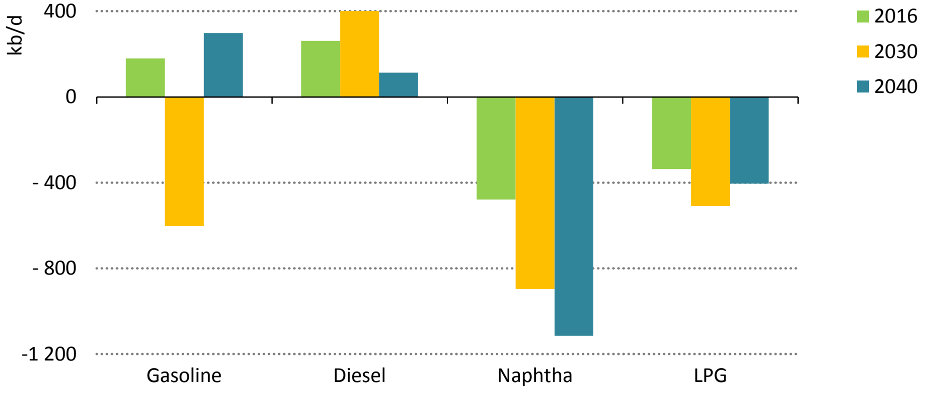
By 2040, China becomes the leading refining centre in the world, with refinery runs overtaking those in the United States and reaching 14 mb/d by 2040, 30% up from today. Even with this increase, China remains a net product importer over the *Outlook* period, with around 1.5 mb/d of net imports in 2040. Relatively fast demand growth increases the country's net product import requirement for the first-half of the projection period. In the latter part of the period, product import needs gradually fall back as demand growth slows.

However, the aggregate net product balance masks varying trade patterns by product. In our projections, a prolonged mismatch between the composition of demand and what refineries produce makes China a net importer of certain products and an exporter of other products. Thanks to robust demand for petrochemical feedstock, imports of liquefied petroleum gas (LPG) and naphtha increase over the period to 2040. Gasoline imports also grow in the medium term, although not in the long term. On the other hand, the combined effect of weakening demand and rising refinery runs makes China a net exporter of middle distillates such as diesel through to 2030, although the surplus shrinks in the long term

7. See Chapter 4 for the implications of the decision by the International Maritime Organisation to introduce a 0.5% cap on the sulfur content in marine fuels from 2020 onwards.

(Figure 14.14). We project the net addition of some 2.6 mb/d of new refining capacity over the next 25 years, with total capacity reaching 18.2 mb/d by 2040. If additional capacity comes online beyond these expectations, there is a chance of China emerging as a major product exporter in the latter part of the projection period, which would push the country's crude oil import requirement even higher.

Figure 14.14 ▷ Trade balance of key refined products in China in the New Policies Scenario



The trade balance for gasoline and diesel changes markedly, but there is no change in China's need for imports of naphtha and LPG

14.4 Natural gas

14.4.1 Market structure and reform

The Chinese natural gas market remains heavily regulated along the entire supply chain. As with the oil sector, the upstream and midstream is very concentrated, and the three NOCs (CNPC, Sinopec and CNOOC) dominate the production and transmission of gas. With hundreds of different companies distributing gas to consumers, the distribution sector appears more diverse: in reality, the distribution companies have local monopolies and hardly compete with each other for customers. This structure has allowed the gas market in China to grow very quickly over the last decade, but it is widely seen as inadequate for the next stage in its development. Shifting to a more market-oriented and open gas market is now an energy policy priority in China. Experience in OECD countries shows that liberalisation of gas markets can be a long and drawn-out process. In the Chinese context, where gas supply is relatively expensive, coal is amply available, and the cost of key renewable technologies continues to fall, it cannot be taken for granted that a well-functioning market on its own will be sufficient to secure the future of gas. If gas is to thrive, some combination of market incentives and policy interventions that reflect a strategic choice in favour of gas is needed.

Establishing diversity and competition in the upstream

The regulatory regime for conventional upstream gas is similar to that for oil: state-owned companies dominate, with most conventional gas exploration licences onshore held by CNPC and Sinopec, and most offshore conventional gas exploration licences held by CNOOC. Opportunities for private companies, including foreign companies, are circumscribed; private participation in the conventional sector (and in tight gas development, which is considered as conventional in China) has thus far been either as a service provider or as a partner with one of the major NOCs.

The position on shale is different. Shale gas was designated a separate mineral resource in 2011 and has its own regulatory regime, under which private companies have the right to develop shale resources. Two shale gas bidding rounds have introduced new owners into the mix, although CNPC and Sinopec retain the bulk of the most promising shale acreage and, in practice, non-NOC participation is still in its infancy.

Since 2012, shale gas production has been subsidised at a rate of CNY 0.4/cubic metre (m^3), equivalent to \$1.6 per million British thermal units (MBtu). However, the subsidy did not prove effective in triggering a take-off in shale gas production and the authorities have decided to phase it out gradually. The subsidy will be cut by half to CNY 0.2/m^3 (\$0.8/MBtu) by 2020 and there is no commitment to provide support beyond then. This move reflects the inherent tensions between a government understandably keen to reduce energy subsidies, while promoting the strategic development of a major national resource base that could bring significant energy security, regional development and employment benefits.

The regulatory framework for coalbed methane (CBM) is close to that of conventional gas, in that the central Ministry of Land and Resources allocates the development rights to state-owned companies. Nonetheless, it is made more complicated by the overlap with coal exploitation rights that are granted at provincial level.[8] In contrast to shale, the existing subsidy for coalbed methane is being raised to CNY 0.3/m^3 (\$1.2/MBtu) from CNY 0.2/m^3 (\$0.8/MBtu), reflecting the social importance of additional economic activity in regions where coal mining may be restructured, and the desire to tap coal resources in a more environmentally acceptable fashion.

Although the possibilities to participate in China's upstream sector are gradually growing, opportunities for new private players, including international oil and gas companies, remain restricted. In the case of shale gas, most foreign oil and gas companies that had entered joint study agreements with domestic partners on shale gas development have gradually pulled out: among the reasons cited were uncertainties over the quality of the resource, a challenging cost situation and unfavourable fiscal terms. Moreover, access to transmission infrastructure remains a major constraint for new players, deterring them from taking up larger stakes in the upstream (see section below). Upstream reform is expected to take

8. The Shanxi provincial government, where most CBM is produced, is testing a new approval process whereby all approvals are done at provincial level.

time, with the bulk of gas production remaining firmly in the hands of the major NOCs (CNPC accounts for about 70% of China's gas production, Sinopec about 15%, and CNOOC about 10%). Creating a competitive upstream environment is however a precondition for stimulating the innovation (both technological and commercial) needed to bring down costs and tap unconventional gas deposits that are geologically challenging.

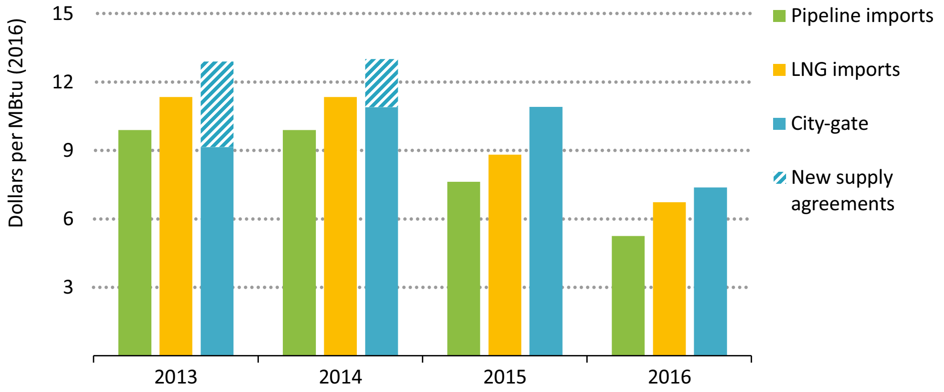
Finding a price that kills two birds with one stone

China's government is pursuing the goal of fully liberalising producer and consumer prices while regulating network tariffs. An important step towards this goal was the introduction of a uniform city-gate price – generally speaking a wholesale price – in 2015. Prior to this, there were two city-gate prices in place: one for "stock gas" and one for "incremental gas", i.e. the price mechanism discriminated between existing and new supply agreements. The latest pricing reform, passed in late 2016, has introduced important elements of market-based price formation and tighter regulation of pipeline tariffs, but there is still a long way to go before the system is fully liberalised.

At present, around half of the gas consumed in China is marketed without any price regulation. This includes all liquefied natural gas (LNG), unconventional gas (shale gas, coalbed methane and synthetic gas), gas sold to the fertiliser industry, and gas bought by end-users directly from NOCs, mostly by large industrial facilities. Prices paid by residential gas consumers, accounting for a little less than a fifth of China's gas use, remain fully regulated by the NDRC at preferential rates. Prices for non-residential gas consumers that are not large enough to directly buy gas and which rely on conventional output or imported pipeline gas are partially regulated: this consumer group accounts for some 30% of China's gas consumption. Partial regulation means that the NDRC sets a benchmark city-gate price but allows buyers and sellers to negotiate prices that are lower either than the benchmark or up to 20% higher. City-gate benchmark prices include the pipeline tariffs and are thus typically higher than the import prices for LNG or pipeline gas (Figure 14.15).

China has a choice to make about whether to focus on a market-oriented pricing approach based on indexation to alternative fuels or whether to introduce a larger degree of gas-to-gas competition by establishing a gas trading hub (or hubs: there are promising signs both in Shanghai and in Chongqing). Both domestic gas consumers and producers have important interests that bear on this. On the one hand, low gas prices stimulate growth in gas demand and help to push out more polluting fuels such as coal and oil, improving air quality and reducing CO_2 emissions. On the other hand, domestic gas prices at the level of the LNG import price would currently be insufficient to stimulate much upstream activity, especially for unconventional gas. China has a strong strategic rationale (encompassing domestic welfare creation, development of a major indigenous energy resource, energy security and long-term competitiveness) to continue development of domestic unconventional gas, with the aim of gaining experience and gradually bringing down production costs.

Figure 14.15 ▷ Average natural gas import prices and average city-gate benchmark price in China



Recent price reforms have brought city-gate prices down and aligned them more closely with import prices for LNG and pipeline gas

Note: Hatched areas indicate the city-gate price for "incremental gas", i.e. new supply agreements.

Creating a level playing field for access to infrastructure

The NDRC regulates the midstream infrastructure and grants approvals for the construction of long-distance pipelines and regasification facilities. The pipeline network is currently an important constraint on growth. Although infrastructure has been built up rapidly in recent years and the total length of long-distance pipelines had reached nearly 68 000 km in 2015, it remains undersized for a country that has ambitions to increase the share of gas in the energy mix. (As a comparison, the United States, a country of similar land mass, has almost 500 000 km of long-distance gas transmission infrastructure). PetroChina, a subsidiary of CNPC, the dominant player in the country's midstream sector, owns almost three-quarters of the country's long-distance pipelines. The local distribution network has a length of 430 000 km and is operated by hundreds of different companies that typically have a local monopoly. Despite the apparent diversity, concentration in the distribution business is high, with two-thirds of the gas sales carried out by only six companies.

In 2014, the NDRC (via the National Energy Administration) made some initial steps towards implementing third-party access to the transmission network. The new policy requires pipeline operators to grant other players access to their network, but this third-party access is currently limited to spare pipeline capacity only. Since the pipeline infrastructure has a large number of bottlenecks, the impact of this new regulation has been limited to date. As for LNG, to date only a few import facilities are open for third-party access: although there is ample spare capacity, the incumbents have been reluctant to accommodate new market entrants.

Direction of reform in the New Policies Scenario

Gas market reform is not a stand-alone policy item: it forms one part of a wider set of linked energy market reform in China. Electricity and coal markets – both of critical importance to the gas market – are currently also undergoing reform and restructuring, a process that is expected to stretch well into the second-half of the 2020s. Given the likely length of the reform journey and the linkages with other sectors, clarity over the process, the legal framework and the future role of gas in the energy system will be important in providing certainty for market participants.

Price reform is an essential component of a functioning gas market but its success is contingent on effective implementation of upstream and midstream reform. Market-based pricing can only lead to greater economic efficiency if the market is competitively organised and if there is a high degree of trust from participants in its operation. This implies market reform going hand-in-hand with the establishment of a regulatory authority given clear responsibilities and powers by government, and authorised to act independently in accordance with those responsibilities and powers. It requires a clear definition of the responsibilities of the different government entities involved, underpinned by the principle of transparency and by the availability of data. The trends in our New Policies Scenario thus rest on three basic assumptions for gas market reform, reflecting our understanding of today's policy intentions:

- Transparent and equal third-party access to infrastructure is extended beyond spare capacity within the next few years, and includes ownership unbundling of upstream, midstream and downstream activities. Sufficient incentives for new investment are created to alleviate capacity constraints in the network and to build storage capacity. Incentives that would make a difference include ex-ante cost approval, a reasonable rate of return and properly defined depreciation periods.
- Access to China's resource base is liberalised, including by opening conventional oil and gas resources to eligible companies through bidding rounds and by improving the conditions for private participation in unconventional gas production. The hoarding of licences is penalised (so that companies that do not live up to their resource development plans lose their licences) and the main state-owned companies are required to relinquish some of their existing blocks.
- Market-based pricing mechanisms are gradually introduced, and include the introduction of a spot market and the achievement of full price liberalisation in the second-half of the 2020s, with de-regulation of residential gas prices as the final step.

The projected increase in gas prices in the long term will serve to strengthen the competitiveness of domestic production, but also to weaken the competitiveness of gas against other fuels in some end-use sectors, slowing gas demand growth and risking the derailing of other energy policy goals. We therefore believe that, while a comprehensive gas market reform is a necessary condition for gas to play a more significant role in China's future energy mix, it is not enough on its own. Policies that support an expansion of gas use in end-use sectors – especially from the mid-2020s onwards – play a critical role for the demand and supply trends in the New Policies Scenario. As described in Chapter 13, among the most important are continued efforts to improve air quality through coal-to-gas switching in the heat and industry sectors, efforts to reduce reliance on oil in the transport sector and the introduction of an emissions trading system.

The New Policies Scenario remains subject to uncertainties about the depth and the speed at which reforms are implemented, and the effectiveness of policies designed to underpin greater gas use. On the one hand, various difficulties could stall or delay gas market reform, holding back the prospects for shale gas development, calling into question the longer term role of gas in the Chinese energy system and increasing the likelihood of a coal-plus-renewables pathway for the energy mix. On the other hand, China has an admirable record of addressing its energy challenges in a way that unlocks rapid growth: if that happens, higher domestic output could help gas to penetrate more rapidly into China's energy mix, reducing emissions and helping to improve air quality where it replaces more polluting fuels. In either case, there would be significant implications for China's need for imported gas.

Summary of natural gas demand trends

In the New Policies Scenario, China's gas demand rises by nearly 5% per year, taking demand in 2040 to over 600 billion cubic metres (bcm) and making it the second-largest market globally behind the United States. The absolute increase of 400 bcm to 2040 represents around a quarter of global demand growth, and results in a doubling of the share of gas in China's energy mix from under 6% to over 12%. Growth is particularly strong in the light industrial subsectors (such as textiles, food and beverages, and footwear) where the convenience and environmental advantages of gas see demand increase five-fold to 125 bcm, making this one of the key areas of expanding gas use worldwide. Demand in other industry subsectors (such as iron and steel, chemicals, non-ferrous metals) triples, taking consumption in the industry sector as a whole to nearly 200 bcm, from 50 bcm today.

Demand in the power sector grows from 50 bcm to 170 bcm, making it another of the largest growth areas for gas in the *Outlook*. Even though gas-fired generation rises from 200 terawatt-hours (TWh) to over 800 TWh, gas-fired power still contributes only 8% to the power mix, and its growth rate is well below that projected for renewables. Consumption of gas in the buildings sector grows more modestly, from 50 bcm to 125 bcm, in line with the expansion of the distribution network. Transport natural gas consumption triples to 60 bcm, based on increasing use in the road passenger and freight segments.

Table 14.5 ▷ China natural gas demand, production and trade in the New Policies Scenario (bcm)

	2000	2016	2025	2030	2035	2040	2016-2040	
							Change	CAAGR*
Demand	28	210	397	482	554	610	401	4.6%
Power generation	6	50	112	135	155	171	121	5.3%
Industry**	11	61	127	161	190	214	152	5.3%
Buildings	5	51	85	102	117	126	74	3.8%
Transport	0	21	41	50	56	62	42	4.7%
Other***	7	26	31	34	36	37	11	1.5%
Production	27	137	222	261	298	336	199	3.8%
Conventional	27	98	125	127	122	110	12	0.5%
Unconventional	0	38	96	133	176	226	188	7.7%
Net imports****	1	73	177	224	259	278	206	5.8%
Pipeline	-	41	95	114	145	149	107	5.5%
LNG	0	31	82	110	114	130	98	6.1%

* Compound average annual growth rate. ** Industry includes gas used as petrochemical feedstocks. *** Other includes agriculture and any other non-energy use. **** Also covers demand for LNG used as an international marine fuel.

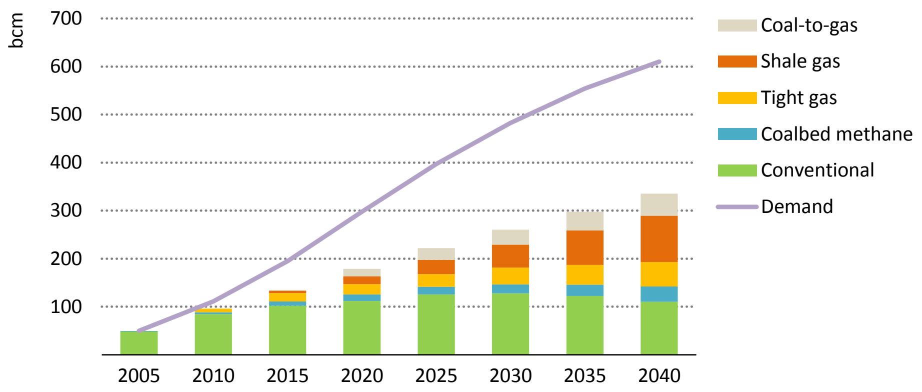
Reserves and resources

China has vast natural gas resources estimated at some 50 trillion cubic metres (tcm) (as of end-2016), most of which falls into the unconventional gas category. It holds 6% of the world's total gas resource, but its estimated shale gas resource of 32 tcm is the largest in the world (almost 15% of the global shale resource). The Tarim Basin located in China's western province of Xinjiang is the largest onshore sedimentary basin in China but there the gas is deep, which means that the Sichuan Basin (in Sichuan province and Chongqing municipality), which also holds large resources, appears more promising. Coalbed methane resources amount to 9 tcm, located in three primary basins: the Junggar, Sichuan and Ordos basins. The Junggar basin is in Xinjiang; the Ordos Basin straddles the borders of Inner Mongolia, Shanxi, Shaanxi, Ningxia and Gansu provinces. Tight gas resources – in Chinese accounting treated as a conventional source – stand at 3 tcm, mostly split between the Ordos and Sichuan basins. Uncertainty about the actual size of the resource, especially the shale gas resources, is considerable: our projections for shale gas production over the next 25 years are only a small fraction of the resource estimate.

Production prospects

China, with production of almost 140 bcm in 2016, is currently the sixth-largest gas producer in the world. Conventional gas production accounts for over 70% of the country's gas output, mainly from the Sichuan, Ordos and Tarim basins (accounting between them for around 90% of conventional output) together with some offshore production, but this is set to change markedly. Between now and 2040 almost all the projected growth comes from unconventional sources, and by 2040 the contribution of conventional gas to the country's output of 335 bcm is down to a third (Figure 14.16). The 13th Five-Year Plan targets an increase in conventional gas production to 120 bcm by 2020 and, based on remaining resources, increasing conventional output slightly by 2020 appears achievable, but in the longer term, our projections indicate a slight decline to 110 bcm in 2040. Achieving these production levels is likely to depend on the announced upstream, pricing and pipeline reforms being fully implemented.

Figure 14.16 ▷ Natural gas demand in China and production by type in the New Policies Scenario



Growth in Chinese gas production is underpinned by unconventional gas, as output from conventional fields stagnates, but production cannot keep up with soaring demand

Expectations are much higher for unconventional gas. The 13th Five-Year Plan set a target of output from all unconventional sources to reach 110 bcm by 2020, a sharp rise from 38 bcm in 2016. However, production levels – especially for shale gas – have been below this trajectory to date and the official targets for shale gas have been revised in response. In mid-2012, national targets were set at 6.5 bcm by 2015 and 60-100 bcm by 2020. In late 2014, slow progress in expanding shale output saw the 2020 target revised to 30 bcm, where it remains in the current five-year plan. The revision was motivated by mixed initial well results in many parts of the Sichuan Basin, which highlighted some geological challenges as well as inconsistent flow rates. The exceptional performer is Sinopec's Fuling development in Sichuan, where cumulative output has reached 10 bcm from 250 production wells, and is on track to hit the targeted annual production of 10 bcm by the end of 2017 (around two-thirds of China's proven shale gas reserves are in Fuling). But prospects elsewhere in the region are proving more difficult to commercialise, suggesting that Fuling's performance may turn out to be more the exception than the rule.

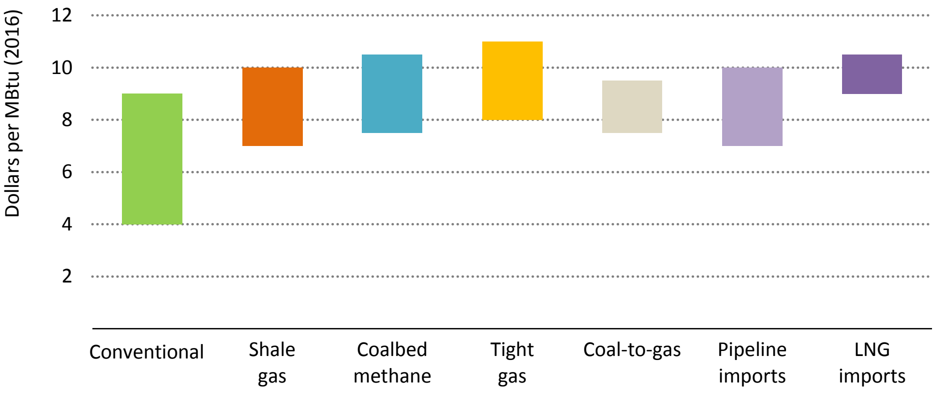
Although shale gas production in the Sichuan Basin and elsewhere represents a significant potential opportunity, there are various points of difficulty that affect its prospects:

- The current economic incentives to pursue shale gas are relatively weak, with a few exceptions. Costs, including drilling, are still high in most areas and bringing them down requires a surge in upstream activity and momentum; this will only be generated if the upstream becomes more diverse and competitive. With production costs around $7-10/MBtu, subsidy levels appear inadequate to drive the necessary activity surge and the associated lowering of costs (Figure 14.17).
- Today's market conditions provide a ready alternative source of gas in the form of imported LNG, close to demand centres, and in practice the main Chinese companies have over-contracted gas. The low price environment has also taken a toll on the capital available for upstream spending.
- The ability of new entrants to make their mark in the gas sector is likely to improve as regulatory reforms proceed and third-party access is established, but for the moment, they have difficulties marketing any output to end-users via the existing pipeline networks.
- The Sichuan Basin is difficult terrain for intensive drilling – hilly, densely populated and heavily cultivated – and requires close attention to the social and environmental aspects of shale gas production to avoid the potential for friction with local communities. Water availability may also prove a constraining factor in Sichuan, given potential competition with agricultural users; it will certainly be an issue if, and when, activity moves to the arid Tarim Basin in the west.
- There are also geological issues: many of the Chinese plays are located at greater depth than those in North America, which creates additional technical challenges as well as longer drilling times. Some plays also have a high clay content, which is difficult to fracture effectively, resulting in lower recoverable volumes per well.

These factors suggest strongly that the reforms to the gas industry which have already been announced may be more effective in increasing output than measures such as subsidies, which are in any event time limited and set at rather low levels given the current costs of shale. Our *Outlook* suggests that it will be the middle of the next decade before shale gas production accelerates, reaching nearly 50 bcm by 2030 and 100 bcm by 2040. Shale gas is the primary source of gas production growth in China and accounts for nearly 30% of output in 2040: as such, the prospects for overall gas production in China depend heavily on the prospects for shale.

Tight gas is another source of unconventional gas production in China, currently accounting for almost 15% of national gas output. The contribution of tight gas increases gradually to more than 50 bcm. CNPC leads production at the Sulige field, a joint venture between CNPC and Total, in the Ordos Basin, the largest gas field in China and a major factor in the recent expansion of gas output. Shell is working with CNPC at the Changbei development, also in the Ordos Basin. The technologies for tight gas extraction, including horizontal drilling and hydraulic fracturing, are relatively mature in China, and this provides a good basis for further development and increasing production over the *Outlook* period.

Figure 14.17 ▷ Indicative production cost ranges for different sources of gas in China, 2025



The costs of Chinese domestic gas production are uncertain and fall in a wide range; the price of imported gas sets a ceiling for commercially viable domestic developments

Coalbed methane is another source of unconventional gas supply in China. The 13th Five-Year Plan sets an ambitious target of 24 bcm of coalbed methane production by 2020: just over a third of this is targeted to come from underground extraction, with the rest coming from coal mine methane, gas that is freed in the process of coal mining or from decommissioned collieries and then collected. Making use of methane emissions from coal mines that would otherwise leak into the atmosphere has important environmental benefits, as methane is a particularly potent greenhouse gas (see Chapter 10). While geological and other technical challenges are important, there is also the challenge of disentangling the respective rights of coal producers and coalbed methane extraction: the 32 bcm of production that we project in 2040 assumes that these challenges are successfully overcome.

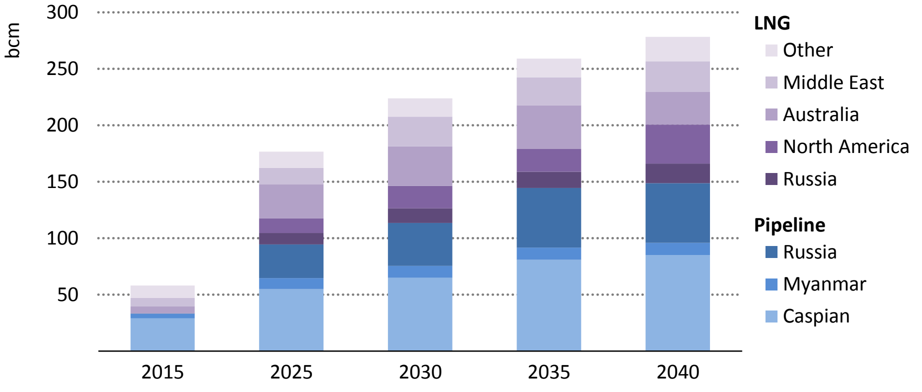
The 13th Five-Year Plan sets out an intention to expand the production of synthetic natural gas from coal (coal-to-gas), with a target of 17 bcm of installed gasification capacity by 2020 – a marked increase from the 5.1 bcm operational in early 2017. Five key projects, located in the coal-rich provinces of Xinjiang, Shanxi, Inner Mongolia and Anhui, have been identified for development in the coming years. The commercial viability of coal-to-gas projects has suffered recently in light of the ample availability of gas and low spot prices for LNG, but coal gasification projects can claim to bring strategic benefits such as security of supply and regional development, as well as monetising coal reserves that might otherwise be hard to commercialise. When located close to low-cost coal deposits, synthetic natural gas facilities can produce gas at $7.5-9/MBtu. Based on current policy intentions, we project growth in coal-to-gas output from 2 bcm in 2016 to 25 bcm in 2025 and then to

50 bcm by 2040. However, the environmental risks from synthetic gas production are substantial, ranging from impacts on water resources to local air pollution and thus need to be carefully regulated. In our judgement, the future of coal-to-gas is closely linked to the success of unlocking China's vast unconventional gas reserves. A more upbeat outlook for the production of shale gas than projected in the New Policies Scenario would diminish the economic and policy rationale for coal gasification projects, and vice versa.

14.4.2 Gas imports

Despite rapid increases in Chinese gas output, the upstream cannot keep up with growth on the demand side, leading to a growing gap between domestic production and consumption that has to be met through imports. Chinese gas imports grow from 70 bcm in 2015 to some 280 bcm in 2040, making China the second-largest gas importer in the world after the European Union (Figure 14.18). Import dependency increases from around 35% today to just under 50% in 2040.

Figure 14.18 ▷ Natural gas imports in China by exporter and transport mode in the New Policies Scenario



China's gas imports grow strongly and supplier diversity increases as new pipeline projects come online and new LNG exporters enter the market

With energy security interests in mind, we assume that import needs are met through a careful balance between different sources of pipeline imports and LNG. Diversity of suppliers grows markedly over the next 25 years, not least as Russia becomes a key pillar of gas supply and as North American LNG exports increasingly find their way to China, mostly indirectly through aggregators. The commissioning of the eastern route of the Power of Siberia pipeline creates a first link between China and Russia in the early 2020s, and with the assumed expansion of gas pipeline trade in the 2030s (either via a reinforced eastern link or the Altai route into western China) Russia establishes a strong foothold in the growing Chinese gas market. The eastern route pipeline is under construction on both sides of the border and will be instrumental in delivering gas to China's north-eastern provinces, helping to reduce coal use in the heating sector and industry and to improve air quality.

Turkmenistan is already well connected to China with three large-scale pipelines currently operational (Lines A, B and C) and a fourth line (Line D) planned. The utilisation of the pipelines to Central Asia has however been below the capacity of the system, and work on Line D has been suspended. In the New Policies Scenario, we assume that Line D eventually comes to fruition in the 2020s and that volumes imported to China through the existing lines get closer to making full use of pipeline capacity. Myanmar is currently sending smaller volumes of gas into South China and is projected to gradually increase its shipments over time. Total imports to China by pipeline, from all sources, rise from around 40 bcm in 2016 to 150 bcm in 2040.

China currently has 17 regasification terminals with a combined capacity of some 70 bcm in operation and another six facilities totalling over 20 bcm under construction. The terminals are far from being fully utilised, but imports picked up in 2016 and 2017 after sluggish growth in 2014 and 2015. With plenty of LNG currently available on the international market, the hopes of many exporters rest on China absorbing growing volumes of gas in the coming years and helping to bring the market back into balance. LNG imports are projected to quadruple over the projection period, reaching 130 bcm in 2040. China will take a major role in rebalancing and shaping the future LNG market: by the end of the *Outlook* period, it overtakes Japan to become the largest LNG importing country in the world. Chinese LNG buyers thus have substantial leverage in negotiating contract terms and prices (a recent initiative to create a buyers alliance between CNOOC, JERA and Kogas for the joint procurement of LNG hints in this direction, although it is difficult to assess at this stage what may come of this potential alliance).

Third-party access to regasification facilities and transmission infrastructure would be a key enabler of sustained LNG import growth. It would have the potential to help boost diversity and competition in the gas market, as well as to improve the utilisation of the existing import facilities and to stimulate development of China's domestic gas network. Many (mostly private) companies currently ship their LNG by road for want of infrastructure (some sources suggest that nearly 10% of the LNG consumed in China has been delivered by truck). Private companies are also seeking to build their own regasification terminals in response to incumbents trying to keep newcomers out of the market. In addition, there are already some small-scale liquefaction facilities in operation, particularly in southwest China (Box 14.3). LNG is an ideal source of supply along China's coastline and currently often a cheaper option than bringing gas from distant pipeline border-crossing points or domestic production hubs. However, as gas prices increase over time, LNG becomes a more costly source of supply, and projected LNG import volumes are particularly sensitive to trends in end-use sectors and in the upstream. A key advantage of LNG remains its flexibility to balance – especially seasonal – demand swings or fluctuations in domestic production.

Box 14.3 ▷ Domestic small-scale liquefaction in China

Small-scale liquefaction plants play a notable but sometimes overlooked role in the China's gas market. Typically set up in areas where the gas network is less developed, and during periods when LNG prices compare favourably with pipeline gas, the small-scale LNG supply chain started to take shape in China a decade ago. It has since grown quickly into a sizeable industrial chain with mature business models. China's small-scale LNG liquefaction capacity is now around 24 million tonnes, spread across more than 160 plants; with output of 8.6 million tonnes in 2016, the size of this market has more than quadrupled in size since 2011. Production capacity varies by facility, ranging from 8 000 tonnes per year to 1.2 million tonnes per year. Around 90% of the liquefaction plants have capacity of less than 0.3 million tonnes per year. Private companies own over 80% of the capacity.

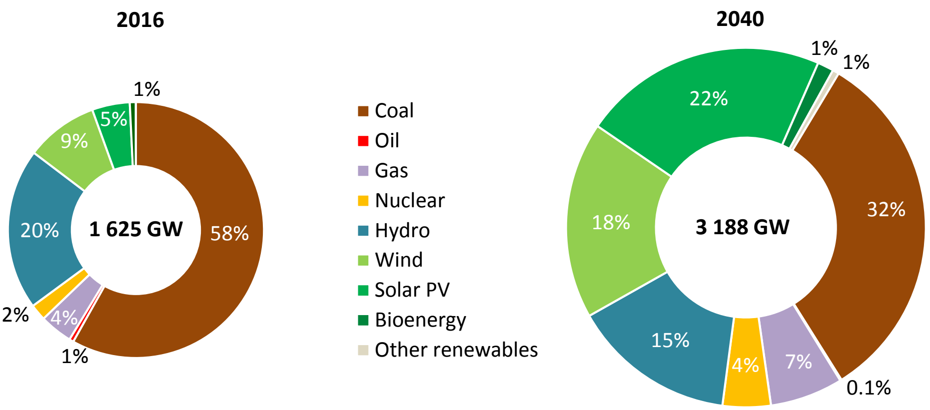
The sources of gas for the small-scale LNG facilities are mainly associated gas and unconventional gas produced in southwest China, where the scattered and relatively small scale of production undercuts the commercial case for pipelines, but they could gradually expand to include coalbed methane in the future. Small-scale LNG can provide a valuable complement to pipeline gas, broadening the consumer base and the range of applications for which gas is used. Clients of small-scale LNG facilities range from those who deal with peak shifting and emergency response in cities such as Shanghai, to urban and rural residents in remote areas with no pipeline coverage. It also extends to LNG filling stations that provide an alternative fuel for trucks, to distributed combined heat and power (CHP) plants for public buildings and industries. The flexibility and liquidity that small-scale LNG brings to the gas market is expected to boost overall gas consumption: the 13th Five-Year Plan for gas also expressly promotes small-scale LNG in rural areas as a way to combat local air pollution.

14.5 Renewables

China is the world's largest renewable market. It added net electricity capacity of 68 GW in 2016 (more than 40% of global renewable capacity additions) and continued strong growth in 2017. Technology-specific feed-in tariffs and national targets drove the majority of this increase. China saw higher levels of growth than any other country in all three major renewable technologies – solar PV, onshore wind and hydropower – and its renewable electricity generation output grew by an estimated 12% to reach 1 577 TWh in 2016, accounting for more than a quarter of total generation. Hydropower contributed most to China's overall renewable generation output, but wind and solar generation are growing rapidly (by 30% and 45% year-on-year in 2016, respectively).

In the New Policies Scenario, the expansion of renewables is largely concentrated in the power sector, with their share of capacity rising to almost 60% of the total by 2040 (Figure 14.19). While the use of hydropower and bioenergy increases over the *Outlook* period, the growth of wind and solar PV account for the majority of this increase. Generation output from these two technologies alone multiplies seven-fold, going from 5% of electricity production to more than 20% (from 310 TWh to 2 400 TWh). The share of heat coming from renewables over the period to 2040 also grows from a little over 1% to almost 5%. Consumption of biofuels in the road transport sector rises from 2.1 Mtoe today (around 45 kboe/d) to 22.5 Mtoe in 2040 (approaching 500 kboe/d).

Figure 14.19 ▷ Installed power generation capacity in China in the New Policies Scenario



Low-carbon technologies comprise 60% of total capacity in 2040 and overtake fossil fuels by 2030

14.5.1 Bioenergy

China's biomass energy resources come from agricultural, residential and industrial wastes, energy crops and plantations. Each year, the country is estimated to produce almost 300 million tonnes of crop straw waste and 300 million tonnes of forestry waste. China is in the midst of a large shift in its bioenergy use, with the balance shifting away from the traditional use of biomass by households and towards modern utilisation, notably for power generation. Consumption of solid biomass for cooking and heating in households has been falling in recent years but is still widespread. Up to one-quarter of the population is estimated to rely in part on biomass for cooking, although there are uncertainties about the data. Its use is in decline because of a range of factors, including an increase in the use of LPG and natural gas for cooking; a ban on the combustion of coal and wood in homes in cities as a result of air quality concerns; and the rapid expansion of natural gas infrastructure in urban areas.

The 13th Five-Year Plan on Bioenergy was released in December 2016 and sets out detailed targets for bioenergy. In the New Policies Scenario, which draws on this plan, the modern uses of bioenergy all expand, while consumption of solid biomass in the buildings sector declines by almost two-thirds to 28 Mtoe. The largest increase comes in the use of bioenergy for centralised production of power and heat. Installed bioenergy electricity generation capacity rises to almost 50 GW, from 12 GW in 2016, producing more than 300 TWh by the end of the projection period. In end-use sectors, direct consumption of bioenergy rises substantially in the industrial sector (to more than 40 Mtoe by 2040), providing a valuable source of high-temperature process heat as well as a low-carbon option to reduce reliance on coal in this sector.

The other direct use of bioenergy in China is as a transport fuel. The policies that China has implemented so far to help develop biofuels have resulted in the country becoming the world's third-largest ethanol producer, albeit some distance behind the United States and Brazil. Today's consumption of biofuels is around 45 kboe/d: ethanol contributes some 30 kboe/d (about 3 billion litres per year) and biodiesel provides the remainder, and the Chinese government has set ambitious 2020 production targets of 4 million tonnes (3.8 Mtce) for ethanol and 2 million tonnes (3 Mtce) of biodiesel. In our projections the ramp-up in biofuel use is less steep but still significant: by 2040, consumption of biofuels is around ten-times today's level, with 260 kboe/d of ethanol for road transportation; 220 kboe/d of biodiesel, mostly for the freight sector; and a small amount of biojet kerosene that is used for domestic aviation.

14.5.2 Hydropower

Hydropower is the largest source of renewable energy in the power sector in China, and remains so through to 2040 in the New Policies Scenario (although generation from wind comes close by 2040). China accounts today for around one-quarter of global hydropower capacity and added 12.6 GW of new capacity in 2016, including 3.7 GW of pumped storage. This took its total installed capacity to 332 GW, including 26.7 GW of pumped storage. It generated nearly 1 200 TWh from hydropower in 2016, equivalent to twice the total electricity generated in Germany. The 22.5 GW Three Gorges Dam Project on the Xilingxia Gorge along the middle reaches of the Yangtze River in Hubei province, the largest hydro generating facility in the world, accounts for around 7% of the country's total hydropower capacity. Other large projects also owned by the state-owned China Three Gorges Corporation include the Xiluodu project, located on the Jinsha River in Sichuan and Yunnan provinces in the West region, which has a total capacity of 13.9 GW; and the Xiangjiaba project in Sichuan province, which has a total capacity of 6.4 GW.

The largest project currently under development is the Wudongde Hydropower Project, located in the lower reaches of the Jinsha River, in Yunnan and Sichuan provinces. This 10.2 GW project, scheduled for completion in 2020, will be the fourth-largest hydroelectric generating plant in the country. There are also many small-scale hydropower plants in operation. In December 2016, the Ministry of Water Resources adopted "guidelines on promoting the development of small hydropower plants", which call for standards to improve small hydropower plant management and a system of incentives for new small hydropower installations.

China's most recent survey of hydropower, published in 2016, identified a technical exploitation potential of 660 GW or 3 000 TWh/year. In the 13th Five-Year Plan for Renewable Energy, the government established a goal of 340 GW of hydropower generating capacity by 2020. The plan also focuses on increasing pumped storage capacity, with the aim of having 40 GW total pumped storage capacity by 2020. In the New Policies Scenario, hydropower capacity expands by just under 50% to reach 490 GW in 2040, producing some 1 500 TWh of electricity. The rate of expansion is constrained by growing difficulty in finding suitable (and available) sites for new hydropower, meaning that the overall share of hydropower in China's electricity generation falls from 20% today to 15% in 2040. As is the case with some other renewables, bringing electricity generated from inland hydropower centres to load centres on the east coast requires a major expansion of transmission networks.

14.5.3 Solar

Solar energy is emerging as a major pillar of China's future energy mix and a technology area in which China is playing a leading role. The recent deployment record is impressive. Solar PV capacity in China grew to 77 GW in 2016, an increase of 34 GW compared to 2015, accounting for almost half of global capacity additions over the year. This was easily a record expansion of solar PV by one country in a single year (although the signs are that 2017 was another very strong year for Chinese solar PV additions). At present, utility-scale projects dominate the market (90%) and commercial/industrial applications account for most of the remainder: the residential segment remains small. The top-five provinces in terms of installed capacity of solar PV in 2016 are Xinjiang, Gansu, Qinghai and Inner Mongolia in the West region and Jiangsu in the East region (Table 14.6).

Table 14.6 ▷ Total installed solar PV capacity by province at year-end 2016

Rank	Province	Installed capacity (GW)
1	Xinjiang	8.6
2	Gansu	6.9
3	Qinghai	6.8
4	Inner Mongolia	6.4
5	Jiangsu	5.5
6	Ningxia	5.3
7	Shandong	4.6
8	Hebei	4.4
9	Anhui	3.5
10	Zhejiang	3.4
	Others	22.2
	Total	**77.4**

Source: NDRC.

Assessments of China's solar PV potential vary but the Chinese Energy Research Society estimates its technical potential to be around 2 200 GW. Most of this resource is located is the West region, on the Qinghai-Tibet Plateau, which is largely unconnected to the electricity system. The 13th Five-Year Plan for Renewable Energy established the goal of at least 105 GW of installed solar PV capacity by 2020, with distributed PV accounting for 60 GW and utility-scale PV for 45 GW. Updated guidelines for the implementation of the 13th Five-Year Plan for Renewable Energy, which contained targets for each province, were published in July 2017. Indications are that a rapid pace of deployment continued into 2017: by the middle of the year, more than 24.4 GW (17.3 GW utility-scale and 7.1 GW distributed) of new solar PV capacity had been added, bringing total capacity up past 100 GW. This is already within sight of the 2020 capacity target, with distributed generation also starting to pick up for the first time. In the New Policies Scenario, total solar PV capacity continues to grow rapidly and reaches 740 GW by 2040, contributing around 10% of China's total electricity generation, from 1% today. Continued falls in the levelised cost of electricity from utility-scale solar PV makes this the cheapest form of new power generation in China by 2030. By the end of the projection period solar PV costs are also lower than the operating costs of existing coal-fired power plants. However, the pace at which solar PV develops at scale is not only a question of relative costs, but will also depend on the design and operation of the electricity system and network infrastructure (discussed in detail in Chapter 13).

In addition to solar PV, China is also a leader in the manufacture and deployment of solar hot water heating systems. Solar thermal heat production has increased by more than 150% since 2010; this rate of growth slows in our projections as a result of recent changes in policy support (see Chapter 13), but heat output nonetheless doubles to 50 Mtoe in 2040. The deployment of concentrating solar power (CSP) is also increasing in China, and twenty large-scale projects are expected to be completed by the end of 2018 in order to benefit from a special feed-in tariff. The 13th Five-Year Plan for Renewable Energy established a goal of 5 GW for CSP by 2020, a target achieved in our projections, with CSP in 2040, at 60 TWh, providing just above 0.5% of total generation.

14.5.4 Wind

Wind power is another rising star in China's energy mix. Wind power installations are located in all provinces/regions. As of 2015, the top-five provinces in terms of installed capacity were Inner Mongolia, Xinjiang, Gansu and Ningxia, located in the wind-rich West region along with Hebei in the East region. These five provinces combined accounted for 52% of the country's overall wind power capacity but, as with deployment of solar PV, are located far from the country's main load centres. In 2016, wind power generated 242 TWh of electricity, making it the third-largest power generation source after coal and hydropower, providing 4% of China's electricity. The capacity installed in 2016 meant that China surpassed the European Union in terms of cumulative onshore wind capacity. China also had 1.6 GW of offshore wind (second in global terms after the European Union). As with solar PV, curtailment of output because of network limitations and power balancing issues is a critical challenge facing the wind industry in China (see Chapter 13).

Table 14.7 ▷ Installed wind power capacity by province year-end 2016

Rank	Province	Installed capacity (GW)
1	Inner Mongolia	25.6
2	Xinjiang	17.8
3	Gansu	12.8
4	Hebei	11.9
5	Ningxia	9.4
6	Shandong	8.4
7	Shanxi	7.7
8	Yunnan	7.4
9	Liaoning	7.0
10	Heilongjiang	5.6
	Others	35.3
	Total	**148.7**

Source: NDRC.

China enjoys abundant wind resources with substantial development potential. Estimates of China's onshore wind power potential vary greatly, depending on different assumptions about efficiency, hub heights, turbine size and land-use considerations. Since the 1970s, China has conducted four nationwide wind resource surveys. The first three were mainly resource investigations, while the fourth was a detailed investigation and assessment of national wind resources. For this detailed survey, the China Meteorological Administration (CMA) erected 400 wind towers with heights of 70 metres (m), 100 m and 120 m, and established a national wind measurement network. CMA also developed a wind energy numerical simulation and evaluation system (WERAS/CWERA) to carry out historical data filtering, numerical simulation and geographical information system analysis. For areas with average wind power density of more than 300 watts per square metre, and factoring in geographical constraints, China's onshore potential was estimated to be 2 000 GW at 50 m height, 2 600 GW at 70 m and 3 400 GW at 100 m. Similar analysis was conducted to assess the offshore potential: 500 GW of exploitable potential was identified at water depths of 5 m to 25 m and at 100 m height.

In the 13th Five-Year Plan for Renewable Energy the goal for wind energy is 210 GW of installed capacity and 420 TWh of electricity production by 2020. Updated guidelines for the implementation of the 13th Five-Year Plan for Renewable Energy were published in July 2014, which contained targets for each province on the scale of new wind power (and solar PV) developments. In addition, nine provinces have adopted provincial level wind energy policies to stimulate the development of wind energy. In the New Policies Scenario, wind power makes a major contribution to China's power generation system, with its share of generation rising to 13% in 2040 (1 350 TWh) as total installed capacity increases to 600 GW (of which around 40 GW is projected to be offshore).

14.5.5 Geothermal

Geothermal district heating is a major element of China's efforts to improve urban air quality. In 2017, NDRC, NEA and the Ministry of Land and Resources issued the first 13th Five-Year Plan for Geothermal Energy, which signalled the opening of urban heat markets to geothermal companies. This implies that the sector could eventually get state subsidies to help it achieve its targets. According to government geothermal energy plans, geothermal heating will reach 450 million square metres (m^2) by 2020 in the Beijing-Tianjin-Hebei region alone, which would account for around 20% of space heating consumption in the area (IEA, 2017c). In our projections, the use of direct geothermal energy in the buildings sector more than triples from its current level, reaching 14 Mtoe by 2040.

14.6 Nuclear

China's 13th Five-Year Plan on Energy Development sets a goal for non-fossil fuel in energy consumption of more than 15%, and nuclear energy is set to play an important part in the achievement of this goal. Nuclear generation has expanded rapidly over the last decade: from 53 TWh (or 2% of total generation) in 2005, the contribution of nuclear plants rose to 213 TWh (or 3.5% of total output) by 2016, including a near doubling in the last 11 years. As a result, the nuclear power fleet in China is relatively young, with almost 75% built within the last decade. Of the approximately 64 GW of new nuclear capacity under construction worldwide, one-third is in China. In all, the country has 36 nuclear power reactors in operation, 21 under construction and 31 more about to start construction.[9] In the New Policies Scenario, nuclear generation increases five-fold, with generation growing to 1 100 TWh by 2040 (11% of the total).

China is pursuing a dual objective in nuclear technology: to adopt a standardised technology for long-term nuclear development, and to develop the technology needed for this in China, so that it becomes self-sufficient in reactor design and construction, as well as in other elements of the fuel cycle. To achieve this, extensive reliance was placed on technological transfers from leading nuclear technology developers/owners and the accumulation of experience through construction and operation of different reactor designs. China has so far adopted French, Russian and indigenous pressurised water reactors (PWR), as well as Canadian pressurised heavy-water reactors. The reactor units currently under construction belong to the more advanced Generation II and Generation III technology. China is also investing significant resources in the development of small modular reactor (SMR) technology, and completed the construction of the world's first high-temperature gas-cooled reactor pebble-bed module (HTR-PM) demonstration power plant in June 2015: the 210 MW unit is targeted at off-grid applications such as cogeneration, heat and hydrogen production.

9. According to the IAEA (IAEA, 2017), of the 21 reactors under construction in China, 20 are PWR technology of 21.4 GW of capacity and one is a high-temperature gas-cooled reactor (210 MW).

The drive towards self-sufficiency includes not only nuclear power plant design but also the production of the fuel. Nonetheless, China still relies to some extent on foreign suppliers for all stages of the fuel cycle, from uranium mining through fabrication and reprocessing, but mostly for uranium supply (WNA, 2017). As the country builds new reactors, it has invested in a number of domestic projects to meet its needs. Government policy is to obtain about one-third of uranium supply domestically, one-third from Chinese equity in foreign mines and one-third on the open market. Over time, China expects to become self-sufficient in other stages of the fuel cycle too. With 58 reactors expected to be in operation by 2020, uranium demand is expected to be over 12 000 tonnes of uranium (tU) and to reach between 12 300 tU and 16 200 tU by 2030 (NEA/IAEA, 2016).

The China National Nuclear Corporation (CNNC) maintains a monopoly on the nuclear fuel cycle and is the only supplier of domestic uranium at present (its output was estimated at 1 616 tonnes of uranium in 2015, or 2.6% of total world output). China Nuclear Uranium Corporation, a subsidiary of CNNC, operates the existing mines. China has approximately 272 500 tonnes of known recoverable resources of uranium, amounting to 4% of global reserves, and a large exploration effort has been made in recent years, led by CNNC's Geological Survey Bureau and the Beijing Research Institute of Uranium Geology, to underpin increases in domestic supply. These efforts have focussed on the Xinjiang and Inner Mongolia provinces and in southern China. In 2012, large deposits were discovered in Daying, Inner Mongolia, and the basin is expected to become the country's largest uranium resource (WNA, 2017).

China imports uranium from Australia, Canada, Kazakhstan, Namibia, Niger, Russia and Uzbekistan. In 2016, it imported 7 115 tU compared with 5 270 tU in 2015. With the likelihood of higher levels of imports in the future, CNNC established the China Nuclear International Uranium Corporation (SinoU) to acquire equity stakes in uranium resources abroad. It has acquired assets in Niger, Namibia and Kazakhstan. Another Chinese company, Sinosteel, has uranium assets in Australia and is involved in exploration projects in Canada and Kyrgyzstan, while CNNC itself has assets in Mongolia. China General Nuclear Power (CGN) has also been active in securing foreign supplies of uranium in Kazakhstan, Namibia and Uzbekistan. Information about China's conversion capacity is very limited, but a number of conversion plants are operating and the country plans to build more plants. China has enrichment capacity located in Shaanxi and Gansu provinces, and the country aims to develop a fully independent enrichment capability including research and development, engineering, manufacturing and operating (WNA, 2017).

14.7 Investment

One-of-every-five dollars invested today in the global energy sector goes into China. Investment into China's energy supply and infrastructure in 2016 was around $275 billion, with an increasing share of this directed to low-carbon electricity supply and electricity networks. The need to mobilise capital on this scale eases somewhat later in the period to 2040 in the New Policies Scenario, in line with a slower pace of expansion in energy demand. However, China maintains and strengthens the shift towards investment in natural gas and low-carbon sources of supply (Table 14.8).

Table 14.8 ▷ Investments in energy supply in China in the New Policies Scenario, 2017-40 (billion $2016)

	Annual averages			Cumulative
	2010-2016	2017-2025	2026-2040	2017-2040
Power sector	**171**	**197**	**180**	**4 467**
Coal	35	12	4	171
Gas	3	5	3	82
Nuclear	7	16	11	304
Hydro	32	21	21	500
Other renewables	45	63	64	1 525
T&D	49	79	78	1 882
Oil	**58**	**33**	**28**	**720**
Upstream	40	20	22	509
Transport / refining	18	13	6	211
Gas	**20**	**29**	**39**	**796**
Upstream	14	20	24	540
Transport	6	10	11	256
Coal	**33**	**13**	**17**	**382**
Mining	20	11	17	353
Infrastructure	14	2	1	29
Biofuels	**1**	**1**	**2**	**32**
Total supply	**283**	**273**	**262**	**6 396**

Note: T&D = transmission and distribution.

The power sector dominates overall energy supply investment, but a striking feature of the projections is the fall in spending on new coal-fired power plants: this collapses from $35 billion a year on average between 2010 and 2016 to $4 billion a year during the period 2026-40. In the period after 2025, well over 80% of spending on new generation capacity goes to renewables (70%) or nuclear (10%). The other notable feature of power generation investment is spending on T&D networks, which averages almost $80 billion per year throughout the period to 2040. China has already invested heavily in building ultra-high voltage direct current (UHVDC) lines and it plans to have 23 lines in operation by 2030. New UHVDC lines will strengthen China's capacity to move huge volumes of electricity from resource-rich inland provinces to the main population centres nearer the coast, and increasing its ability to handle expanded deployment of wind and solar PV.

In the upstream, investment in China's oil sector picks up from its current lows as oil prices recover, but remains around $20 billion on average over the period to 2040, below the amounts committed by companies in the early 2010s. By contrast, average annual investment in upstream gas developments rises substantially compared with historical levels, surpassing upstream oil spending as unconventional gas production gains momentum later in the projection period. Spending on new natural gas infrastructure increases steadily as the gas T&D network extends its national reach. Coal mining investment slows over the next ten years, as the sector works off its current overcapacity, but then is projected to grow again as the mines built in the early 2000s starts to reach the end of their operational lifetimes.

A different way to consider the energy investment challenge facing China is to look only at investment in low-carbon technologies (Table 14.9), which is projected to increase rapidly in the coming years. Investment in the power sector (included in energy supply investment in Table 14.8) represents a substantial share of spending, although falling unit costs for some key renewable technologies mean that a given amount of investment is sufficient to procure a larger amount of capacity. There are also major commitments required in the end-use sectors, notably for electric vehicles[10] and for the direct use of renewable energy in industry, for example through the onsite generation of heat from biomass.

Table 14.9 ▷ Investments in low-carbon technologies in China in the New Policies Scenario, 2017-2040 (billion $2016)

	Annual averages			Cumulative
	2016	2017-2025	2026-2040	2017-2040
Power generation*	**100**	**101**	**96**	**2 343**
Renewables	90	84	84	2 026
Nuclear	10	16	11	304
Carbon capture and storage (CCS)	0	0.1	0.8	13.6
End-use sectors	**19**	**43**	**62**	**1 321**
Renewables in industry	1	1	2	37
CCS in industry	0	0.2	0	1.6
Renewables in transport*				
Electric vehicles	4	14	30	581
Renewables in buildings	14	27	30	701
Total	**119**	**144**	**158**	**3 665**

* Included in energy supply investment in Table 14.8.

Another element in China's investment calculation to 2040 – and among the most important – is energy efficiency (Table 14.10). As seen in Chapter 13, China's energy efficiency policies are growing in scope and efficacy. The country has been among the pioneers in energy efficiency regulation, notably for industrial sectors where a mandatory,

10. For electric vehicles, where applicable, the investment cost is the additional cost of an electric vehicle relative to a comparable conventional vehicle.

target-based energy savings programme has been in place since 2006 for the largest energy-intensive enterprises. This programme was expanded to over 16 000 enterprises in 2011. The largest efficiency gains thus far have been in the cement, chemicals and light manufacturing sectors.

Table 14.10 ▷ Investments in energy efficiency in China in the New Policies Scenario, 2017-40 (billion $2016)

	Annual average 2017-2040	Cumulative 2017-2040
Industry	15	344
Transport	51	1 181
Buildings	24	553
Total	**90**	**2 078**

* The methodology for measuring energy efficiency investment derives from the additional expenditure made by households, firms and the public sector to improve the performance of their energy-using equipment above a baseline of efficiency levels in different end-use sectors in 2014.

In the New Policies Scenario, China invests more than $2 trillion in energy efficiency between 2017 and 2040, or an average of almost $90 billion per year. The transport sector accounts for 57% of this investment, with buildings accounting for 27% and industry for 16%. In the transport sector, the investment required to meet fuel-efficiency standards for cars and trucks absorbs 92% of the sector total. Heavy industry (57%) dominates investment in the industry sector, with chemicals attracting the bulk of this, followed by the iron and steel subsector. In the buildings sector, the main focus areas for spending on energy efficiency are insulation (34%) and appliances (19%); almost two-thirds of the total investment goes to the residential sector.

Global implications of energy policy reforms in China

China's choices and how they matter for the world

Highlights

- Over the coming decades, China's energy choices will continue to have profound implications for global markets, trade and investment flows, technology costs and the achievement of shared global goals. But this influence is felt in different ways than in the past. China's energy future will not be a continuation of previous trends.
- In the New Policies Scenario, China overtakes the United States as the largest oil consumer soon after 2030 and its oil imports reach 13 mb/d in 2040; but oil demand growth is larger in India after 2025. Likewise, China remains by far the largest global producer and consumer of coal, but it looms slightly less large as coal use moves into structural decline.
- While oil flatlines and coal declines in China's energy mix, the role of natural gas and of low-carbon technologies expands, with wide-ranging international implications. By 2040, China's total projected gas import requirement of 280 bcm is second only to that of the European Union, making China a linchpin of global gas security. China also leads global clean energy investment in the New Policies Scenario, including in electric cars, batteries, solar PV, wind and nuclear.
- The pace of China's economic transformation is an important uncertainty for global energy markets. Delaying the economic transition in China by ten years and slowing the move away from heavy manufacturing would keep China on a more energy- and CO_2-intensive pathway. In this case, coal demand in 2040 could be up to 850 Mtce (or 35%) above the level of the New Policies Scenario, and oil demand higher by 2.7 mb/d (18%). China would also face lower average wages, a less resilient economy, and higher environmental and health costs.
- On the other hand, the clean energy transition could unfold even faster than projected in the New Policies Scenario, inspired by the aims of China's "energy revolution". In the Sustainable Development Scenario, renewable power capacity in 2040 is more than 20% (or 430 GW) higher than in the New Policies Scenario, and the electric car stock by almost 200 million cars. Gas demand rises by another 10% in 2040, coal demand is cut by half and oil demand by one-third. The benefit for China is a dramatic improvement in air quality and a reduction in fossil-fuel import bills.
- China's future energy pathway will be critical for achieving global climate goals. In the New Policies Scenario, China's energy-related CO_2 emissions per capita peak at about the level of the European Union today; but, by 2040, China still makes up one-quarter of global emissions. A delay in China's economic transformation by ten years and slower energy sector change would raise 2040 CO_2 emissions by 2.7 Gt. A faster transition, as in the Sustainable Development Scenario, could lower them by 5.3 Gt.

15.1 Introduction

The speed and scale of change in the energy sector in China over the last two decades has been without precedent in energy history. How the system evolves further over the next two decades, and what China's energy system will look like in 2040, are vitally important questions for China and the world. In our projections, described in detail in Chapters 13 and 14, we have outlined a possible pathway for China's energy development to 2040, based on in-depth analysis, sector-by-sector and province-by-province, of China's energy policies and reform ambitions. However, the future pathway outlined is far from certain, and in this chapter we explore some of the key uncertainties. Whatever the pathway, the implications of China's choices for the rest of the world will be huge: we also look at the global implications of China's energy development.

The chapter consists of four sections:

- **A recap of key trends in the New Policies Scenario**: this section provides a brief summary of what the future might hold for China's energy sector on the basis of existing plans and announced intentions, putting the main demand and emissions trends in a global context.
- **The possibility of a delayed economic transition**: the New Policies Scenario is based on a shift in the structure of China's economy in the direction of services and light industrial branches. This section combines insights from macroeconomic and energy modelling to explore the implications if such a transition were to be held back by ten years.
- **The possibility of a more rapid clean energy transformation**: the New Policies Scenario does not exhaust China's potential for long-term transformation in the energy sector. This section explores the scope for China to exceed its stated ambitions, with reference to the projections for China in the Sustainable Development Scenario.
- **The global implications of China's energy development**: China's influence in global energy encompasses all fuels and technologies. This concluding section examines how China's interactions with the global energy system vary by scenario, looking at oil, gas and coal markets and low-carbon technologies.

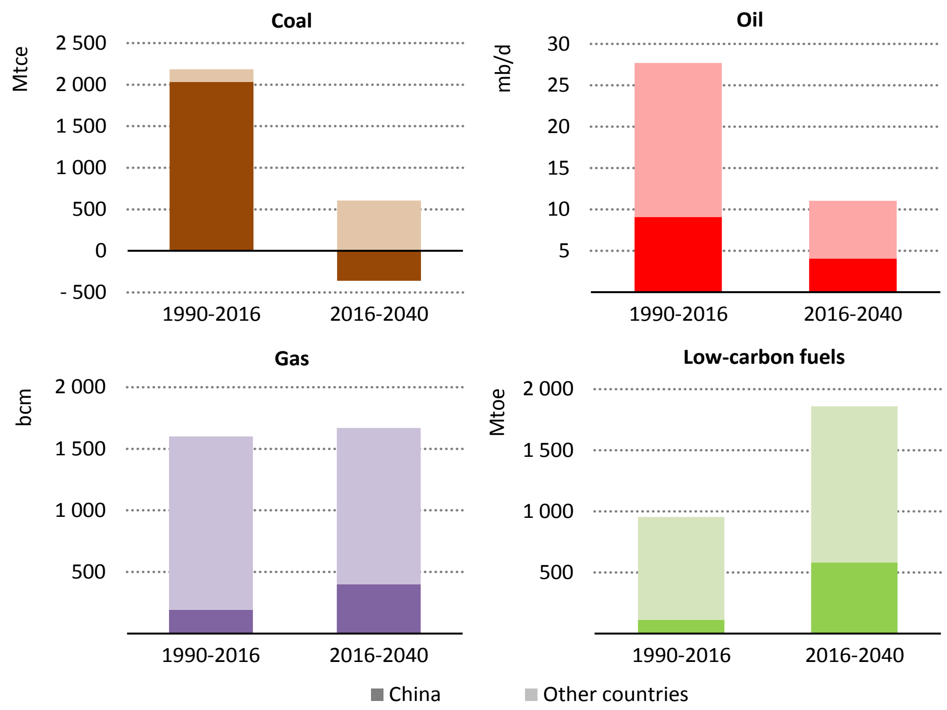
15.2 A recap of key trends in the New Policies Scenario

15.2.1 Demand trends

China has accounted for more than 40% of growth in global primary energy demand since 1990, giving it a defining role in global energy markets. In the New Policies Scenario, China remains an important driver of global energy demand growth to 2040. But China's policy focus is now increasingly on energy efficiency and restructuring its economy, and its share of energy demand growth through to 2040 is reduced to one-fifth of the global total, falling behind that of India.

Across fuels, the most significant change in the New Policies Scenario is China's contribution to global coal demand growth. Since 1990, China's coal demand has risen by 2 000 million tonnes of coal equivalent (Mtce), accounting for more than 90% of global growth (Figure 15.1). With the projected decline in industrial coal use and the plateau in coal consumption in the power sector, China's coal demand is projected to fall to 2040. Nonetheless, by some distance, China remains the largest coal consumer in the world. At more than 2 400 Mtce, China accounts for nearly 45% of global coal demand in 2040, 50% more than India, the world's second-largest coal consumer by that time.

Figure 15.1 ▷ Change in world primary energy demand by fuel in the New Policies Scenario



China shows a diminishing appetite for coal and oil, and a growing appetite for low-carbon technologies and natural gas

Note: bcm = billion cubic metres; mb/d = million barrels per day; Mtce = million tonnes of coal equivalent; Mtoe = million tonnes of oil equivalent.

China has been the main force behind global oil demand growth over the past two-and-a-half decades, accounting for more than one-third of global growth. China's oil demand continues to rise. Propelled by an increase in demand for mobility and road freight transport, China becomes the world's largest oil consumer by the early 2030s, overtaking the United States. But oil demand growth slows gradually over the projection period and more or less reaches a plateau at about this time as gasoline demand from passenger cars peaks due to increasing energy efficiency and the strong market uptake of electric cars. As a result, India becomes the largest source of global oil demand growth from around 2025. Nonetheless, at 15.5 million barrels per day (mb/d) in 2040, China retains its role as the world's largest consumer of oil throughout the projection period.

China is already an important presence in global natural gas markets, even though gas plays a relatively limited role in its current energy mix. Relative to the size of its economy, China's use of natural gas per unit of gross domestic product (GDP) (measured in purchasing power parity [PPP] terms) is four-times lower than that of the United States, the world's largest gas consumer; relative to the size of its population, per-capita use of natural gas is 16-times lower. Gas use rises significantly in the New Policies Scenario, making China an increasingly important contributor to global gas demand: in the New Policies Scenario, one-quarter of global gas demand growth to 2040 is in China, about twice the share of the past two-and-a-half decades. China overtakes the European Union as the second-largest gas consumer in the world by the late-2020s; by 2040, China's gas demand reaches 610 billion cubic metres (bcm), around three-times the level of today.

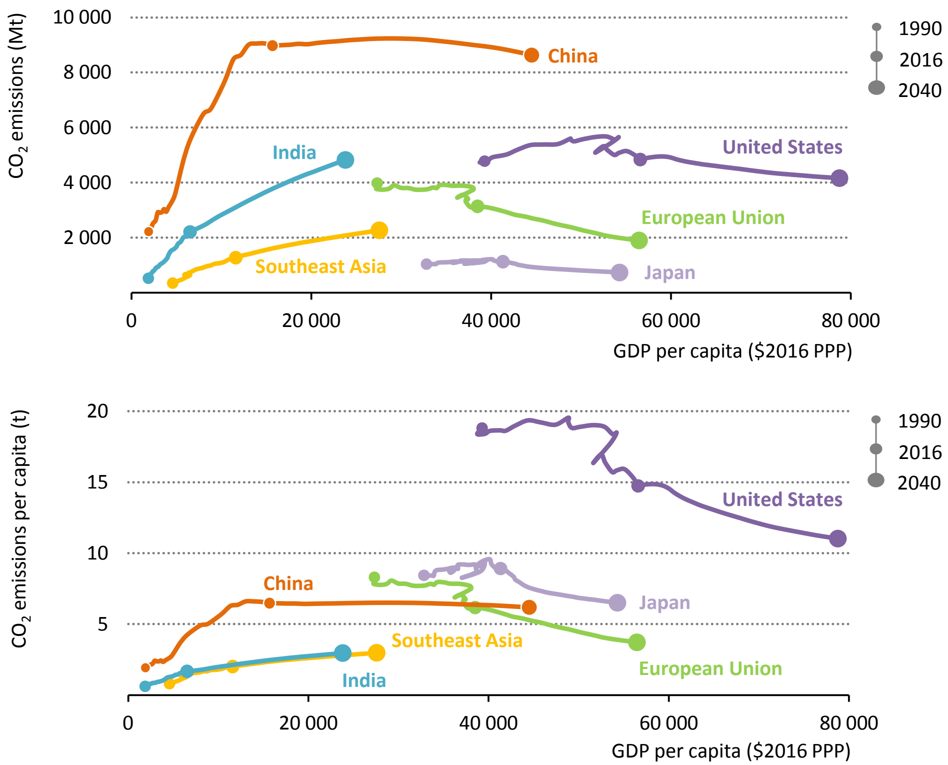
China is already a leading global market for low-carbon technologies, including nuclear as well as renewable energies, which account for 11% of China's energy mix. In the New Policies Scenario, the policy determination to push clean energy technologies makes China the largest global growth market for low-carbon technologies through to 2040: China is responsible for one-out-of-three gigawatts (GW) of global renewables capacity additions; more than 40% of nuclear capacity additions; and around 45% of all electric cars sold on global markets. The result is that, by 2040, the share of low-carbon fuels in China's energy mix rises to around one-quarter.

15.2.2 CO_2 emissions trends

Until 1990, China contributed only around 5% to global cumulative energy-related carbon-dioxide (CO_2) emissions, a similar level as Japan and much less than the United States (around one-third) or the European Union (around 30%). The rapid industrialisation and economic growth of the country since then changed this picture dramatically. Since 1990, China's energy sector has emitted around 138 gigatonnes (Gt) of CO_2 and contributed one-fifth of global energy-related CO_2 emissions, almost the same contribution as the United States over that period. The contribution to global net CO_2 emissions growth over that period was even higher: nearly 60% of the global growth occurred in China. Today, at around 9 Gt (in 2016), China is by some distance the largest source of energy-related CO_2 emissions (Figure 15.2).

The energy sector trends of the New Policies Scenario bring about another remarkable change in China's emissions trajectory, compared with the trends of the past two-and-a-half decades. With its projected slowdown in emissions growth, and a rise in emissions in other countries, China's contribution to global CO_2 emissions growth falls and its CO_2 emissions peak at 6.6 t CO_2 per capita: this is a comparable level to per-capita emissions in the European Union today and below the level at which per-capita emissions peak or have peaked in other major economies. China nonetheless remains the largest global source of CO_2 emissions: in the New Policies Scenario, China emits another 217 Gt of CO_2 through to 2040, about twice as much as the United States and about two-and-a-half times as much as India. By 2040, one-out-of-four tonnes of CO_2 emitted by the global energy sector is from China, and its contribution to cumulative historical emissions, at 18%, overtakes that of the European Union (17%) and is gradually approaching that of the United States (22%).

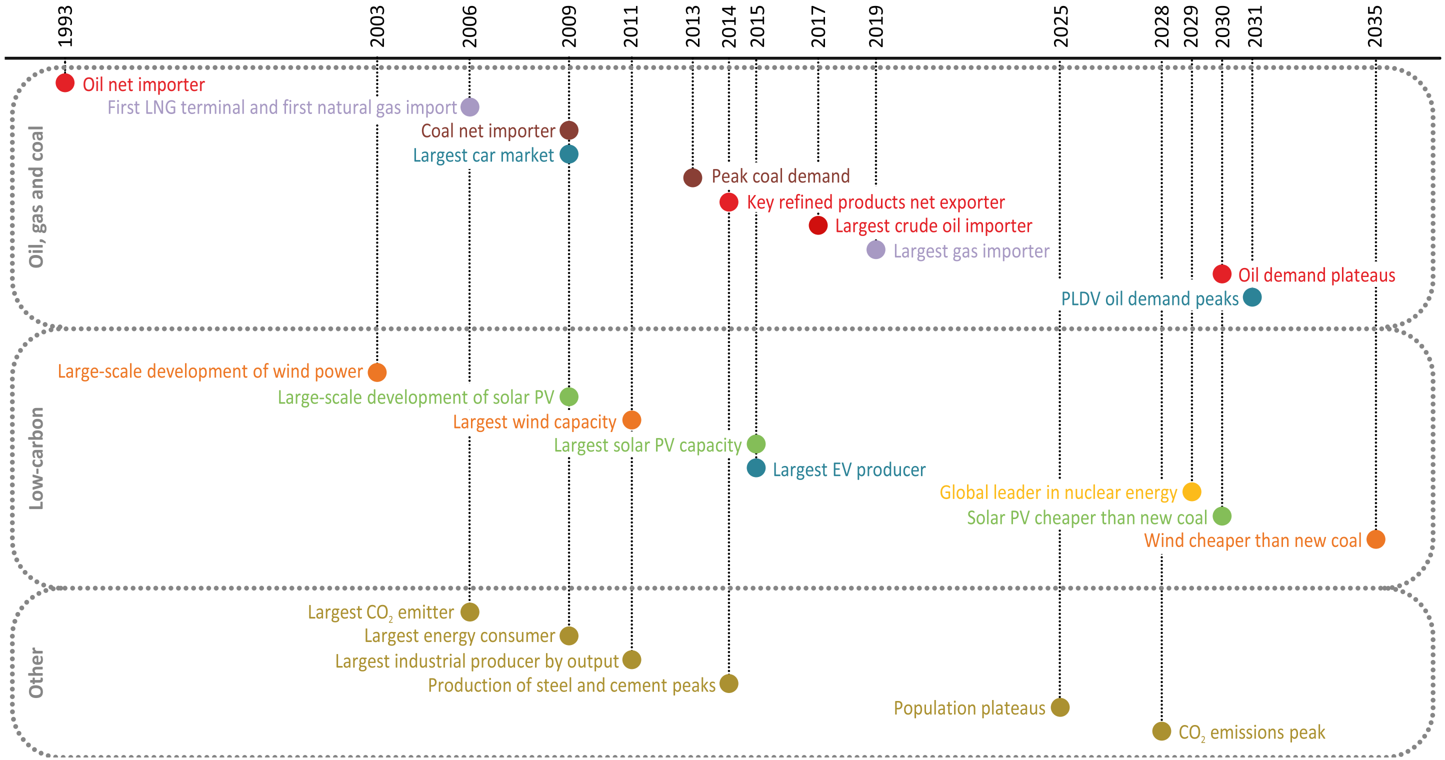
Figure 15.2 ▷ Energy-related CO_2 emissions and per-capita energy-related CO_2 emissions in selected regions in the New Policies Scenario



Per-capita emissions in China peak at lower levels than in most developed regions in the New Policies Scenario, although their absolute level remains the highest

Note: Mt CO_2 = million tonnes of carbon dioxide; t CO_2= tonnes of CO_2; PPP = purchasing power parity.

Figure 15.3 ▷ Timeline of major energy milestones for China, historical and projected in the New Policies Scenario



15.2.3 Key milestones reached in the New Policies Scenario

The energy sector has supported strong economic growth in China over the past decades, which has lifted millions of people out of poverty and made China a key force in global energy markets. Since the country became a net oil importer in 1993, China has become the biggest player across many markets and commodities. The pace of development and growth has often been breathtaking; for example, it took China only eight years to go from beginning large-scale development of wind power to becoming the world leader in terms of installed capacity (Figure 15.3). The New Policies Scenario points to a significant change of direction for energy in China in the coming years, and this has major implications not just for China, but for the world as a whole.

15.3 What if the macroeconomic transition is slower?

Economic growth is an important driver of future energy demand trends in the New Policies Scenario, in China as elsewhere. Assumptions about future economic growth are always subject to uncertainty and, in the case of China, this uncertainty is compounded by the prospect of profound changes in its economic growth model. Today, the share of value added from its services sector in GDP is just above 50%, significantly below the 75% average of advanced economies. It is China's stated goal to increase this, and the 13th Five-Year Plan envisages it rising to 56% by 2020. This section explores the significance of this macroeconomic transition for China's longer term energy sector evolution.[1] It begins with an assessment of the macroeconomic transition in the New Policies Scenario, which assumes that the targeted economic goals are being met. It then discusses the implications of a slower transition, and what such a delay might mean for a range of socio-economic and energy indicators.

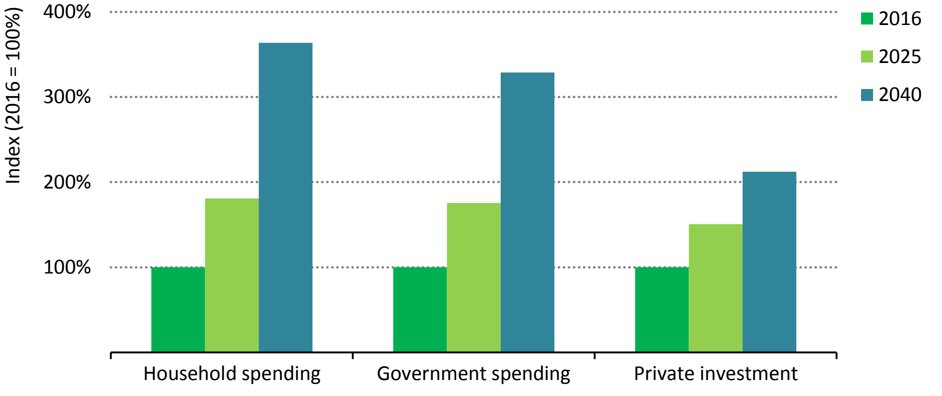
15.3.1 Macroeconomic transition in the New Policies Scenario

The Chinese economy today is highly oriented towards heavy industrial production, infrastructure development and the export of manufactured goods. Its trade balance is strongly positive, which means that its economy is strongly geared towards exports.[2] The New Policies Scenario envisages significant changes in socio-economic trends compared with the recent past. As China's economy continues to mature, GDP growth falls below 5% from the late 2020s onward, while income per capita continues to increase, leading to a growing middle class and a shift in consumer preferences and consumption patterns; at the same time, the population is ageing, leading to an increase in the demand for services such as healthcare. Household and government spending are projected to increase significantly, while investment also continues to grow steadily (Figure 15.4).

1. The macroeconomic analysis in this section is based on simulations coupling the World Energy Model (WEM) with the OECD ENV-Linkages model, calibrated to the scenarios presented in this *Outlook*. For more details about the OECD ENV-Linkages model, refer to the documentation in Chateau, Dellink and Lanzi (2014). See *World Energy Outlook-2012* for additional details about the coupling methodology (IEA, 2012).

2. The trade balance is calculated as the value of all exports minus the value of all imports. A positive balance implies that the country receives more value than it pays to entities in other countries.

Figure 15.4 ▷ Demand for goods and services in selected sectors in China in the New Policies Scenario



Household demand grows fastest, though all segments of final demand increase

Notes: Spending refers to final consumption of goods and services. Investment includes corporate spending for non-final capital goods (factories, equipment, etc.). Trade is also a component of GDP, but is excluded from this figure.

Table 15.1 ▷ Major socio-economic trends in China and in developed countries in the New Policies Scenario

	China				Developed countries			
	2000	2016	2025	2040	2000	2016	2025	2040
Annual average GDP growth*	-	9.2%	5.8%	3.7%	-	1.7%	1.9%	1.8%
GDP per capita ($1 000)	4.2	15.7	25.4	44.5	35.3	41.9	47.7	59.5
Investment (share of GDP)	34%	45%	40%	32%	24%	21%	21%	21%
Services (share of GDP)	47%	52%	57%	64%	72%	75%	75%	77%
Employment rate	77%	71%	69%	65%	61%	62%	63%	62%
Labour productivity growth*	-	7.8%	4.4%	3.1%	-	1.3%	1.1%	1.1%
Share of population aged 65+	3%	4%	6%	14%	7%	10%	12%	16%
Mean # years of schooling	7.8	8.6	9.4	10.9	10.6	11.8	12.1	12.4

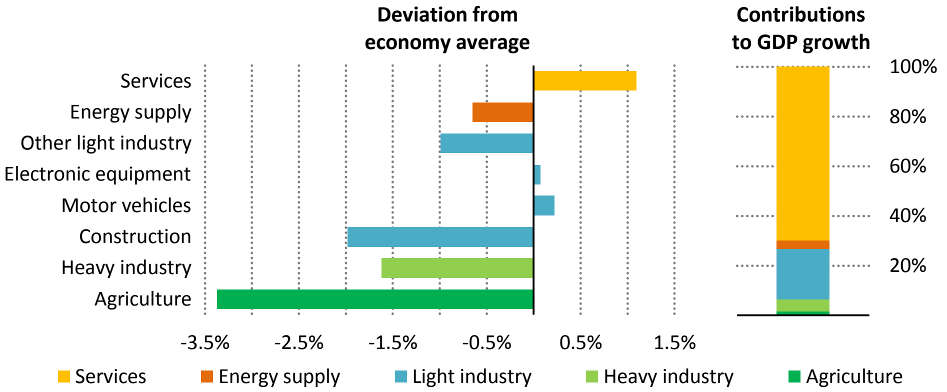
* Annual average GDP growth and average labour productivity growth are for the 2000-2016, 2016-2025 and 2025-2040 periods. Notes: GDP per capita is expressed in thousands of year-2016 US dollars in PPP terms, and the services share of GDP is expressed in constant terms of year-2016 US dollars. Employment rate is expressed as a share of working age population (aged 15-74). The term "developed countries" here refers to OECD countries.

Sources: IEA analysis; OECD/ENV-Linkages Model; OECD Economics Department projections.

These socio-economic trends drive changes in the sectoral composition of the economy in the New Policies Scenario (Table 15.1). Changes are also shaped by government objectives, including a target under the 13th Five-Year Plan to increase the contribution of the services sector; and the "Made in China 2025" initiative, which puts a strong focus on accelerating advanced technologies in key sectors such as high value-added equipment, biotechnology or advanced materials, emphasising green and innovative advanced industrial design (see Chapter 13).

In the New Policies Scenario, the broader socio-economic trends and government policies to support the macroeconomic transition mean that the share of the services sector in GDP gradually gets closer to the level of developed countries: this share reaches 60% by the early 2030s, which is comparable to Korea today, and the services sector contributes 70% of the total increase in GDP through to 2040 (Figure 15.5). China's policy focus on light industries (in particular in the motor vehicles, electronic equipment, and other manufacturing branches) also increases their weight in the economy: they make up 20% of total GDP growth through to 2040 and are the second-largest contributor to GDP growth after the services sector. The power generation sector also gains importance, underlining the importance of electricity in the economic transition (see Chapter 13), but the overall contribution of energy supply to economic growth is small and declines in importance. The contribution of heavy industries and agriculture to overall GDP also shrinks in importance, while still growing in value.

Figure 15.5 ▷ Sectoral value-added contributions to overall economic growth in China, New Policies Scenario, 2016-2040



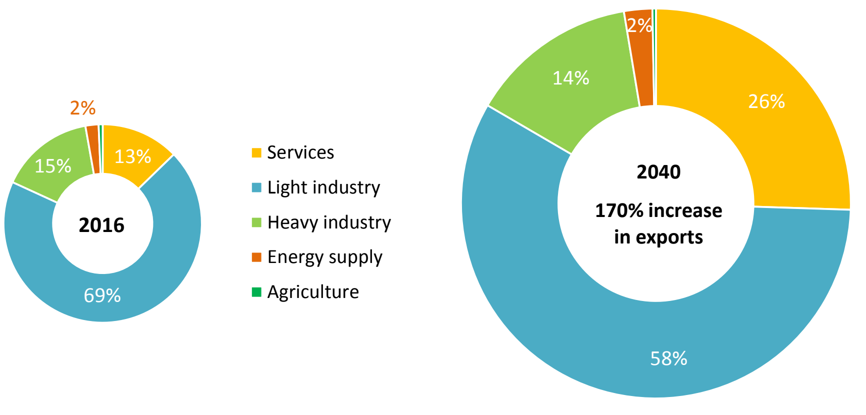
The services sector grows faster than all other sectors, and gains in share of total value added, while energy-intensive industry and agriculture grow more slowly

Notes: The growth rates for the left graph are for sectoral value added, compared to the economy average (4.8% growth by 2040). The right graph represents sectors' contribution to the China's GDP growth over the period to 2040.

Source: OECD/ENV-Linkages Model.

China's efforts to restructure its economic growth model change its role in the world economy. Traditionally, China has been an exporter of low-value manufactured goods, benefiting from its domestic labour cost advantage, affordable energy (especially coal) and attractive environment for foreign investment (which often benefits export-oriented sectors). In the New Policies Scenario, its comparative advantage in some key sectors decreases as wages rise. The shift to services, which are more labour-intensive than manufacturing, decreases the overall growth in labour productivity. Nonetheless, labour productivity is projected to increase more rapidly over time than in more advanced economies. Starting from a relatively lower level, compared with advanced economies, labour productivity in the services sector quickly improves by means of investment in new equipment and digitalisation, education, training and healthcare. In the second wave of industrial development, outlined in the 13th Five-Year Plan, new high-tech export-oriented industries develop in the coastal regions, aided by access to foreign capital, pre-existing export infrastructure, and a skilled labour force, and the Belt and Road Initiative helps to create new markets for Chinese industry.

Figure 15.6 ▷ Share of exports by sector in total Chinese exports in the New Policies Scenario



The services sector's share of exports doubles by 2040

Note: Shares calculated using exports in nominal terms.

Source: ENV-Linkages model.

As it moves towards higher value industry, China aims to develop an internationally competitive automotive manufacturing sector, and in particular to increase production of new energy vehicles (NEVs).[3] China currently produces more vehicles than any other country: at present, nearly all of them are sold in China, with only about 3% exported (compared with 77% in Germany and 62% in Korea). China also aims to develop its strengths in new energy technologies, in line with the "Made in China 2025" initiative. It is already an important supplier of technologically advanced products such as solar panels and wind

3. NEVs include battery electric vehicles, plug-in hybrids and fuel cell vehicles, both for passenger and commercial applications.

turbines to global markets. In the New Policies Scenario, China remains a key exporter of such products, and expands into new export markets, including for nuclear equipment. Overall, China continues to move up the value chain and to create higher value products both for domestic consumption and for export.

The shifts in China's industrial structure and consumption patterns shape the evolution of energy demand and supply in the New Policies Scenario (see Chapters 13 and 14). For example, the shift away from energy-intensive heavy industry, such as iron and steel and cement, drives the projected decrease of coal consumption in industry, while the increasing role of the services sector contributes to the projected rise in electricity demand. As incomes grow, the fuel mix is set to evolve, reflecting changes in the economy and in people's preferences.

15.3.2 Implications of a slower economic transition

The structural changes in the economy outlined in the previous section (and considered in the New Policies Scenario) are far from certain for a variety of reasons. They require changes in policies, production processes and lifestyles: such changes entail adjustments that may be expensive in the short term and difficult to manage, as people move jobs or require additional education or training. They also imply the development of infrastructure and capacity for new or growing industries, the costs of which are uncertain. More broadly, such structural changes could have asymmetrical effects, with both short-term benefits and short-term costs being greater for some people and some areas than for others. There is inevitably a risk of structural changes proceeding more slowly than expected and delaying China's planned economic transition.

In this section, we use the Current Policies Scenario to illustrate the implications of a slower economic transition. This scenario differs from the New Policies Scenario in two main aspects. First, it assumes slower progress in the implementation of the energy, climate and air pollution policies that stimulate the energy transition in the New Policies Scenario.[4] Second, it assumes slower progress in the transition towards a services-oriented economic growth model than in the New Policies Scenario: the share of services in total GDP rises to 60% only by around 2040, which is ten years later than in the New Policies Scenario. Overall, the Current Policies Scenario achieves the same level of economic growth as the New Policies Scenario over the projection period: in both cases the economy grows at an average of about 4.5% a year between 2016 and 2040, GDP nearly triples by 2040, and the overall size of the economy reached in 2040 is similar. But the drivers of growth are different between the scenarios, and this has major implications for the structure and shape of the economy in 2040, and for its energy sector (Table 15.2).

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4. See Chapter 13 for a description of the policies considered in the New Policies Scenario and Annex B for details on the policies in both scenarios.

Table 15.2 ▷ Changes in GDP by driver in China in the Current Policies Scenario relative to the New Policies Scenario

Individual effects	2025	2040
Smaller contribution of services to production	-0.3%	-1.4%
Slower shift from heavy to light industry	-0.1%	-0.1%
Slower shift in household and government spending patterns	0.3%	2.3%
Slower energy transition (excluding air pollution)	0.4%	0.8%
Air pollution damages	-0.1%	-0.2%

Notes: This table shows results of sensitivity analyses, in which each effect is isolated and added to the New Policies Scenario. The numbers correspond to the variation in GDP, where positive numbers represent additional gains in the Current Policies Scenario and negative numbers represent additional costs in the Current Policies Scenario.

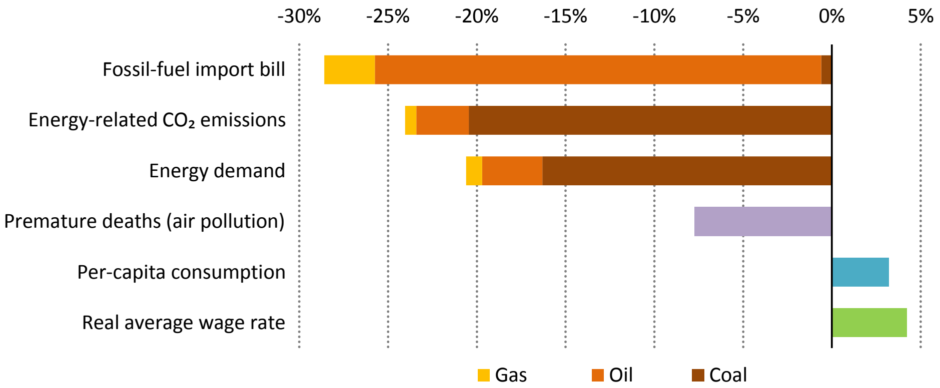
Sources: OECD/ENV-Linkages Model; World Energy Model.

A comparison of the main drivers of GDP by scenario reveals the various factors that impede or spur economic growth in the Current Policies Scenario relative to the New Policies Scenario. For example, the smaller contribution of services to production in the Current Policies Scenario has a negative impact on GDP. In the New Policies Scenario, the intensification of the use of services in production is the result of increased research and development efficiency and gradual improvements of information technology and communications (ITC), among other factors. The relative absence of this effect in the Current Policies Scenario lowers GDP; productivity growth is slower in the manufacturing sector than in the services sector, because productivity levels reached in the manufacturing sector already are closer to the levels of developed countries. In a similar way, the slower shift from heavy to light industries in the Current Policies Scenario also has a small negative impact on GDP. On the other hand, the slower convergence in standards of living towards the levels of developed countries in the Current Policies Scenario implies a lower share of expenditures related to services in household and government budgets. This has an upward effect on GDP in the Current Policies Scenario, since on average service activities are less productive than manufacturing, which offsets some of the losses due to other factors.

The energy transition is also slower in the Current Policies Scenario than in the New Policies Scenario. The lack of implementation of the more stringent climate and energy policies of the New Policies Scenario, including carbon pricing and energy efficiency measures, leads to small GDP gains, relative to the New Policies Scenario, as it frees up resources that can be allocated elsewhere in the economy. The slower energy transition means however a greater reliance on fossil fuels than in the New Policies Scenario, which leads to higher levels of concentration of air pollutants and affects labour force quality and productivity, increasing private and public health expenditures by 2.5%, and decreasing GDP in the Current Policies Scenario, relative to the New Policies Scenario.

While important, a focus on GDP alone is not sufficient to assess the differences in outcomes between the macroeconomic and energy transitions that are depicted in the Current and New Policies Scenarios. For example, from a standard of living aspect, households may be better off in the New Policies Scenario than in the Current Policies Scenario because they benefit from more services, even if overall GDP is the same. A focus on 2040 may also be shortsighted. Although the economic growth pathway in the Current Policies Scenario does not negatively affect GDP through to 2040, it is likely that a more energy- and CO_2-intensive economy would be less well-equipped to sustain long-term growth beyond 2040.

Figure 15.7 ▷ Foregone benefits due to a slower economic and energy transition in China in the Current Policies Scenario relative to the New Policies Scenario, 2040



Foregone benefits of a slower economic and energy transition have important ramifications beyond GDP

Sources: OECD/ENV-Linkages model; IEA; International Institute for Applied Systems Analysis (IIASA).

It is therefore also important to assess the foregone benefits that a macroeconomic and energy growth pathway as in the Current Policies Scenario would entail (Figure 15.7). From an energy perspective, the main benefits of the New Policies Scenario, relative to the Current Policies Scenario, are related to more improvements in energy efficiency and lower CO_2 emissions, which strengthen energy security and reduce economic vulnerability. In the New Policies Scenario, import bills for oil and gas are respectively \$230 billion and almost \$30 billion lower in 2040 than in the Current Policies Scenario; energy demand is more than 600 Mtoe lower; fine particulate matter ($PM_{2.5}$) emissions are 550 kilotonnes (kt) lower and nitrogen oxides (NO_X) emissions are 2 Mt lower, reducing associated premature deaths; and CO_2 emissions from fuel combustion are reduced by 2.7 Gt CO_2, of which 85% is from less coal combustion. By 2040, oil imports are 2.2 mb/d lower in the New Policies Scenario than in the Current Policies Scenario, a difference that corresponds to roughly 80% of China's total oil consumption in the industry sector in 2016.

From a socio-economic perspective, workers shift to higher value-added sectors in the New Policies Scenario: although the net impact on total employment rate is low, wages are higher than in the Current Policies Scenario. The increase in real wages of 4% in 2040 translates into an increase in real consumption in households of around $1 270 per capita.

15.3.3 Conclusions

The macroeconomic transition is an important uncertainty in our projections of China's energy demand. Yet, our analysis suggests that China has important reasons to push ahead with its transition. Although delay in doing so would not lead to material differences in the outlook for overall GDP growth through 2040, the potentially foregone benefits for China in terms of health and well-being are likely to be important motivations for policy-makers to continue on the transition path. Nonetheless, it is important to recognise that such wide macroeconomic shifts are not easy to accomplish – there may be roadblocks and detours on the road ahead. The pace of the transition will be closely watched by the energy world: a delay by ten years could increase China's energy demand in 2040 by more than 600 Mtoe (or 15%), the equivalent of Southeast Asia's entire current energy demand, with implications for international energy prices as well as for energy-related CO_2 emissions.

15.4 What if the clean energy transition is faster?

The scale and speed of China's rise as an economic power has led to a significant rise in CO_2 emissions and to local environmental degradation, particularly air pollution. The air pollution problem is particularly severe: China's leaders declared a "war against pollution" and referred to smog as "nature's red-light warning against inefficient and blind development". Increasingly, a clean energy transition is seen as a necessity and is amply reflected in China's 13th Five-Year Plan, with its targets to reduce carbon and air pollutant emissions. In addition, three important steps have been taken in recent years: ratification of the Paris Agreement in 2016; revision of the National Air Quality Standard in 2012 and subsequent publishing of a real time air quality index in 74 cities (expanded to 367 cities in 2015); and release of the Action Plan on Prevention and Control of Air Pollution in 2013, with the objective of strictly controlling coal consumption and tightening air pollution guidelines in key industrial areas.

In the New Policies Scenario, which takes account of these policies and targets, China achieves a peak in energy-related CO_2 emissions just before 2030. Over the *Outlook* period, sulfur dioxide (SO_2) emissions fall by around 40%, while NO_X and $PM_{2.5}$ emissions fall by nearly 50%. Despite this progress, 1.4 million people still die prematurely from outdoor air pollution in 2040 in the New Policies Scenario, compared with less than 1 million today, as a result of the continuing ageing and urbanisation of China's population.

Against this background, it is conceivable that China will not settle for its current level of ambition for a clean energy transition. The country's high-level policy targets and the call for an "energy revolution" by China's president already reflect a high long-term level of ambition. This section explores what a more rapid clean energy transition might look like, drawing on the Sustainable Development Scenario (see Chapter 3).

15.4.1 A possible pathway to a cleaner energy sector

Emissions trends in the Sustainable Development Scenario

An energy sector transition in line with climate as well as air quality goals requires more profound changes in the energy mix than those in the New Policies Scenario. The Sustainable Development Scenario depicts such a pathway. In the case of China, it assumes strong carbon price incentives in the power, industry and aviation sectors, building on the emissions trading system scheduled to be implemented nation-wide by the end of 2017; ambitious minimum energy performance standards that extend and enhance current policy efforts across all end-use sectors (Table 15.3), together with wider application of Green Buildings Standards; continued support for the deployment of low-carbon technologies, including for renewables, carbon capture and storage (CCS) and nuclear in the power sector, electric cars in transport, the use of solar thermal heat in industrial and residential applications; and the tightening of existing air pollutant emissions standards across all sectors, plus enhanced monitoring and enforcement.

Table 15.3 ▷ Performance levels for selected products by sector in China in the Sustainable Development Scenario

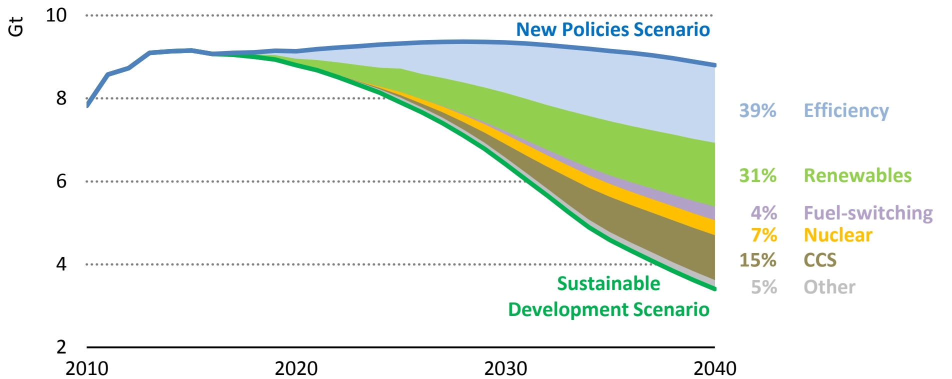
Sector	Type	Performance level	
		Today	Sustainable Development Scenario in 2040
Industry	Electric motors	Sales of industrial electric motors meet IE3 ("premium") standard from 2016 onward.[5] (Less than 15% of the total existing stock is at IE3 level or above.)	More than 95% of sales reach at least IE4 ("super premium") level. More than 80% of the stock is at IE4 level or above in that year.
Transport	Cars	Today: 6.9 l/100 km. Fuel-economy standards target 5 l/100 km in 2020, and strive to achieve 4 l/100 km in 2025.	Below 3 l/100 km.
	Trucks	Fuel economy index: 100.	Medium trucks: 50. Heavy-duty trucks: 60.
Buildings	Refrigerators	380 kWh/year.	340 kWh/year.
	Cleaning equipment	220 kWh/year.	250 kWh/year.
	Lighting	1.4 kWh/m².	0.9 kWh/m².
	Heating and cooling	New residential building energy consumption per floor space index: 100.	50.

Notes: l/100 km = litres per 100 kilometres; kWh = kilowatt-hour. Cleaning equipment refers to washing machines, dryers and dishwashers. For such appliances, the average consumption in 2040 does not decrease significantly compared with today as the size of equipment rises with higher income per dwelling.

5. On the basis of the definition of the International Electrotechnical Commission.

Implementation of the policies assumed in the Sustainable Development Scenario leads to a fundamentally different energy and environmental outlook in China. Energy-related CO_2 emissions continue their recent decline, falling back to 2001 levels by 2040, despite a GDP that is eleven-times larger (Figure 15.8). The largest contributions to emissions savings, relative to the New Policies Scenario, come from energy efficiency improvements and renewables. CCS plays an important role in minimising the risk of stranded assets in China's young coal-fired power fleet and industrial processes. The majority of the cumulative savings occur in the power sector, which is by far the largest source of CO_2 emissions today, although not all of the savings in this sector are directly attributable to power sector decarbonisation: 17% of the total savings are realised by energy efficiency measures to moderate electricity demand growth. By 2040, the CO_2 emissions intensity of electricity generation is around 60 grammes per kilowatt-hour (g/kWh), down from 650 g/kWh today, and this brings about a cut in power sector emissions to 20% of today's level, despite a 50% increase in output. Overall, the CO_2 emissions intensity of economic output (measured in CO_2 emissions per unit of GDP) falls by 8.2% per year on average, nearly twice the rate of the New Policies Scenario. CO_2 emissions per capita fall to the level of the mid-1990s by 2040.

Figure 15.8 ▷ China CO_2 emissions in the Sustainable Development and New Policies Scenarios

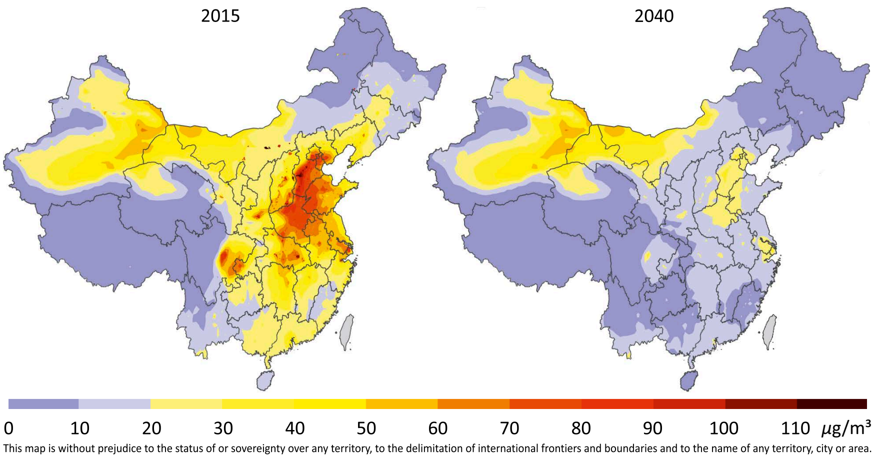


Energy efficiency and renewables are China's key mitigation options

Note: Percentages shown are cumulative emissions savings by measure to 2040.

Emissions of air pollutants decline steeply in the New Policies Scenario, driven by the existing stringent targets for different parts of the energy sector. However, air pollution in some industrial areas still exceeds the Chinese National Air Quality Standard (Chapter 13). The Sustainable Development Scenario provides considerable further improvements to air quality in China. By 2040, nearly all the population live in areas where air quality is compatible with the National Air Quality Standard, up from 36% today (Figure 15.9). The result is a dramatic health improvement for China's population. By 2040, there are nearly 0.5 million fewer people who die prematurely from the impacts of outdoor air pollution than in the New Policies Scenario, stabilising the health impact of air pollution at just below today's level despite an ageing and urbanising population. Meanwhile the impact of indoor household air pollution is reduced by three-quarters as the use of polluting fuels for cooking in rural areas declines.

Figure 15.9 ▷ Concentration of $PM_{2.5}$ in China in the Sustainable Development Scenario



Air quality significantly improves in the Sustainable Development Scenario

Source: IIASA.

The reason for these improvements is that, in the Sustainable Development Scenario, emissions of all major pollutants drop well below the level of the New Policies Scenario. By 2040, $PM_{2.5}$ and SO_2 emissions are two-thirds below the level in the New Policies Scenario, and NO_X emissions are 50% below. The majority of the additional emissions reductions across pollutants come from the industry and transformation sectors. Although there is no shortage of emissions regulation from these sectors, there are more than 70 million scattered small- and medium-size enterprises in the country, making enforcement challenging. Overcoming these hurdles (primarily in the quest to reduce process-related emissions) and reducing energy demand from these sectors explain the decline in $PM_{2.5}$ and SO_2. The power sector is another important contributor to reductions in air pollutant emissions: SO_2 and NO_X emissions are around 75% and $PM_{2.5}$ emissions more than 80% below the level of the New Policies Scenario in 2040, driven by a move to low-emissions technologies. In transport, SO_2 emissions are 85%, NO_X levels 35% and $PM_{2.5}$ levels 25% below the level of the New Policies Scenario in 2040, with the decline in $PM_{2.5}$ emissions reduced by the continued increase in distance driven by cars and trucks (one-third of the remaining transport-related $PM_{2.5}$ emissions in 2040 come from abrasion, brakes and tyres). In the buildings sector, NO_X emissions decline by 60% below the level of the New Policies Scenario in 2040, and SO_2 emissions by 75%. The decline in $PM_{2.5}$ emissions (85%) is among the largest across sectors: the principal contribution comes from a decline in emissions from cooking in rural areas.

Energy trends in the Sustainable Development Scenario

The evolution of China's energy sector in the Sustainable Development Scenario does not show a fundamental break either from current trends or from those in the New Policies Scenario. Rather, it shows enhanced efforts in the same direction in order to bring about a faster and more complete transformation. In the Sustainable Development Scenario, the energy intensity of economic output (measured in energy use per unit of GDP) declines by 4.3% on average per year through to 2040 (Table 15.4) and total energy demand peaks by the late 2020s. Coal demand falls by 3.5% a year, a decline twice as fast as the one seen over the past two years: it drops to 1 200 Mtce in 2040, half the level reached in the New Policies Scenario, as the decline in coal-fired power generation accelerates the overall fall in coal demand from iron and steel (see Chapter 13). Oil demand peaks by the mid-2020s: at just below 11 mb/d in 2040, it drops back to the level of 2014, 5 mb/d below the level in the New Policies Scenario. Natural gas is the only fossil fuel that registers an increase over the level of the New Policies Scenario, driven by the power sector and increased use in road freight transport in trucks: at 660 bcm in 2040, natural gas demand is more than three-times higher than today, and around 50 bcm higher than the level reached in the New Policies Scenario (see Chapter 11).

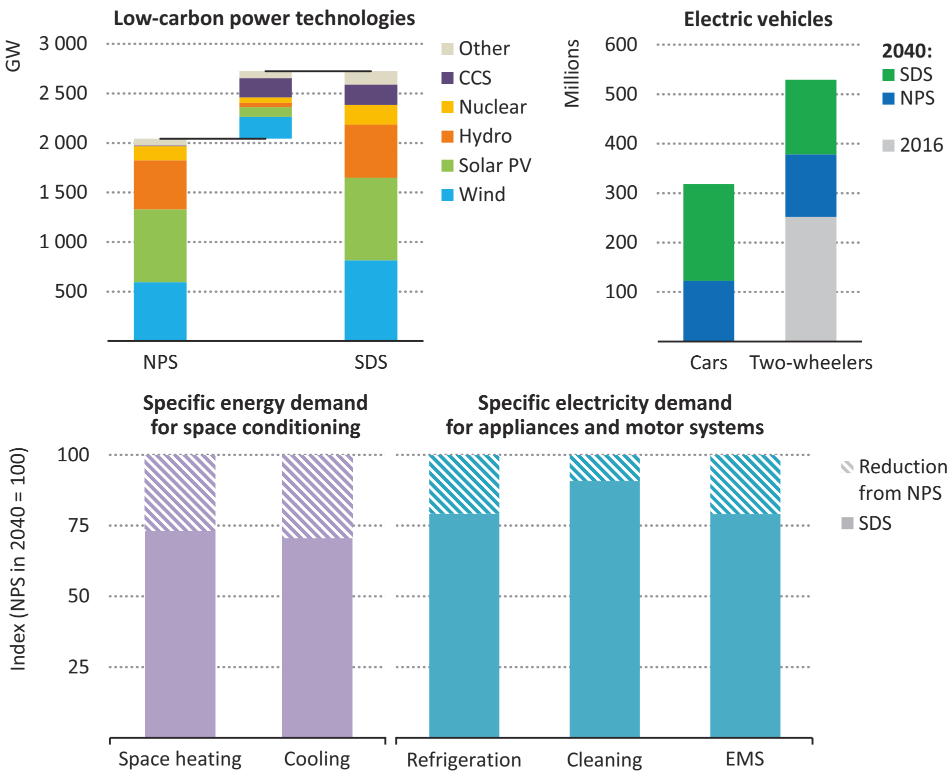
Table 15.4 ▷ China primary energy demand by fuel in the Sustainable Development Scenario (Mtoe)

	2016	2020	2025	2030	2035	2040	Change from NPS, 2040	CAAGR* 2016-2040
Coal	1 957	1 859	1 599	1 305	1 041	833	-51%	-3.5%
Oil	552	602	633	606	540	482	-33%	0.0%
Gas	172	233	311	395	468	516	10%	-1.6%
Nuclear	56	102	189	288	353	395	38%	0.6%
Renewables	269	315	415	548	681	794	28%	0.3%
Hydro	102	107	114	125	134	140	8%	0.1%
Bioenergy**	112	102	114	151	188	218	14%	1.8%
Other renewables	55	106	186	273	360	436	47%	2.0%
*Fossil-fuel share****	*89%*	*87%*	*81%*	*73%*	*66%*	*61%*		
*Fossil-fuel share*****	*87%*	*83%*	*76%*	*69%*	*62%*	*56%*		
Total	**3 006**	**3 110**	**3 146**	**3 142**	**3 083**	**3 021**	**-20%**	**0.0%**

* Compound average annual growth rate. ** Includes the traditional use of solid biomass and modern use of bioenergy. *** Calculated using IEA methodology. **** Calculated using methodology of China's National Bureau of Statistics to aid comparability with China's published targets. Note: NPS = New Policies Scenario.

In the Sustainable Development Scenario, all low-carbon technologies grow strongly. In the power sector, the share of low-carbon generation rises to 90% in 2040 (from just above 50% in the New Policies Scenario), of which two-thirds is from renewables, almost 20% from nuclear and the remainder from CCS. Among the more established technologies, solar photovoltaic (PV) and wind generation experience the largest growth rates. The 2030 targets of the Energy Production and Consumption Revolution Strategy (2016-30) are met, supported by efforts to reform the power market (see Chapter 13). By 2040, 35% of total electricity generation is from solar PV and wind alone, with an installed capacity of almost 1 700 GW. Nuclear also expands its role, with an additional capacity of 55 GW in 2040, relative to the New Policies Scenario. Natural gas becomes an increasingly important source of flexible power generation, its share in generation rising to 10% in 2040, two percentage points above the level of the New Policies Scenario. Coal capacity drops sharply, as around 500 GW is retired over the projection period. Much of the remaining coal-fired generation comes from plants that are retrofitted with CCS; in 2040, only around 20% of coal-fired power generation is unabated. Coal and gas capacity with CCS rises to 200 GW.

Figure 15.10 ▷ Key indicators of China's low-carbon transition in the Sustainable Development Scenario



The Sustainable Development Scenario needs more low-carbon deployment across all sectors

Note: NPS = New Policies Scenario; SDS = Sustainable Development Scenario; EMS = electric motor systems.

Changes in the transport sector provide the main reason for China's oil demand peak in the Sustainable Development Scenario. First, the stock of electric cars rises to around 320 million vehicles in 2040, making up around 60% of China's passenger car stock and more than one-third of the global stock of electric cars. By 2040, 20% of road transport fuel use is electricity, amounting to almost 800 terawatt-hours (TWh). Second, in road freight transport, the efficiency of the truck fleet increases and the use of alternative fuels rises. In 2040, 30% of all fuel use for long-haul trucks is from natural gas or biodiesel.

Despite the strong electrification of transport, China's overall electricity demand rises by only 1.8% per year on average through 2040 in the Sustainable Development Scenario, compared with 2.3% in the New Policies Scenario. This is still a 55% increase over today's level, while total primary energy demand stays broadly flat, which highlights the key role of electricity in supplying future energy services. The main reason for the lower electricity demand growth in the Sustainable Development Scenario, relative to the New Policies Scenario, is the more rapid increase in energy efficiency, which constitutes a central pillar of the low-carbon transition in the industry and buildings sectors. In the industry sector, electricity use reaches that of coal to become the leading source of energy demand by 2040. Its overall average growth rate of 1.1% per year, however, is significantly lower than the 1.8% per year projected in the New Policies Scenario as a result of the effects of the minimum energy performance standards for industrial motors and other energy efficiency measures. The use of coal in industry falls to 30% below the level of the New Policies Scenario in 2040, with the share of coal in industrial energy use dropping to less than 30%, around half the level of today.

In the buildings sector, electricity demand also grows less than in the New Policies Scenario due to the efforts to increase the energy efficiency of appliances and lower energy demand for cooling in particular. The use of district heat and natural gas is also lower as energy used in space heating drops from improving building codes by 12%, relative to today, 27% below the level in the New Policies Scenario.

Box 15.1 ▷ Looking ahead to 2050: establishing China's 2050 strategy

China is in the middle of preparing its mid-century decarbonisation strategy in preparation for the international facilitative dialogue under the Paris Agreement. The mid-century date of the strategy coincides with that of China's Centenary Goal for 2049, 100 years after the founding of the People's Republic.

Since 1978, China has successfully achieved the first stage of building a "moderately prosperous society" by the beginning of this century. A key goal of China's modernisation process is now to accomplish the first Centenary Goal of building a moderately prosperous society in all respects, with a focus on improving the livelihood of people and doubling by 2021 the level of GDP achieved in 2010. China's leaders have also called for the construction of an "ecological civilisation" with "blue sky and green water" as a part of the "China dream". An accelerated low-carbon transition like the one in the

Sustainable Development Scenario would help bring about the achievement of the Centenary Goal by helping with the construction of an "ecological civilisation", driving innovation breakthroughs and green growth opportunities, and improving social welfare. Continued efforts along the path of the Sustainable Development Scenario after 2040 would bring down China's CO_2 emissions further to below 2.5 Gt by the anniversary year of 2049, reducing per-capita emissions to a level last seen during the late 1980s.

15.4.2 China's investment needs in the Sustainable Development Scenario

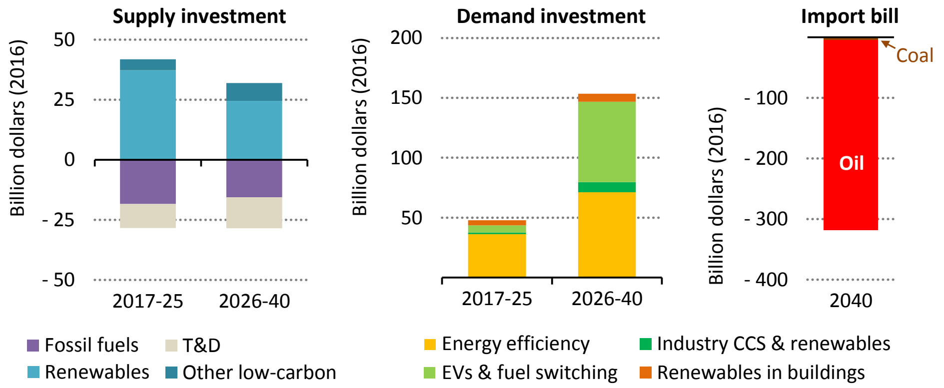
China is the country that invests the most in the energy sector already today, including for low-carbon technologies and energy efficiency. In the New Policies Scenario, through 2040, China invests $6.4 trillion in energy supply (of which $4.5 trillion is in the power sector), and around $3.6 trillion is in end-use sectors (see Chapter 14). Much of this investment is for low-carbon technologies and energy efficiency: at $5.9 trillion, more than half of the total investment is to support the deployment of such technologies, and an additional $1.9 trillion is investment in power transmission and distribution (T&D) networks.

Investment needs in the Sustainable Development Scenario go well beyond those levels (Figure 15.11). At $12.9 trillion, total energy investment through to 2040 is almost one-third higher than in the New Policies Scenario. There are distinct variations by sector. Investments in energy supply increase by only 3% to $6.6 trillion through to 2040, as rising power sector investment needs are partly offset by lower investment in fossil fuels, notably oil. In the power sector, investment in low-carbon technologies rises by 45% to $3.4 trillion, the majority of which is for renewables (80%), followed by nuclear (13%) and CCS (7%). Investment needs in power generation are partly moderated by a 15% decline in T&D investments, as total electricity demand is 11% lower than in the New Policies Scenario.

The majority of the additional cumulative investment in the Sustainable Development Scenario is required for the decarbonisation of end-use sectors, which rises by almost 80% over the level of the New Policies Scenario to $6.3 trillion. Half of the additional investment is for energy efficiency, in particular in the buildings sector to improve the efficiency of appliances, cooling technologies and insulation levels. The other half of the additional investment is for the use of low-carbon fuels in end-use sectors: the majority of this is for electric cars, which absorb an additional $1 trillion through to 2040 above the level of the New Policies Scenario. The remainder is for the use of renewables in buildings, and CCS and renewables in industry.

The additional investment requirements are partially compensated by offsetting savings elsewhere. Fossil-fuel import bills decline substantially in the Sustainable Development Scenario as demand declines, in particular for oil. Net imports of oil in 2040 are 9.1 mb/d, 3.9 mb/d below the level of the New Policies Scenario. In the Sustainable Development Scenario, spending on total fossil-fuel imports through to 2040 is $3.5 trillion lower than in the New Policies Scenario, meaning that each additional $1 invested in low-carbon technologies and energy efficiency saves $1 on fossil-fuel imports over the *Outlook* period.

Figure 15.11 ▷ Additional average annual investment needs and change in fossil-fuel import bills in China in the Sustainable Development Scenario relative to the New Policies Scenario



Investment in energy supply is re-directed to low-carbon power generation, while demand-side investment rises strongly and fossil-fuel import bills fall

Note: T&D = transmission and distribution; EV = electric vehicles; CCS = carbon capture and storage.

15.4.3 Conclusions

The desire to steer the energy sector transition towards a more efficient and cleaner use of energy is an increasingly important guiding principle for many aspects of China's energy policy-making. The Sustainable Development Scenario provides an insight into the likely results and benefits from undertaking the kind of accelerated transition consistent with a high level of future ambition. The investment requirements are significant, but the combined environmental and energy security benefits are also significant. Depending on how progress towards implementation of the revolution strategy plays out over the next few years, China's energy outlook might develop in ways that become increasingly well aligned with the Sustainable Development Scenario.

15.5 Global implications of China's energy development

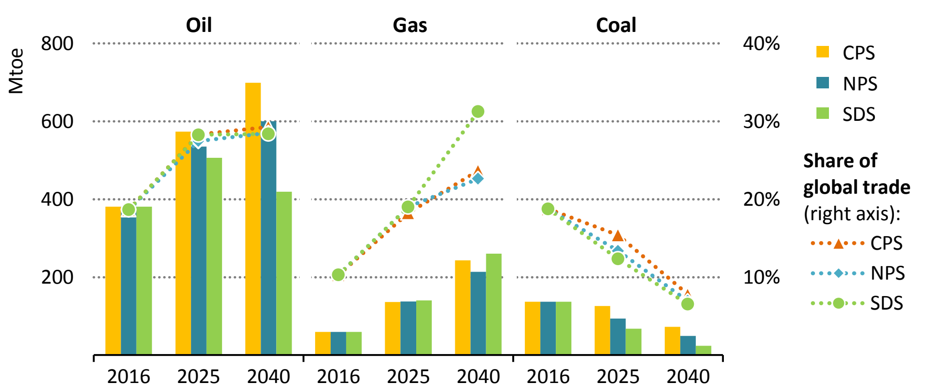
China's influence in global energy affairs spans all fuels and technologies, and the energy pathway that it follows will therefore have profound implications for global markets, trade and investment flows, and technology costs. China's policies give a clear indication of the future direction of travel and this is reflected in the New Policies Scenario. The outlook for China's energy sector, however, is not set in stone; we have explored two key areas of uncertainty in the previous sections and, in this concluding discussion, we examine the implications of different pathways and choices for global energy markets.

15.5.1 Oil, gas and coal markets

Recent years have seen major changes in China's interactions with oil, gas and coal markets. Changes in China's coal import needs in 2013 left global markets heavily over-supplied and sent prices down before China's more recent attempts to rein in domestic overcapacity spurred a price recovery. Concerns about high oil and gas import bills have eased with the fall in prices since late 2014, which has opened some new opportunities and risks. The opportunities relate mainly to natural gas: a period of ample supply creates a propitious moment for domestic market reforms, which would help the longer term prospects for gas in China. The risks relate mainly to oil: lower prices at the current level might stall the momentum behind promoting alternatives to oil in the transport sector.

Over the long term, our projections in all scenarios show a steady increase in the import requirement for oil to 2025 as demand increases across sectors. After 2025, oil import requirements take different directions across the scenarios, depending on policy paths. While import requirements continue to increase in the Current and New Policies Scenarios (the level varying with underlying assumptions on policy and its implementation), the trend reverses in the Sustainable Development Scenario in the face of concerted and determined action on fuel efficiency and fuel mix diversification, which leads to a very rapid rise in the number of electric cars (Figure 15.12). The requirement for natural gas imports continues to rise across all three scenarios, reflecting the role that this fuel continues to play in China's efforts to diversify the energy mix and to address environmental challenges. China retains a substantial, but steadily declining, need for imported coal in each scenario.

Figure 15.12 ▷ China's net energy imports and share of global trade by scenario



China's shares of global oil and gas trade rise in each scenario, while its role in global coal trade is projected to diminish

Note: CPS = Current Policies Scenario; NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

Our projected imports follow smooth trajectories, but this should not mask the possibility, even the likelihood, of substantial volatility in both international prices and import levels – a factor that could have a substantial impact on China's policy preferences, but could also to some extent be caused by those preferences, or by changes in them.

Oil markets

In the New Policies Scenario, China's net oil imports rise from 8 mb/d today to 13 mb/d in 2040 (over 80% of total demand), with crude oil accounting for the majority of imports (11.3 mb/d in 2040). China is already the world's largest net importer of oil: the volumes projected for 2040 approach the largest amount ever imported by a single country (the record was set by the United States in 2005) and mean that, of every ten barrels of internationally traded oil in 2040, almost three barrels will be heading to China. Dependence on imports on this scale raises two questions. First, how might China seek to mitigate the risks arising from such import dependence? Second, how might further policy action by China on the demand side affect the picture?

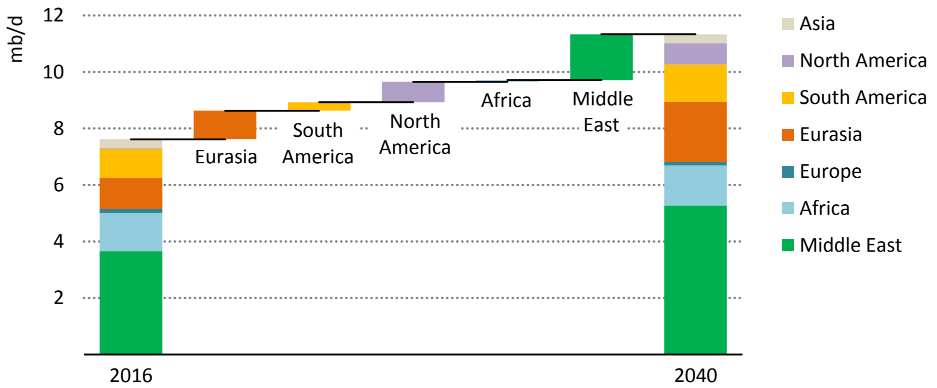
One way of reducing the risks of dependence on oil imports is through the diversification of sources of supply, and there are some encouraging signs here for China: non-traditional oil exporters are emerging and refiners are enhancing their ability to take a wide range of crude grades. The most promising of these over the longer term are pipeline imports from Russia and Kazakhstan, and seaborne imports from North America, notably Canada. In our projections, Russia (through a planned expansion of the Eastern Siberia-Pacific Ocean pipeline to 1.6 mb/d) and Kazakhstan (through an extra 360 thousand barrels per day (kb/d) enabled by the reversal of the Kenkiyak-Atyrau segment and planned expansions) together could add around 1 mb/d on top of what they are exporting today, representing around a quarter of China's incremental needs. China has already emerged as the leading buyer of crude exports from the United States (partly because the start of US exports coincided with an increase in purchases by independent refiners in China). However, the long distances[6] and the projected plateau (and subsequent decline) in US tight oil production in the longer term are likely to mean that China looks for additional sources of oil. Canada is well placed to export oil to China, although this is dependent on the construction of additional export capacity to bring inland production to the Pacific coast. If planned pipeline projects come to fruition, the United States and Canada combined could export more than 700 kb/d to China by 2040 (Figure 15.13).

The scope for some other current crude suppliers to expand their trade with China is more limited. China's imports from Latin America have surged in recent years, but the potential for further imports in the longer term is limited by slowing production growth. Africa has diverted an increasing amount of its light crude exports to China in recent years as exports to the United States have fallen back, but the production outlook seems unlikely to support an increase in this contribution. This means that, in our projections, China has little

6. Despite the recent expansion, the Panama Canal is not able to accommodate Very Large Crude Carriers (VLCC), so the bulk of crude oil exports continue to flow through the Atlantic Basin.

alternative but to turn to its existing main suppliers in the Middle East for an additional 1.6 mb/d of supply. This in turn would increase its reliance on trade via the Straits of Hormuz and the Strait of Malacca, two potential strategic chokepoints in global oil trade.

Figure 15.13 ▷ China's crude oil import by origin in the New Policies Scenario



The Middle East remains a crucial source of crude oil import for China to 2040

The New Policies Scenario therefore presents a world in which China and the Middle East enter into a deeper mutual dependence. From China's point of view, as it looks ahead, the Middle East accounts for around half of its crude oil supply in 2040; from the point of view of Middle East suppliers, China is the destination for around a quarter of their exports. In parallel, commercial ties between the two regions are expected to strengthen. Saudi Aramco already holds equity in a refinery in Fujian, and is seeking more business opportunities in China's downstream sector. At the same time, China is looking for stakes in upstream activities in the Middle East: the award of 12% of Abu Dhabi's largest oil concession to Chinese companies earlier in 2017 was a striking example of it taking such a stake. There are also elements of competition between the Middle East and China, notably in oil product markets and in petrochemicals as the Middle East emerges as the world's third-largest refining centre, but this does not alter the point that a mutually beneficial relationship with the Middle East is critically important to China's oil security in the New Policies Scenario.

There are other measures that China could take in order to enhance its security of oil supply. For example, it could take further action to reduce the percentage of its oil coming through the Strait of Malacca (although there are limits to what is likely to be practicable); and it could further develop its oil stocks (although stocks to cover 90 days-worth of projected 2040 imports would be in excess of 1 billion barrels). China could boost domestic oil production (although the scale of required investment extends well beyond historical investment levels of the three major national oil companies let alone technical expertise needed to develop challenging plays). It could take a position to become even more active in efforts to secure upstream positions for Chinese companies in resource-rich countries (although the pace of overseas investment has slowed somewhat in recent years, and some new cross-border pipeline projects have seen delays). As noted in the 13th Five-Year Plan, China could also take a broader system-wide view of the instruments and policies that could safeguard China's oil security.

In this context, one path that could make a fundamental difference would be to further action to reduce oil demand, via more concerted efforts to diversify away from oil and to use it more efficiently, as well as to accelerate the clean energy transition. The New Policies Scenario already envisages a flattening in oil demand for passenger cars by the 2030s stemming from a rise in the number of electric cars, the implementation of ambitious fuel-efficiency targets, and a projected slowdown in the growth of car ownership. Fuel-efficiency standards do not just apply to passenger cars: China is one of only five countries in the world with established fuel-economy standards for trucks. Road freight transport becomes 30% more efficient in the New Policies Scenario than it is today as a result of these standards (and their enforcement) and also as result of improvements in road infrastructures, higher truck capacities and the widespread use of digital technologies. As a result, while oil continues to be central to meeting transport fuel demand in 2040, its share of total fuel use drops to just above three-quarters, from nearly 90% today.

The Sustainable Development Scenario demonstrates how long-term oil demand growth could be further moderated, via additional improvements in fuel efficiency, and three-times as many electric cars on the road as in the New Policies Scenario. In the Sustainable Development Scenario, China's oil demand peaks by the mid-2020s and falls to 10.5 mb/d in 2040, 5 mb/d lower than in the New Policies Scenario, by which time net imports are just over 9 mb/d. (The scenarios also illustrate the potential consequences of failure to move towards a cleaner energy future in the ways outlined in the New Policies Scenario: in the Current Policies Scenario, China's dependence on imported oil rises to a net 15 mb/d by 2040).

The transport sector is the key sector to watch. The amount of oil used for petrochemical feedstocks in 2040 does not differ much between the New Policies and Sustainable Development Scenarios (it is around 3 mb/d in both), but the amount used for transport varies significantly. In the Sustainable Development Scenario, China's transport sector uses about 4.4 mb/d in 2040, which is nearly half the level of the New Policies Scenario. China's electric vehicle ambitions and its desire to tackle urban air pollution mean that it is possible that the future growth of conventional passenger cars will turn out to be lower than projected in the New Policies Scenario: as noted in Chapter 13, this alone could cut up to 2.5 mb/d of gasoline from China's oil import needs in 2040.

Another consideration in oil security terms is the balance between crude and product imports. In our projections, China's refinery runs reach around 14 mb/d by 2040, 30% up from today. Lower refining capacity addition than the level assumed in the New Policies Scenario would heighten product import needs to some extent (a development that could bring its own energy security issues because of reliance on long supply routes for different products). However, it would also bring down the requirement for crude import.

Natural gas markets

The growing gap between projected consumption and China's domestic production means that China's interactions with global gas markets become increasingly close and complex over the period to 2040. By that year, China imports more than any other country, with its total projected import requirement amounting to 280 bcm. By the 2030s, imports account for close to 50% of total consumption, but China builds up a diverse range of suppliers, with the largest sources of imports, Turkmenistan and Russia, each having roughly a 30% share of imports (described in Chapter 14).

The eventual scale of China's participation in global natural gas trade is subject to uncertainties on both the demand and supply sides. On the demand side, as emphasised in Chapter 13, the outlook for gas is contingent on the place that gas finds in China's overall energy strategy. In the New Policies Scenario, China accounts for roughly one-quarter of global gas demand growth to 2040, with the largest demand growth coming from industry (especially lighter industries), power generation, households (especially in eastern provinces) and transport, in that order. There are strong competitive pressures in each of these areas and, if gas is to thrive, it is likely to need support from a range of policies and regulations covering issues such as air quality in smaller industrial facilities, clean cooking and space heating in the residential sector, and fuel diversification for trucks. There is however little variation in demand between the projections for gas demand in the New Policies Scenario and the Sustainable Development Scenario: indeed, China is one of the few countries that actually sees higher gas demand (by around 9%) in the Sustainable Development Scenario than in the New Policies Scenario (India is another).

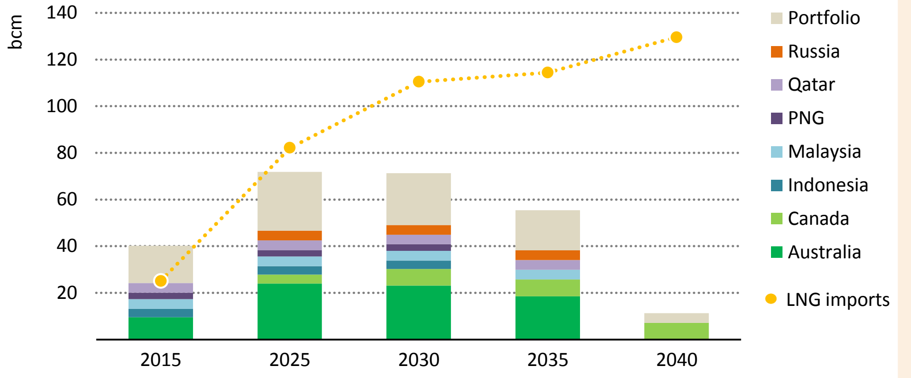
Much larger variations around our main scenario are possible on the supply side, with the outlook for shale gas production at the heart of the uncertainty. Our projected 100 bcm of output from shale by 2040 is perhaps upbeat given current sentiment from operators in the Sichuan Basin (the exception being Sinopec, whose Fuling development is a bright spot), but that has to be weighed against the estimated size of China's resource base. Experience in the United States has shown that, once the right mix of technologies and drilling techniques is found for a particular shale play, then output can rise very rapidly. If this proves to be the case in China then our projections for shale gas supply would need to be revised upwards (Box 15.2).

China's expanded role in international gas trade, combined with the nature of its domestic gas consumption, also makes it a lynchpin of global gas security. As described in Chapter 9, the ability of gas markets to absorb shocks and unexpected disruptions depends on the degree of flexibility in the system, and in particular on the ability of consumers to cut back on gas use if and when prices rise sharply. A well-functioning gas market in China, combined with the possibility of switching if gas prices spike to alternative fuels for power generation (in the first instance, to coal) would provide a valuable source of demand-side flexibility and – because of China's importance in global gas trading – would also benefit other gas importers, particularly if, as projected, the possibilities of switching from gas to coal diminish substantially in other markets such as the European Union and the United States.

Box 15.2 ▷ An upside for China's shale gas would prolong the pain for the global LNG industry

Based on the information available today, it may appear fanciful to suggest that China could move towards self-sufficiency in natural gas. But the United States provides a vivid example of how quickly shale developments can confound expectations and take international markets by surprise. What would be the implications of an extra 200 bcm of shale output in China, over and above our projection? First and foremost, it would help the strategic case for gas in Chinese policy, accelerating its adoption in industrial and other markets, and thereby (to the extent that it replaced coal) bring down emissions of CO_2 and other pollutants. It would also bring down gas imports, with the impact being felt primarily in liquefied natural gas (LNG) markets: pipeline deliveries would be ring-fenced to an extent by long-term supply commitments.

Figure 15.14 ▷ LNG imports and contracted volume by supplier in China in the New Policies Scenario



China remains over-contracted for the next few years but additional import needs from the early 2020s become a major spur for worldwide investment in new LNG supply

Notes: Aggregators, also called portfolio players, are typically international oil and gas companies or large utilities with global operations that, in addition to having their own equity LNG production, have enhanced their supply portfolios by signing up to long-term deliveries from other LNG projects. PNG = Papua New Guinea.

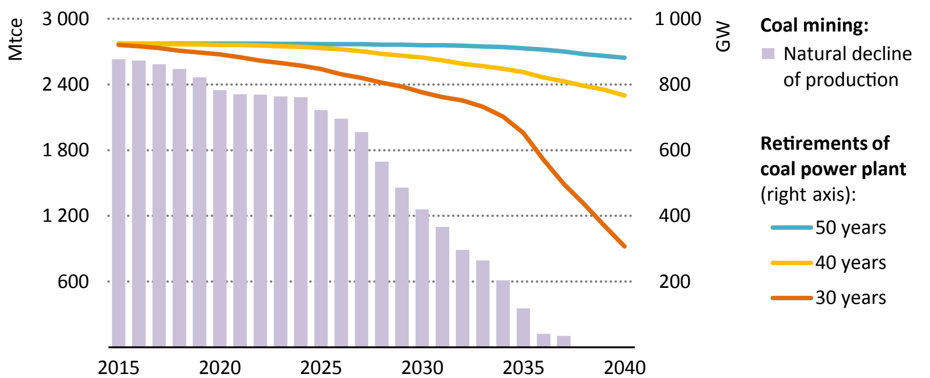
China plays a pivotal role in the global LNG balance in the New Policies Scenario. Based on a detailed analysis of supply contracts (concluded primarily by China's three large national oil and gas companies), our projections indicate that China is set to remain over-contracted through the early 2020s. Chinese importers have agreed to take more LNG than they currently need, but by the early 2020s projected imports of the New Policies Scenario are exceeding contracted volumes (Figure 15.14). This implies that Chinese importers will play an important role in the global LNG trade as they resell their over-contracted volumes. However, from the mid-2020s onwards, our projections also indicate that Chinese importers are short of contracted gas, which implies that they will need to enter the market to buy more. Higher than expected Chinese shale output in the 2020s would push back the point at which they need substantial additional volumes, potentially prolonging today's period of oversupply and sparking another round of fierce competition among exporters for market opportunities.

Coal markets

The links between China's policy choices and the global outlook are more profound for coal than for any other fuel. Even though China's consumption is projected to decline in the New Policies Scenario, China retains an immense presence in the global coal market, and the impacts of its policy choices are likely to be felt very quickly by coal producers and consumers around the world, and also by the producers and consumers of competing fuels. As described in the preceding Chapter 14 and in Chapter 5, an immediate policy priority is to deal with the overhang in production capacity, which requires a difficult balancing act.

The longer term challenges are no less profound, even once the Chinese coal market finds a new equilibrium (a point that is reached in our projections in the mid-2020s). China faces the prospect of a large decline in its coal production from the late 2020s, as the wave of mines that were opened in the early 2000s start to reach the end of their operational lifetimes (Figure 15.15). In the New Policies Scenario, we assume a decision to reinvest in new coal production capacity, in line with future projected domestic needs. China's coal consumption in this scenario is falling at a steady but measured pace by the 2020s – it declines by an average of 0.6% per year between 2020 and 2040 – and a precipitate decline in domestic output would have economic and social ramifications: it would also mean a sharp rise in imports.

Figure 15.15 ▷ Natural decline of coal production versus retirement rates for China's coal-fired capacity



The operational lifetimes of existing coal infrastructure, both on the supply and demand sides, presents China with a series of strategic choices in the 2020s

15

The age profile of China's mines and the prospect of declining output in the 2020s does present an opportunity for China's policy-makers to move away more decisively from coal during this period, if alternative technologies and fuels are deemed to provide adequate substitutes and the implications for employment appear manageable. However, as Figure 15.15 demonstrates, this would require a parallel step-change in China's coal-fired generation and a readiness to shut plants before the end of their operational life. In practice, this is the route that is taken in the Sustainable Development Scenario, although the pace at which China winds down its coal assets is slowed by the widespread deployment of CCS technologies (China has 150 GW of coal-fired capacity equipped with CCS by 2040, almost all of which is retrofitted).

Managing a parallel reduction in China's domestic supply and its coal-fired capacity would be a major challenge for policy-makers, with constant potential for movement on one side to overshoot the pace of change on the other. Any such imbalance would quickly be transmitted to international markets, via prices and fluctuations in the requirement for imported coal. It is possible that China could again become – even if only for short periods – a net exporter of coal, with huge impacts on international markets and prices.

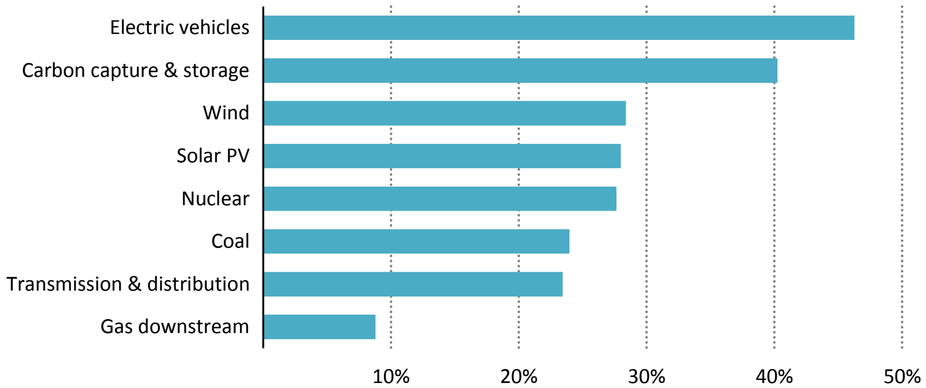
15.5.2 Low-carbon technologies

China has already assumed a global leadership role in many areas of clean energy technology. Today it has around one-third of the world's wind power capacity, a quarter of its solar power, six of the top-ten solar panel manufacturers, and four of the top-ten wind turbine manufacturers. In addition, China had more battery-only electric car sales in 2016 than the rest of the world combined. It has a commanding position in the manufacture and export of solar equipment, and its production capacity and expertise in batteries has grown very rapidly. This reflects the strategic priority given to the "new energy industry" in China as part of its shift to higher value-added manufacturing and an innovation-driven economy.

The push for new energy technologies is a central part of current policy thinking. The National Innovation-driven Development Strategy, issued by the State Council in 2016, states that, by 2020, the value added of the knowledge-intensive services sector should account for 20% of GDP and that the share of research and development in GDP should reach 2.5% (2.8% by 2030). As described in Chapter 13, the "Made in China 2025" initiative includes plans to develop smart "green" manufacturing technologies: the new energy industry also features prominently in the 13th Five-Year Plan on Energy Technology Innovation, and in the One Belt One Road initiative.

The projections in the New Policies Scenario reinforce China's position as a leader in clean technology. China accounts for a disproportionately high share of global investment in a range of technologies, including electric vehicles, CCS, wind power, solar PV and nuclear power (Figure 15.16). China is also actively pursuing a range of smart grid technologies, putting it at the leading edge of systems integration. For China, this commitment of capital has the potential to bring domestic environmental advantages together with industrial and

Figure 15.16 ▷ China's share of cumulative global investment in selected fuels and technologies in the New Policies Scenario, 2017-40



The effects of China's energy transition are reflected in its high shares of global investment in a range of low-carbon technologies in the New Policies Scenario

economic gains. For other countries, China's investments provide a powerful incentive to consider whether they are doing enough to develop competing clean technologies and products that can vie for market share. Meanwhile China's dominant role in the export of low-carbon technologies contributes to global CO_2 emissions savings as well as to its economy: in the New Policies Scenario, China's export of solar PV panels and lithium-ion batteries for electric vehicles alone contribute to global CO_2 emissions savings of nearly 1 Gt in 2040, equivalent to around 10% of China's energy-related CO_2 emissions in that year (Figure 15.17).

The same logic is further reinforced in the Sustainable Development Scenario. In this view to 2040, China consolidates its position as the leading global market for low-carbon technologies: a third of wind power, a quarter of solar PV, a quarter of concentrating solar power (CSP) and around 30% of nuclear power is installed in China, opening the way to rapid future technology learning. In this scenario, it also has the largest fleet of electric cars in the world – one-out-of-three electric cars in the world in 2040 are in China – and this gives it a powerful incentive to take a leading role in bringing down battery costs, with co-benefits in the form of lower energy storage costs for the power sector.

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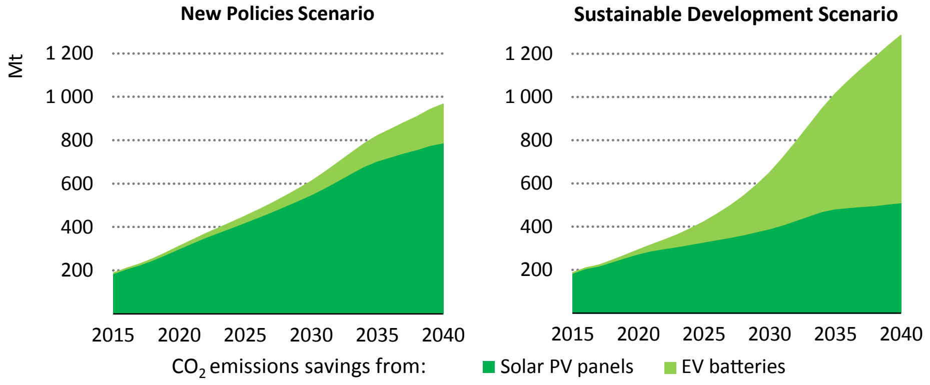
There is a possibility that China could break decisively from the conventional trajectories of energy development followed by advanced industrialised countries, providing a new model for low-carbon urbanisation and economic growth. In the Sustainable Development Scenario, China reaches its per-capita CO_2 emissions peak at a level of only a third of that of the United States and two-thirds of that of Japan and the European Union. The per-capita CO_2 peak is also reached at a GDP per-capita level two-thirds lower than Japan, less than half the level of the United States and more than 40% lower than the European Union. Such a clean energy pathway would be a powerful example for developing countries, which are looking to learn from the path that China has taken in the past, and the path that it is now taking into the future.

Figure 15.17 ▷ Global CO_2 emissions savings from China's export of solar PV panels and batteries for electric cars by scenario



China's exports of low-carbon technologies support worldwide CO_2 emissions savings

ANNEXES

Tables for scenario projections

General note to the tables

This Annex includes historical and projected data for the New Policies, Current Policies and Sustainable Development Scenarios for the following three data sets:

- A.1. Fossil-fuel production and demand by region.
- A.2. Energy demand, gross electricity generation and electrical capacity, and carbon-dioxide (CO_2) emissions from fossil-fuel combustion by region.
- A.3. Global emissions of pollutants by energy sector and fuel.

Geographical coverage for Tables A.1 and A.2 include: World, North America, Central and South America, Europe, Africa, Middle East, Eurasia, Asia Pacific, OECD and non-OECD. In addition, Table A.2 covers: United States, Brazil, European Union, South Africa, Russia, China, India, Japan and Southeast Asia.

The definitions for regions, fuels and sectors can be found in Annex C. By convention, in the table headings CPS and SDS refer to the Current Policies and Sustainable Development Scenarios respectively.

Both in the text of this book and in the tables, rounding may lead to minor differences between totals and the sum of their individual components. Growth rates are calculated on a compound average annual basis and are marked "n.a." when the base year is zero or the value exceeds 200%. Nil values are marked "-".

Please see Box A.1 for details on where to download these Annex A *World Energy Outlook (WEO)* tables in Excel format, as well as for links relating to the main *WEO* website, documentation and methodology of the World Energy Model, investment costs, policy databases and recent *WEO* special reports.

Data sources

Data for fossil-fuel production, energy demand, gross electricity generation and CO_2 emissions from fuel combustion up to 2015 are based on IEA statistics, (*www.iea.org/statistics*) published in *World Energy Balances*, *CO_2 Emissions from Fuel Combustion* and the IEA *Monthly Oil Data Service*. Historical data for gross electrical capacity are drawn from the Platts World Electric Power Plants Database (April 2017 version) and the International Atomic Energy Agency PRIS database (*www.iaea.org/pris*).

The formal base year for this year's projections is 2015, as this is the last year for which a complete picture of energy demand and supply is in place. However, we have used more recent data wherever available, and we include – for the first time – our 2016 estimates (marked as 2016e) for energy production and consumption in this Annex (Tables A.1 and A.2). Estimates for the year 2016 are derived from a number of sources, including the latest monthly data submissions to the IEA's Energy Data Centre, other statistical releases from national administrations and most recent market data also used in IEA *Market Report Series* for coal, oil, gas, renewables and power.

This Annex also includes, for the first time, projections for primary air pollutant emissions that are emitted directly as a result of human activity. The focus is on anthropogenic emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X) and fine particulate matter ($PM_{2.5}$). Only emissions related to energy activities are reported. The base year of the projections is 2015. Base year air pollutant emissions estimates and scenario projections stem from a coupling of sectoral activity and associated energy demand of the *WEO's* World Energy Model with the Greenhouse Gas and Air Pollution Interactions and Synergies (GAINS) model of the International Institute for Applied Systems Analysis (IIASA).[1]

Definitional note: A.1. Fossil-fuel production and demand tables

Oil production and demand is expressed in million barrels per day (mb/d). Tight oil includes tight crude oil and condensate production except for the United States, which includes tight crude oil only (US tight condensate volumes are included in natural gas liquids). Processing gains covers volume increases that occur during crude oil refining. Biofuels and liquids demand is expressed in energy-equivalent volumes of gasoline and diesel. Gas production and demand is expressed in billion cubic metres (bcm). Coal production and demand is expressed in million tonnes of coal equivalent (Mtce). Differences between historical supply and demand volumes for oil, gas and coal are due to changes in stocks. Bunkers includes international marine and aviation fuels.

Definitional note: A.2. Energy demand, electricity and CO_2 emissions tables

Total primary energy demand (TPED) is equivalent to power generation plus other energy sector excluding electricity and heat, plus total final consumption (TFC) excluding electricity and heat. TPED does not include ambient heat from heat pumps or electricity trade. Sectors comprising TFC include industry, transport, buildings (residential, services and non-specified other) and other (agriculture and non-energy use). Projected gross electrical capacity is the sum of existing capacity and additions, less retirements.

Total CO_2 includes emissions from other energy sector in addition to the power generation and TFC sectors shown in the tables. CO_2 emissions and energy demand from international marine and aviation bunkers are included only at the world transport level. Gas use in international bunkers is not itemised separately. CO_2 emissions do not include emissions from industrial waste and non-renewable municipal waste. Please visit *www.iea.org/statistics/topics/CO2emissions* for more information.

1. See: *www.iiasa.ac.at/web/home/research/researchPrograms/air/GAINS.html* for details.

Definitional note: A.3. Emissions of air pollutant tables

Emissions of all air pollutants are expressed in million tonnes per year and are reported by sector. The energy sector is broken down into power generation, industry and other transformation (i.e. other energy sector excluding electricity and heat), transport, buildings and agriculture. Emissions are reported separately for all energy activities and for combustion activities; the difference between these two relates to energy processes, including for example cement production in the industry sector or abrasion, tyres and brakes in road transport.

Box A.1 ▻ *World Energy Outlook* links

WEO-2017

General information: *www.iea.org/weo2017/*

WEO homepage

General information: *www.iea.org/weo/*

Modelling

Documentation and methodology / Investment costs / Policy databases
www.iea.org/weo/weomodel/

Recent WEO Special Reports

www.iea.org/weo/specialreports/

Energy Access Outlook: from Poverty to Prosperity
www.iea.org/access2017/

Southeast Asia Energy Outlook-2017
www.iea.org/southeastasia/

Energy and Air Pollution
www.iea.org/weo/airpollution/

Renewables
www.iea.org/weo/renewables/

Water
www.iea.org/weo/water/

New Policies Scenario

	Production							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Oil production and supply (mb/d)										
North America	14.2	20.0	19.4	24.9	25.4	25.0	24.5	21	24	1.0
Central & South America	6.8	7.8	7.5	7.9	8.3	9.0	10.0	8	10	1.2
Europe	7.1	3.7	3.7	3.6	3.3	2.9	2.6	4	3	-1.6
Africa	7.7	8.4	7.9	7.6	7.9	8.1	8.5	9	8	0.4
Middle East	23.5	29.8	31.7	32.7	34.4	36.1	37.7	34	37	0.7
Eurasia	7.9	14.0	14.1	13.7	13.1	12.5	11.9	15	12	-0.7
Asia Pacific	7.9	8.4	8.1	7.3	7.0	6.8	6.7	9	7	-0.8
OECD	21.9	23.9	23.4	29.0	29.2	28.5	27.7	25	27	0.7
Non-OECD	53.3	68.2	69.0	68.8	70.3	72.0	74.1	75	73	0.3
World production	**75.2**	**92.1**	**92.4**	**97.8**	**99.4**	**100.5**	**101.9**	**100**	**100**	**0.4**
Conventional crude oil	*64.8*	*67.5*	*67.6*	*64.6*	*64.3*	*63.6*	*64.1*	*71*	*61*	*-0.2*
Tight oil	-	*4.7*	*4.5*	*9.0*	*9.3*	*9.6*	*9.2*	*5*	*9*	*3.0*
Natural gas liquids	*9.0*	*15.8*	*16.2*	*18.5*	*19.8*	*20.6*	*20.8*	*17*	*20*	*1.0*
Extra-heavy oil & bitumen	*0.8*	*3.2*	*3.3*	*4.4*	*4.6*	*5.0*	*5.7*	*3*	*5*	*2.3*
Processing gains	1.8	2.2	2.3	2.5	2.7	2.9	3.1	2	3	1.3
World supply	**77.0**	**94.3**	**94.6**	**100.3**	**102.2**	**103.4**	**104.9**	**100**	**100**	**0.4**
Natural gas production (bcm)										
North America	763	973	960	1 166	1 212	1 282	1 338	27	25	1.4
Central & South America	102	172	175	178	207	242	279	5	5	2.0
Europe	337	289	285	244	238	236	236	8	4	-0.8
Africa	124	198	205	273	330	392	460	6	9	3.4
Middle East	198	576	585	703	832	931	1 003	16	19	2.3
Eurasia	691	841	842	935	978	1 035	1 095	23	21	1.1
Asia Pacific	290	542	568	675	749	832	894	16	17	1.9
OECD	1 109	1 304	1 310	1 539	1 590	1 678	1 738	36	33	1.2
Non-OECD	1 396	2 287	2 310	2 634	2 956	3 271	3 566	64	67	1.8
World	**2 506**	**3 592**	**3 621**	**4 174**	**4 545**	**4 950**	**5 304**	**100**	**100**	**1.6**
Shale gas	*22*	*435*	*462*	*820*	*950*	*1 068*	*1 188*	*13*	*22*	*4.0*
Coal production (Mtce)										
North America	824	671	566	537	514	499	489	11	9	-0.6
Central & South America	48	88	91	91	91	91	95	2	2	0.2
Europe	396	272	242	187	151	117	106	5	2	-3.4
Africa	187	221	216	234	238	246	276	4	5	1.0
Middle East	1	1	1	1	1	0	0	0	0	-4.8
Eurasia	234	357	362	367	371	371	378	7	7	0.2
Asia Pacific	1 564	3 919	3 793	4 072	4 199	4 259	4 269	72	76	0.5
OECD	1 381	1 317	1 173	1 090	1 052	1 015	1 026	22	18	-0.6
Non-OECD	1 873	4 214	4 098	4 398	4 514	4 569	4 587	78	82	0.5
World	**3 254**	**5 531**	**5 271**	**5 488**	**5 566**	**5 584**	**5 613**	**100**	**100**	**0.3**
Steam coal	*2 504*	*4 254*	*4 049*	*4 319*	*4 451*	*4 519*	*4 574*	*77*	*81*	*0.5*
Coking coal	*449*	*994*	*967*	*900*	*863*	*826*	*806*	*18*	*14*	*-0.8*

Current Policies and Sustainable Development Scenarios

	Production						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Oil production and supply (mb/d)										
North America	25.9	26.8	26.5	23.1	21.8	16.7	23	24	1.3	-0.6
Central & South America	8.3	9.2	11.9	7.1	6.6	6.1	10	9	1.9	-0.9
Europe	3.7	3.5	2.8	3.4	2.9	1.8	2	3	-1.3	-3.0
Africa	8.1	8.8	10.3	6.7	6.7	5.9	9	8	1.1	-1.2
Middle East	33.5	36.3	42.1	30.4	29.3	26.5	37	37	1.2	-0.7
Eurasia	14.2	14.0	13.8	12.8	11.6	9.5	12	13	-0.1	-1.6
Asia Pacific	7.6	7.6	8.0	6.6	5.6	4.3	7	6	-0.1	-2.6
OECD	30.1	30.8	30.0	26.9	25.2	19.0	26	27	1.0	-0.9
Non-OECD	71.3	75.4	85.3	63.2	59.3	51.8	74	73	0.9	-1.2
World production	**101.4**	**106.2**	**115.4**	**90.1**	**84.5**	**70.8**	**100**	**100**	**0.9**	**-1.1**
Conventional crude oil	*66.8*	*68.7*	*73.2*	*59.0*	*53.5*	*43.9*	*62*	*60*	*0.3*	*-1.8*
Tight oil	*9.4*	*10.1*	*9.8*	*8.1*	*8.0*	*6.4*	*8*	*9*	*3.3*	*1.4*
Natural gas liquids	*19.3*	*20.8*	*22.7*	*17.7*	*17.9*	*15.9*	*19*	*22*	*1.4*	*-0.1*
Extra-heavy oil & bitumen	*4.6*	*5.0*	*6.9*	*4.1*	*3.8*	*3.4*	*6*	*5*	*3.2*	*0.1*
Processing gains	2.6	2.9	3.5	2.3	2.3	2.1	3	3	1.8	-0.2
World supply	**104.1**	**109.1**	**118.8**	**92.4**	**86.8**	**72.9**	**100**	**100**	**1.0**	**-1.1**
Natural gas production (bcm)										
North America	1 205	1 256	1 396	1 159	1 154	972	24	23	1.6	0.1
Central & South America	180	217	310	175	186	186	5	4	2.4	0.2
Europe	243	240	238	241	235	228	4	5	-0.8	-0.9
Africa	278	349	502	264	297	334	9	8	3.8	2.0
Middle East	718	859	1 087	689	745	730	19	17	2.6	0.9
Eurasia	961	1 020	1 210	920	899	892	21	21	1.5	0.2
Asia Pacific	685	779	961	679	753	875	17	21	2.2	1.8
OECD	1 583	1 643	1 819	1 535	1 534	1 348	32	32	1.4	0.1
Non-OECD	2 687	3 077	3 885	2 592	2 734	2 868	68	68	2.2	0.9
World	**4 270**	**4 720**	**5 704**	**4 127**	**4 269**	**4 216**	**100**	**100**	**1.9**	**0.6**
Shale gas	*841*	*993*	*1 311*	*735*	*828*	*901*	*23*	*21*	*4.4*	*2.8*
Coal production (Mtce)										
North America	585	576	560	262	130	102	8	4	-0.0	-6.9
Central & South America	108	113	122	77	69	27	2	1	1.2	-4.9
Europe	209	180	151	136	86	43	2	2	-1.9	-6.9
Africa	252	275	348	191	167	127	5	5	2.0	-2.2
Middle East	1	1	1	1	1	0	0	0	0.8	-4.8
Eurasia	412	436	471	282	243	225	7	9	1.1	-2.0
Asia Pacific	4 384	4 795	5 555	3 370	2 817	2 014	77	79	1.6	-2.6
OECD	1 214	1 218	1 237	676	478	384	17	15	0.2	-4.5
Non-OECD	4 736	5 157	5 971	3 643	3 032	2 155	83	85	1.6	-2.6
World	**5 950**	**6 375**	**7 208**	**4 318**	**3 511**	**2 539**	**100**	**100**	**1.3**	**-3.0**
Steam coal	*4 734*	*5 187*	*6 040*	*3 300*	*2 629*	*1 834*	*84*	*72*	*1.7*	*-3.2*
Coking coal	*923*	*901*	*875*	*826*	*739*	*595*	*12*	*23*	*-0.4*	*-2.0*

New Policies Scenario

	Demand							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Oil and liquids demand (mb/d)										
North America	22.9	22.3	22.3	21.8	20.5	19.0	18.0	24	17	-0.9
Central & South America	4.5	6.0	5.9	6.2	6.3	6.5	6.7	6	6	0.5
Europe	14.9	12.8	13.0	11.3	10.3	9.4	8.7	14	8	-1.7
Africa	2.2	3.8	3.9	4.6	5.1	5.6	6.2	4	6	2.0
Middle East	4.3	7.7	7.6	8.6	9.1	9.9	10.7	8	10	1.4
Eurasia	3.1	3.7	3.9	4.3	4.4	4.4	4.4	4	4	0.6
Asia Pacific	19.4	28.9	29.6	34.8	37.0	38.3	39.2	32	37	1.2
OECD	45.0	41.6	41.8	38.7	35.9	33.1	31.0	45	30	-1.2
Non-OECD	26.3	43.6	44.4	52.8	56.7	60.0	62.8	47	60	1.5
Bunkers	5.4	7.5	7.7	8.8	9.5	10.3	11.1	8	11	1.6
World oil demand	**76.7**	**92.6**	**93.9**	**100.3**	**102.2**	**103.4**	**104.9**	**100**	**100**	**0.5**
World biofuels	0.2	1.6	1.7	2.5	3.1	3.6	4.1	2	4	3.9
World liquids demand	**76.9**	**94.2**	**95.5**	**102.8**	**105.3**	**107.0**	**109.1**	**100**	**100**	**0.6**
Natural gas demand (bcm)										
North America	800	962	961	1 045	1 068	1 109	1 143	26	22	0.7
Central & South America	97	169	166	183	205	237	271	5	5	2.1
Europe	606	558	590	604	618	633	631	16	12	0.3
Africa	57	131	134	177	211	251	306	4	6	3.5
Middle East	174	462	477	568	657	737	795	13	15	2.2
Eurasia	471	561	575	583	593	615	636	16	12	0.4
Asia Pacific	314	702	732	998	1 167	1 331	1 472	20	28	3.0
OECD	1 418	1 653	1 694	1 774	1 822	1 888	1 924	47	36	0.5
Non-OECD	1 100	1 891	1 941	2 383	2 697	3 024	3 329	53	63	2.3
Bunkers	0	0	0	16	26	37	51	0	1	n.a.
World	**2 518**	**3 544**	**3 635**	**4 174**	**4 545**	**4 950**	**5 304**	**100**	**100**	**1.6**
Coal demand (Mtce)										
North America	817	580	525	481	466	455	439	10	8	-0.7
Central & South America	29	48	49	53	55	57	60	1	1	0.8
Europe	578	498	464	383	327	266	244	9	4	-2.6
Africa	128	154	151	160	167	178	201	3	4	1.2
Middle East	2	4	4	7	8	9	9	0	0	3.7
Eurasia	202	220	212	221	219	222	220	4	4	0.1
Asia Pacific	1 544	3 972	3 960	4 184	4 324	4 397	4 439	74	79	0.5
OECD	1 565	1 357	1 266	1 094	1 003	906	853	24	15	-1.6
Non-OECD	1 736	4 119	4 098	4 395	4 563	4 678	4 760	76	85	0.6
World	**3 301**	**5 475**	**5 364**	**5 488**	**5 566**	**5 584**	**5 613**	**100**	**100**	**0.2**

Current Policies and Sustainable Development Scenarios

	Demand						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Oil and liquids demand (mb/d)										
North America	22.5	21.8	20.5	20.1	17.4	12.1	17	17	-0.4	-2.5
Central & South America	6.4	6.7	7.6	5.6	5.2	4.4	6	6	1.0	-1.2
Europe	11.8	11.2	10.4	10.4	8.6	5.7	9	8	-0.9	-3.4
Africa	4.7	5.4	7.0	4.3	4.6	4.9	6	7	2.5	1.0
Middle East	8.8	9.5	11.9	7.9	7.6	7.2	10	10	1.9	-0.2
Eurasia	4.3	4.5	4.8	4.1	4.1	3.7	4	5	0.9	-0.2
Asia Pacific	36.2	39.5	44.0	33.0	32.7	29.0	37	40	1.7	-0.1
OECD	39.9	38.3	35.6	35.7	30.4	21.1	30	29	-0.7	-2.8
Non-OECD	54.8	60.4	70.5	49.7	49.8	46.0	59	63	1.9	0.2
Bunkers	9.4	10.4	12.8	7.0	6.6	5.8	11	8	2.1	-1.1
World oil demand	**104.1**	**109.1**	**118.8**	**92.4**	**86.8**	**72.9**	**100**	**100**	**1.0**	**-1.0**
World biofuels	2.2	2.5	3.2	4.0	5.6	7.4	3	9	2.8	6.4
World liquids demand	**106.3**	**111.7**	**122.1**	**96.5**	**92.4**	**80.3**	**100**	**100**	**1.0**	**-0.7**
Natural gas demand (bcm)										
North America	1 075	1 116	1 229	1 061	1 009	822	22	19	1.0	-0.6
Central & South America	190	219	303	166	172	182	5	4	2.5	0.4
Europe	635	679	740	593	556	471	13	11	0.9	-0.9
Africa	180	221	323	157	165	188	6	4	3.7	1.4
Middle East	586	691	886	537	579	547	16	13	2.6	0.6
Eurasia	596	616	685	560	536	508	12	12	0.7	-0.5
Asia Pacific	998	1 161	1 501	1 019	1 209	1 441	26	34	3.0	2.9
OECD	1 826	1 911	2 098	1 769	1 688	1 374	37	33	0.9	-0.9
Non-OECD	2 434	2 792	3 568	2 324	2 539	2 786	63	66	2.6	1.5
Bunkers	10	17	38	33	41	57	1	1	n.a.	n.a.
World	**4 270**	**4 720**	**5 704**	**4 127**	**4 269**	**4 217**	**100**	**100**	**1.9**	**0.6**
Coal demand (Mtce)										
North America	520	512	501	224	94	69	7	3	-0.2	-8.1
Central & South America	57	62	70	43	34	28	1	1	1.5	-2.3
Europe	430	391	348	262	187	133	5	5	-1.2	-5.1
Africa	169	189	255	135	124	114	4	5	2.2	-1.1
Middle East	7	8	9	7	7	7	0	0	4.0	2.6
Eurasia	229	234	238	178	148	105	3	4	0.5	-2.9
Asia Pacific	4 539	4 979	5 786	3 470	2 916	2 082	80	82	1.6	-2.6
OECD	1 200	1 152	1 094	676	396	277	15	11	-0.6	-6.1
Non-OECD	4 751	5 224	6 114	3 643	3 114	2 261	85	89	1.7	-2.4
World	**5 950**	**6 375**	**7 208**	**4 318**	**3 510**	**2 539**	**100**	**100**	**1.2**	**-3.1**

World: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**10 035**	**13 633**	**13 760**	**15 182**	**16 011**	**16 806**	**17 584**	**100**	**100**	**1.0**
Coal	2 311	3 837	3 755	3 842	3 896	3 909	3 929	27	22	0.2
Oil	3 670	4 327	4 388	4 633	4 715	4 764	4 830	32	27	0.4
Gas	2 071	2 938	3 007	3 436	3 737	4 068	4 356	22	25	1.6
Nuclear	676	671	681	839	897	949	1 002	5	6	1.6
Hydro	225	334	350	413	459	499	533	3	3	1.8
Bioenergy	1 023	1 326	1 354	1 530	1 630	1 721	1 801	10	10	1.2
Other renewables	60	200	225	490	676	896	1 133	2	6	7.0
Power generation	**3 643**	**5 186**	**5 252**	**5 809**	**6 224**	**6 656**	**7 094**	**100**	**100**	**1.3**
Coal	1 565	2 368	2 324	2 338	2 361	2 352	2 351	44	33	0.0
Oil	322	277	275	200	172	152	137	5	2	-2.9
Gas	747	1 203	1 257	1 340	1 450	1 577	1 682	24	24	1.2
Nuclear	676	671	681	839	897	949	1 002	13	14	1.6
Hydro	225	334	350	413	459	499	533	7	8	1.8
Bioenergy	57	171	182	264	310	362	418	3	6	3.5
Other renewables	51	162	183	416	576	765	971	3	14	7.2
Other energy sector	**977**	**1 491**	**1 486**	**1 600**	**1 661**	**1 717**	**1 770**	**100**	**100**	**0.7**
Electricity	*239*	*348*	*356*	*392*	*425*	*460*	*495*	*24*	*28*	*1.4*
TFC	**7 039**	**9 370**	**9 486**	**10 672**	**11 306**	**11 896**	**12 461**	**100**	**100**	**1.1**
Coal	548	1 039	1 020	1 066	1 080	1 088	1 092	11	9	0.3
Oil	3 117	3 818	3 878	4 191	4 307	4 389	4 481	41	36	0.6
Gas	1 117	1 407	1 426	1 746	1 927	2 106	2 268	15	18	2.0
Electricity	1 092	1 740	1 777	2 159	2 405	2 652	2 895	19	23	2.1
Heat	249	271	274	295	299	302	303	3	2	0.4
Bioenergy	908	1 056	1 069	1 142	1 188	1 228	1 260	11	10	0.7
Other renewables	9	38	42	74	100	132	162	0	1	5.8
Industry	**1 867**	**2 797**	**2 826**	**3 270**	**3 490**	**3 698**	**3 895**	**100**	**100**	**1.3**
Coal	401	822	812	865	893	916	936	29	24	0.6
Oil	327	331	339	355	356	355	353	12	9	0.2
Gas	414	596	607	760	838	916	995	21	26	2.1
Electricity	462	730	745	903	983	1 058	1 127	26	29	1.7
Heat	101	124	127	143	144	144	142	4	4	0.5
Bioenergy	162	193	196	242	271	300	328	7	8	2.2
Other renewables	0	1	1	2	5	9	13	0	0	12.7
Transport	**1 958**	**2 692**	**2 722**	**3 028**	**3 191**	**3 335**	**3 494**	**100**	**100**	**1.0**
Oil	1 867	2 480	2 505	2 692	2 772	2 829	2 899	92	83	0.6
Of which: bunkers	*273*	*379*	*387*	*443*	*479*	*518*	*559*	*14*	*16*	*1.5*
Electricity	19	36	37	58	75	98	122	1	3	5.1
Biofuels	10	76	78	120	149	174	200	3	6	4.0
Other fuels	62	100	102	158	194	234	273	4	8	4.2
Buildings	**2 451**	**2 957**	**2 993**	**3 227**	**3 407**	**3 588**	**3 752**	**100**	**100**	**0.9**
Coal	108	133	128	106	90	75	62	4	2	-3.0
Oil	346	321	327	304	290	277	271	11	7	-0.8
Gas	533	628	632	713	771	824	861	21	23	1.3
Electricity	582	917	937	1 124	1 265	1 407	1 552	31	41	2.1
Heat	142	144	145	149	152	155	158	5	4	0.4
Bioenergy	731	778	785	763	749	731	705	26	19	-0.4
Traditional biomass	*646*	*673*	*678*	*642*	*619*	*591*	*557*	*23*	*15*	*-0.8*
Other renewables	8	36	39	68	91	118	143	1	4	5.6
Other	**764**	**923**	**945**	**1 148**	**1 218**	**1 275**	**1 320**	**100**	**100**	**1.4**
Petrochem. feedstock	*442*	*510*	*530*	*679*	*730*	*777*	*817*	*18*	*22*	*1.8*

World: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**15 690**	**16 891**	**19 299**	**13 921**	**13 836**	**14 084**	**100**	**100**	**1.4**	**0.1**
Coal	4 165	4 463	5 045	3 023	2 457	1 777	26	13	1.2	-3.1
Oil	4 815	5 047	5 477	4 247	3 966	3 306	28	23	0.9	-1.2
Gas	3 514	3 879	4 682	3 397	3 510	3 458	24	25	1.9	0.6
Nuclear	839	900	997	920	1 120	1 393	5	10	1.6	3.0
Hydro	409	447	513	429	489	596	3	4	1.6	2.2
Bioenergy	1 507	1 586	1 728	1 272	1 258	1 558	9	11	1.0	0.6
Other renewables	441	570	856	633	1 037	1 996	4	14	5.7	9.5
Power generation	**6 090**	**6 685**	**7 925**	**5 313**	**5 426**	**5 988**	**100**	**100**	**1.7**	**0.5**
Coal	2 612	2 836	3 285	1 618	1 110	578	41	10	1.5	-5.6
Oil	204	177	144	167	120	62	2	1	-2.7	-6.0
Gas	1 394	1 551	1 898	1 359	1 346	1 113	24	19	1.7	-0.5
Nuclear	839	900	997	920	1 120	1 393	13	23	1.6	3.0
Hydro	409	447	513	429	489	596	6	10	1.6	2.2
Bioenergy	255	288	360	285	353	511	5	9	2.9	4.4
Other renewables	377	487	728	534	889	1 735	9	29	5.9	9.8
Other energy sector	**1 656**	**1 763**	**1 988**	**1 439**	**1 397**	**1 326**	**100**	**100**	**1.2**	**-0.5**
Electricity	*415*	*462*	*561*	*364*	*375*	*410*	*28*	*31*	*1.9*	*0.6*
TFC	**10 944**	**11 788**	**13 420**	**9 933**	**9 971**	**10 174**	**100**	**100**	**1.5**	**0.3**
Coal	1 107	1 151	1 219	999	947	818	9	8	0.7	-0.9
Oil	4 357	4 615	5 099	3 860	3 651	3 104	38	31	1.1	-0.9
Gas	1 760	1 949	2 325	1 706	1 835	2 040	17	20	2.1	1.5
Electricity	2 226	2 514	3 090	2 066	2 258	2 699	23	27	2.3	1.8
Heat	303	314	330	285	279	259	2	3	0.8	-0.2
Bioenergy	1 126	1 163	1 228	920	855	994	9	10	0.6	-0.3
Other renewables	64	83	128	98	148	261	1	3	4.8	7.9
Industry	**3 340**	**3 621**	**4 160**	**3 120**	**3 185**	**3 280**	**100**	**100**	**1.6**	**0.6**
Coal	892	941	1 025	809	782	708	25	22	1.0	-0.6
Oil	361	368	371	336	323	298	9	9	0.4	-0.5
Gas	767	856	1 040	732	775	840	25	26	2.3	1.4
Electricity	923	1 021	1 207	857	888	955	29	29	2.0	1.0
Heat	148	154	160	138	132	115	4	4	1.0	-0.4
Bioenergy	247	280	348	240	267	322	8	10	2.4	2.1
Other renewables	2	3	7	8	19	43	0	1	9.9	18.3
Transport	**3 115**	**3 361**	**3 871**	**2 848**	**2 829**	**2 708**	**100**	**100**	**1.5**	**-0.0**
Oil	2 825	3 025	3 424	2 404	2 193	1 668	88	62	1.3	-1.7
Of which: bunkers	*471*	*525*	*643*	*352*	*335*	*295*	*17*	*11*	*2.1*	*-1.1*
Electricity	48	55	73	66	118	293	2	11	2.9	9.0
Biofuels	103	119	156	200	284	393	4	15	2.9	7.0
Other fuels	140	161	218	177	233	354	6	13	3.2	5.3
Buildings	**3 332**	**3 569**	**4 025**	**2 837**	**2 771**	**2 917**	**100**	**100**	**1.2**	**-0.1**
Coal	117	109	91	99	75	26	2	1	-1.4	-6.5
Oil	326	324	322	294	272	224	8	8	-0.1	-1.6
Gas	738	808	928	683	707	714	23	24	1.6	0.5
Electricity	1 178	1 351	1 704	1 071	1 175	1 366	42	47	2.5	1.6
Heat	152	157	167	144	143	140	4	5	0.6	-0.1
Bioenergy	760	744	697	460	276	238	17	8	-0.5	-4.8
Traditional biomass	*642*	*619*	*557*	*340*	*148*	*102*	*14*	*3*	*-0.8*	*-7.6*
Other renewables	60	77	117	86	123	208	3	7	4.7	7.2
Other	**1 157**	**1 237**	**1 365**	**1 129**	**1 186**	**1 268**	**100**	**100**	**1.5**	**1.2**
Petrochem. feedstock	*678*	*732*	*829*	*672*	*718*	*801*	*21*	*27*	*1.9*	*1.7*

World: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**15 477**	**24 240**	**24 770**	**29 657**	**32 864**	**36 097**	**39 290**	**100**	**100**	**1.9**
Coal	6 005	9 532	9 282	9 675	9 880	9 968	10 086	37	26	0.3
Oil	1 259	1 022	1 006	719	621	549	491	4	1	-2.9
Gas	2 753	5 519	5 850	6 730	7 581	8 443	9 181	24	23	1.9
Nuclear	2 591	2 571	2 611	3 217	3 440	3 642	3 844	11	10	1.6
Renewables	2 869	5 595	6 021	9 316	11 343	13 495	15 688	24	40	4.1
Hydro	2 619	3 888	4 070	4 804	5 344	5 801	6 193	16	16	1.8
Bioenergy	164	531	570	867	1 036	1 225	1 424	2	4	3.9
Wind	31	838	981	2 192	2 837	3 547	4 270	4	11	6.3
Geothermal	52	80	86	140	197	269	349	0	1	6.0
Solar PV	1	247	303	1 264	1 827	2 471	3 162	1	8	10.3
CSP	1	10	11	44	89	154	237	0	1	13.8
Marine	1	1	1	4	12	28	53	0	0	17.0

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**6 414**	**6 677**	**8 647**	**9 725**	**10 857**	**11 960**	**100**	**100**	**2.5**
Coal	1 963	2 020	2 228	2 296	2 360	2 434	30	20	0.8
Oil	439	443	334	287	259	233	7	2	-2.6
Gas	1 621	1 650	2 087	2 325	2 571	2 800	25	23	2.2
Nuclear	404	413	448	468	492	516	6	4	0.9
Renewables	1 986	2 151	3 550	4 349	5 175	5 978	32	50	4.4
Hydro	1 209	1 241	1 460	1 606	1 729	1 830	19	15	1.6
Bioenergy	120	127	180	210	241	273	2	2	3.2
Wind	414	466	932	1 174	1 424	1 664	7	14	5.5
Geothermal	13	13	21	29	40	51	0	0	5.8
Solar PV	225	299	939	1 295	1 682	2 067	4	17	8.4
CSP	5	5	16	30	49	72	0	1	11.9
Marine	1	1	2	5	11	21	0	0	16.5

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**23 013**	**32 077**	**32 072**	**33 387**	**34 259**	**34 970**	**35 692**	**100**	**100**	**0.4**
Coal	8 952	14 487	14 216	14 301	14 392	14 330	14 300	44	40	0.0
Oil	9 512	11 136	11 216	11 526	11 629	11 687	11 819	35	33	0.2
Gas	4 549	6 454	6 640	7 561	8 238	8 954	9 573	21	27	1.5
Power generation	**9 243**	**13 422**	**13 353**	**13 329**	**13 561**	**13 730**	**13 899**	**100**	**100**	**0.2**
Coal	6 454	9 714	9 527	9 547	9 610	9 542	9 512	71	68	-0.0
Oil	1 033	873	862	627	538	476	430	6	3	-2.9
Gas	1 756	2 834	2 963	3 155	3 413	3 712	3 957	22	28	1.2
TFC	**12 593**	**17 012**	**17 074**	**18 354**	**18 980**	**19 505**	**20 035**	**100**	**100**	**0.7**
Coal	2 318	4 399	4 326	4 411	4 450	4 468	4 477	25	22	0.1
Oil	7 904	9 670	9 740	10 287	10 491	10 621	10 803	57	54	0.4
Transport	*5 589*	*7 442*	*7 520*	*8 084*	*8 328*	*8 501*	*8 712*	*44*	*43*	*0.6*
Of which: bunkers	*843*	*1 164*	*1 191*	*1 361*	*1 468*	*1 585*	*1 710*	*7*	*9*	*1.5*
Gas	2 371	2 943	3 008	3 656	4 039	4 417	4 755	18	24	1.9

World: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**30 724**	**34 583**	**42 321**	**28 226**	**30 547**	**35 981**	**100**	**100**	**2.3**	**1.6**
Coal	10 897	12 039	14 386	6 575	4 472	2 195	34	6	1.8	-5.8
Oil	736	643	523	593	412	192	1	1	-2.7	-6.7
Gas	7 033	8 159	10 428	6 903	6 950	5 585	25	16	2.4	-0.2
Nuclear	3 218	3 452	3 825	3 531	4 295	5 345	9	15	1.6	3.0
Renewables	8 840	10 290	13 160	10 625	14 417	22 664	31	63	3.3	5.7
Hydro	4 755	5 202	5 964	4 986	5 688	6 928	14	19	1.6	2.2
Bioenergy	833	953	1 211	952	1 209	1 807	3	5	3.2	4.9
Wind	1 983	2 431	3 358	2 785	4 193	6 950	8	19	5.3	8.5
Geothermal	134	178	281	170	292	563	1	2	5.1	8.2
Solar PV	1 096	1 460	2 192	1 629	2 732	5 265	5	15	8.6	12.6
CSP	36	58	130	99	287	1 066	0	3	11.0	21.1
Marine	3	7	25	5	17	85	0	0	13.3	19.4

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**8 564**	**9 557**	**11 495**	**8 899**	**10 238**	**13 100**	**100**	**100**	**2.3**	**2.8**
Coal	2 341	2 534	2 955	1 991	1 686	1 150	26	9	1.6	-2.3
Oil	336	293	242	323	274	210	2	2	-2.5	-3.1
Gas	2 138	2 424	2 984	1 938	2 032	2 297	26	18	2.5	1.4
Nuclear	450	472	513	491	586	720	4	5	0.9	2.3
Renewables	3 298	3 834	4 801	4 157	5 661	8 724	42	67	3.4	6.0
Hydro	1 441	1 558	1 757	1 527	1 723	2 060	15	16	1.5	2.1
Bioenergy	174	194	234	196	243	347	2	3	2.6	4.3
Wind	842	1 006	1 305	1 184	1 706	2 629	11	20	4.4	7.5
Geothermal	20	26	41	26	44	82	0	1	4.8	7.9
Solar PV	807	1 027	1 416	1 188	1 846	3 246	12	25	6.7	10.4
CSP	13	20	39	35	92	328	0	3	9.0	19.2
Marine	1	3	9	2	7	34	0	0	12.6	18.8

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**35 419**	**37 828**	**42 718**	**28 799**	**25 146**	**18 310**	**100**	**100**	**1.2**	**-2.3**
Coal	15 607	16 650	18 671	10 955	8 158	4 102	44	22	1.1	-5.0
Oil	12 062	12 608	13 751	10 386	9 403	7 234	32	40	0.9	-1.8
Gas	7 750	8 570	10 297	7 458	7 585	6 974	24	38	1.8	0.2
Power generation	**14 595**	**15 768**	**18 254**	**10 314**	**7 719**	**3 688**	**100**	**100**	**1.3**	**-5.2**
Coal	10 673	11 563	13 336	6 592	4 244	1 208	73	33	1.4	-8.2
Oil	639	554	452	524	375	195	2	5	-2.7	-6.0
Gas	3 283	3 651	4 465	3 198	3 101	2 285	24	62	1.7	-1.1
TFC	**19 058**	**20 236**	**22 492**	**16 935**	**16 013**	**13 505**	**100**	**100**	**1.2**	**-1.0**
Coal	4 581	4 738	4 991	4 054	3 648	2 697	22	20	0.6	-1.9
Oil	10 788	11 411	12 627	9 315	8 554	6 689	56	50	1.1	-1.6
Transport	*8 485*	*9 089*	*10 290*	*7 214*	*6 582*	*5 009*	*46*	*37*	*1.3*	*-1.7*
Of which: bunkers	*1 447*	*1 612*	*1 968*	*1 080*	*1 028*	*903*	*9*	*7*	*2.1*	*-1.1*
Gas	3 689	4 086	4 874	3 567	3 812	4 118	22	30	2.0	1.3

North America: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**2 678**	**2 645**	**2 615**	**2 672**	**2 660**	**2 652**	**2 668**	**100**	**100**	**0.1**
Coal	572	406	368	337	326	318	308	14	12	-0.7
Oil	1 048	979	979	948	892	827	788	37	30	-0.9
Gas	657	798	793	863	882	916	944	30	35	0.7
Nuclear	229	246	248	224	222	213	214	9	8	-0.6
Hydro	55	57	59	65	68	69	71	2	3	0.8
Bioenergy	96	121	124	145	159	171	183	5	7	1.6
Other renewables	20	38	44	90	112	137	162	2	6	5.6
Power generation	**1 071**	**1 040**	**1 029**	**1 007**	**1 019**	**1 036**	**1 059**	**100**	**100**	**0.1**
Coal	533	365	331	301	292	282	271	32	26	-0.8
Oil	56	18	17	6	5	4	3	2	0	-7.5
Gas	155	291	305	299	301	312	322	30	30	0.2
Nuclear	229	246	248	224	222	213	214	24	20	-0.6
Hydro	55	57	59	65	68	69	71	6	7	0.8
Bioenergy	24	27	28	31	33	36	40	3	4	1.5
Other renewables	18	35	41	81	99	119	139	4	13	5.2
Other energy sector	**199**	**238**	**222**	**263**	**271**	**283**	**295**	**100**	**100**	**1.2**
Electricity	*61*	*64*	*64*	*64*	*65*	*66*	*68*	*29*	*23*	*0.2*
TFC	**1 833**	**1 833**	**1 831**	**1 895**	**1 879**	**1 859**	**1 862**	**100**	**100**	**0.1**
Coal	37	26	25	25	23	22	21	1	1	-0.7
Oil	935	920	923	891	833	772	733	50	39	-1.0
Gas	426	394	385	432	444	455	465	21	25	0.8
Electricity	355	391	392	419	435	453	473	21	25	0.8
Heat	6	6	6	6	6	5	5	0	0	-1.1
Bioenergy	72	94	96	114	125	135	143	5	8	1.7
Other renewables	2	3	3	9	13	17	22	0	1	8.3
Industry	**420**	**349**	**349**	**381**	**383**	**385**	**390**	**100**	**100**	**0.5**
Coal	34	25	25	24	23	22	21	7	5	-0.7
Oil	44	33	33	33	31	30	30	9	8	-0.4
Gas	168	154	153	175	175	175	176	44	45	0.6
Electricity	123	96	96	105	107	110	114	28	29	0.7
Heat	5	5	5	5	5	4	4	1	1	-0.9
Bioenergy	45	36	37	39	41	42	45	10	11	0.8
Other renewables	0	0	0	0	1	1	1	0	0	20.9
Transport	**676**	**741**	**744**	**716**	**684**	**651**	**638**	**100**	**100**	**-0.6**
Oil	652	685	686	637	585	533	503	92	79	-1.3
Electricity	1	1	1	4	6	10	14	0	2	10.4
Biofuels	3	35	36	48	56	61	66	5	10	2.5
Other fuels	20	20	19	28	37	47	55	3	9	4.4
Buildings	**540**	**570**	**562**	**588**	**600**	**613**	**625**	**100**	**100**	**0.4**
Coal	2	1	1	0	0	0	0	0	0	-10.3
Oil	67	47	47	40	35	29	24	8	4	-2.7
Gas	215	209	200	208	209	211	211	36	34	0.2
Electricity	230	288	289	305	317	328	340	51	54	0.7
Heat	1	1	1	1	1	1	1	0	0	-1.8
Bioenergy	24	22	22	24	26	28	29	4	5	1.3
Traditional biomass	-	-	-	-	-	-	-	-	-	*n.a.*
Other renewables	2	3	3	8	12	16	20	1	3	7.8
Other	**197**	**173**	**176**	**210**	**212**	**211**	**209**	**100**	**100**	**0.7**
Petrochem. feedstock	*120*	*91*	*94*	*121*	*122*	*120*	*118*	*17*	*19*	*0.9*

North America: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**2 742**	**2 779**	**2 875**	**2 496**	**2 353**	**2 164**	**100**	**100**	**0.4**	**-0.8**
Coal	364	359	351	156	66	49	12	2	-0.2	-8.1
Oil	979	953	900	869	748	520	31	24	-0.4	-2.6
Gas	888	921	1 015	876	833	679	35	31	1.0	-0.6
Nuclear	224	226	221	241	249	259	8	12	-0.5	0.2
Hydro	65	68	72	65	69	73	2	3	0.8	0.9
Bioenergy	142	154	180	175	209	248	6	11	1.6	2.9
Other renewables	81	98	135	113	179	337	5	16	4.8	8.8
Power generation	**1 046**	**1 078**	**1 139**	**915**	**871**	**908**	**100**	**100**	**0.4**	**-0.5**
Coal	328	323	308	124	37	23	27	3	-0.3	-10.5
Oil	7	6	3	5	4	2	0	0	-6.6	-9.1
Gas	317	331	372	346	313	195	33	22	0.8	-1.8
Nuclear	224	226	221	241	249	259	19	28	-0.5	0.2
Hydro	65	68	72	65	69	73	6	8	0.8	0.9
Bioenergy	31	33	39	33	40	57	3	6	1.4	3.0
Other renewables	75	91	124	101	159	300	11	33	4.7	8.7
Other energy sector	**272**	**287**	**328**	**244**	**236**	**210**	**100**	**100**	**1.6**	**-0.2**
Electricity	*66*	*69*	*73*	*59*	*57*	*56*	*22*	*27*	*0.5*	*-0.6*
TFC	**1 929**	**1 945**	**1 988**	**1 811**	**1 729**	**1 571**	**100**	**100**	**0.3**	**-0.6**
Coal	25	24	22	23	20	16	1	1	-0.6	-1.9
Oil	918	888	840	817	699	482	42	31	-0.4	-2.7
Gas	434	446	469	406	399	376	24	24	0.8	-0.1
Electricity	430	453	500	405	417	464	25	30	1.0	0.7
Heat	6	6	5	6	5	4	0	0	-0.9	-2.2
Bioenergy	111	121	141	142	169	191	7	12	1.6	2.9
Other renewables	5	7	12	13	20	37	1	2	5.4	10.7
Industry	**385**	**391**	**404**	**364**	**353**	**339**	**100**	**100**	**0.6**	**-0.1**
Coal	24	23	22	22	20	16	5	5	-0.5	-1.8
Oil	33	32	31	30	27	24	8	7	-0.3	-1.4
Gas	176	178	181	167	160	145	45	43	0.7	-0.2
Electricity	106	109	117	100	97	97	29	29	0.8	0.0
Heat	5	5	4	5	4	3	1	1	-0.8	-1.6
Bioenergy	40	43	49	40	43	49	12	14	1.2	1.2
Other renewables	0	0	1	1	2	5	0	2	20.5	29.0
Transport	**733**	**717**	**705**	**687**	**628**	**509**	**100**	**100**	**-0.2**	**-1.6**
Oil	661	634	600	573	467	275	85	54	-0.6	-3.7
Electricity	2	3	4	9	23	68	1	13	4.5	17.8
Biofuels	45	51	63	77	100	114	9	22	2.3	4.9
Other fuels	25	29	38	28	38	53	5	10	2.8	4.2
Buildings	**602**	**625**	**670**	**553**	**541**	**521**	**100**	**100**	**0.7**	**-0.3**
Coal	0	0	0	0	0	-	0	-	-3.0	-100
Oil	44	41	32	36	28	15	5	3	-1.6	-4.6
Gas	212	217	228	191	180	157	34	30	0.5	-1.0
Electricity	316	335	373	292	292	295	56	57	1.1	0.1
Heat	1	1	1	1	1	0	0	0	-1.5	-6.0
Bioenergy	23	24	26	23	22	24	4	5	0.8	0.4
Traditional biomass	-	-	-	-	-	-	-	-	*n.a.*	*n.a.*
Other renewables	5	6	10	11	17	30	1	6	4.8	9.7
Other	**210**	**212**	**209**	**206**	**207**	**202**	**100**	**100**	**0.7**	**0.6**
Petrochem. feedstock	*120*	*121*	*117*	*119*	*120*	*117*	*17*	*22*	*0.9*	*0.9*

North America: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**4 837**	**5 268**	**5 295**	**5 621**	**5 820**	**6 039**	**6 285**	**100**	**100**	**0.7**
Coal	2 266	1 571	1 423	1 318	1 281	1 246	1 206	27	19	-0.7
Oil	227	79	71	26	22	18	12	1	0	-7.3
Gas	712	1 626	1 713	1 778	1 841	1 938	2 029	32	32	0.7
Nuclear	879	943	952	859	851	817	820	18	13	-0.6
Renewables	754	1 049	1 137	1 640	1 825	2 019	2 219	21	35	2.8
Hydro	645	662	687	754	787	808	829	13	13	0.8
Bioenergy	82	95	98	113	125	138	150	2	2	1.8
Wind	6	228	271	498	561	637	711	5	11	4.1
Geothermal	21	25	26	34	44	56	66	0	1	3.9
Solar PV	0	35	50	235	296	362	435	1	7	9.4
CSP	1	4	4	6	9	13	20	0	0	6.8
Marine	0	0	0	1	3	5	8	0	0	30.4

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**1 369**	**1 390**	**1 545**	**1 626**	**1 714**	**1 799**	**100**	**100**	**1.1**
Coal	312	302	241	233	223	212	22	12	-1.5
Oil	82	81	36	32	30	26	6	1	-4.6
Gas	516	522	602	637	678	719	38	40	1.3
Nuclear	121	121	111	109	105	105	9	6	-0.6
Renewables	338	364	555	615	679	737	26	41	3.0
Hydro	194	194	202	207	211	215	14	12	0.4
Bioenergy	22	22	25	28	30	32	2	2	1.5
Wind	87	96	167	185	203	221	7	12	3.5
Geothermal	5	5	5	7	8	9	0	1	3.1
Solar PV	29	44	153	186	220	252	3	14	7.5
CSP	2	2	2	3	4	5	0	0	4.7
Marine	0	0	0	1	2	3	0	0	21.6

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**6 477**	**5 967**	**5 819**	**5 617**	**5 432**	**5 268**	**5 157**	**100**	**100**	**-0.5**
Coal	2 324	1 595	1 456	1 324	1 281	1 237	1 188	25	23	-0.8
Oil	2 675	2 567	2 556	2 358	2 177	1 992	1 878	44	36	-1.3
Gas	1 478	1 806	1 807	1 935	1 974	2 039	2 091	31	41	0.6
Power generation	**2 690**	**2 213**	**2 104**	**1 926**	**1 889**	**1 872**	**1 844**	**100**	**100**	**-0.5**
Coal	2 144	1 469	1 331	1 204	1 166	1 127	1 082	63	59	-0.9
Oil	183	61	56	19	16	13	8	3	0	-7.5
Gas	364	683	717	703	707	732	754	34	41	0.2
TFC	**3 427**	**3 335**	**3 307**	**3 210**	**3 057**	**2 901**	**2 810**	**100**	**100**	**-0.7**
Coal	175	113	114	110	105	100	96	3	3	-0.7
Oil	2 305	2 339	2 334	2 160	1 987	1 810	1 701	71	61	-1.3
Transport	*1 926*	*2 029*	*2 033*	*1 885*	*1 733*	*1 579*	*1 491*	*61*	*53*	*-1.3*
Gas	948	882	859	940	966	992	1 013	26	36	0.7

North America: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**5 777**	**6 068**	**6 664**	**5 399**	**5 515**	**6 040**	**100**	**100**	**1.0**	**0.5**
Coal	1 433	1 421	1 375	541	162	96	21	2	-0.1	-10.6
Oil	29	27	15	22	18	8	0	0	-6.4	-8.9
Gas	1 885	2 022	2 360	2 051	1 905	1 171	35	19	1.3	-1.6
Nuclear	859	866	849	926	957	992	13	16	-0.5	0.2
Renewables	1 570	1 733	2 065	1 859	2 472	3 773	31	62	2.5	5.1
Hydro	754	787	835	760	800	854	13	14	0.8	0.9
Bioenergy	111	120	141	122	157	237	2	4	1.5	3.7
Wind	465	520	636	635	952	1 561	10	26	3.6	7.6
Geothermal	34	44	61	36	52	91	1	2	3.6	5.3
Solar PV	200	252	370	293	464	808	6	13	8.7	12.3
CSP	6	8	16	12	45	206	0	3	5.9	17.8
Marine	0	2	7	1	3	16	0	0	29.8	34.6

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**1 539**	**1 618**	**1 802**	**1 577**	**1 741**	**2 126**	**100**	**100**	**1.1**	**1.8**
Coal	247	241	233	220	143	58	13	3	-1.1	-6.7
Oil	37	35	28	29	23	14	2	1	-4.3	-7.0
Gas	624	657	760	558	577	620	42	29	1.6	0.7
Nuclear	111	111	109	119	123	128	6	6	-0.4	0.2
Renewables	521	573	673	652	874	1 306	37	61	2.6	5.5
Hydro	202	207	216	203	211	222	12	10	0.4	0.6
Bioenergy	25	27	30	27	35	52	2	2	1.2	3.6
Wind	157	172	198	215	309	476	11	22	3.0	6.9
Geothermal	5	6	9	6	8	13	0	1	2.8	4.5
Solar PV	130	158	214	196	296	477	12	22	6.8	10.4
CSP	2	3	4	4	15	60	0	3	3.7	15.9
Marine	0	1	2	0	1	6	0	0	21.0	25.7

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**5 884**	**5 844**	**5 823**	**4 685**	**3 763**	**2 394**	**100**	**100**	**0.0**	**-3.6**
Coal	1 433	1 412	1 343	601	220	85	23	4	-0.3	-11.2
Oil	2 451	2 359	2 225	2 128	1 754	1 068	38	45	-0.6	-3.6
Gas	1 999	2 073	2 256	1 956	1 790	1 242	39	52	0.9	-1.5
Power generation	**2 078**	**2 091**	**2 116**	**1 320**	**826**	**299**	**100**	**100**	**0.0**	**-7.8**
Coal	1 312	1 294	1 232	492	128	24	58	8	-0.3	-15.4
Oil	22	19	11	16	13	6	1	2	-6.6	-9.1
Gas	745	778	873	811	685	269	41	90	0.8	-4.0
TFC	**3 306**	**3 237**	**3 148**	**2 929**	**2 541**	**1 807**	**100**	**100**	**-0.2**	**-2.5**
Coal	112	108	100	100	85	55	3	3	-0.5	-3.0
Oil	2 245	2 153	2 021	1 950	1 601	968	64	54	-0.6	-3.6
Transport	*1 956*	*1 877*	*1 778*	*1 698*	*1 383*	*813*	*56*	*45*	*-0.6*	*-3.7*
Gas	950	976	1 027	880	856	784	33	43	0.7	-0.4

United States: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**2 270**	**2 183**	**2 154**	**2 188**	**2 162**	**2 132**	**2 122**	**100**	**100**	**-0.1**
Coal	534	374	336	323	316	309	299	16	14	-0.5
Oil	871	794	796	756	699	634	592	37	28	-1.2
Gas	548	646	643	688	698	715	726	30	34	0.5
Nuclear	208	216	219	200	196	187	186	10	9	-0.7
Hydro	22	22	23	25	27	28	29	1	1	1.0
Bioenergy	73	99	101	119	132	144	154	5	7	1.8
Other renewables	15	31	37	76	94	115	137	2	6	5.6
Power generation	**932**	**880**	**867**	**856**	**864**	**873**	**884**	**100**	**100**	**0.1**
Coal	502	341	307	295	289	280	269	35	30	-0.5
Oil	30	9	8	4	4	3	2	1	0	-6.1
Gas	137	242	254	240	240	246	249	29	28	-0.1
Nuclear	208	216	219	200	196	187	186	25	21	-0.7
Hydro	22	22	23	25	27	28	29	3	3	1.0
Bioenergy	21	22	23	25	27	30	33	3	4	1.5
Other renewables	13	29	34	68	82	99	117	4	13	5.3
Other energy sector	**149**	**167**	**155**	**176**	**176**	**179**	**178**	**100**	**100**	**0.6**
Electricity	*48*	*50*	*50*	*50*	*50*	*51*	*51*	*32*	*29*	*0.1*
TFC	**1 546**	**1 520**	**1 518**	**1 561**	**1 537**	**1 509**	**1 502**	**100**	**100**	**-0.0**
Coal	33	20	19	19	18	17	16	1	1	-0.8
Oil	793	758	761	724	668	609	571	50	38	-1.2
Gas	360	333	326	364	372	380	386	21	26	0.7
Electricity	301	325	325	346	357	370	384	21	26	0.7
Heat	5	5	5	5	5	4	4	0	0	-1.3
Bioenergy	52	76	78	94	105	114	121	5	8	1.8
Other renewables	2	3	3	8	12	16	20	0	1	8.2
Industry	**336**	**269**	**270**	**294**	**293**	**292**	**294**	**100**	**100**	**0.4**
Coal	30	19	19	18	17	17	16	7	5	-0.7
Oil	29	21	21	21	20	20	19	8	7	-0.3
Gas	138	127	126	142	142	140	139	47	47	0.4
Electricity	98	69	69	76	77	78	80	26	27	0.6
Heat	4	4	4	4	4	4	3	2	1	-1.0
Bioenergy	36	30	30	32	33	34	36	11	12	0.7
Other renewables	0	-	-	0	0	1	1	-	0	n.a.
Transport	**588**	**629**	**631**	**599**	**566**	**532**	**518**	**100**	**100**	**-0.8**
Oil	569	579	580	526	476	425	396	92	76	-1.6
Electricity	0	1	1	3	5	8	12	0	2	12.2
Biofuels	3	33	35	45	53	58	62	5	12	2.5
Other fuels	15	17	16	24	32	41	48	3	9	4.6
Buildings	**459**	**484**	**477**	**498**	**508**	**517**	**526**	**100**	**100**	**0.4**
Coal	2	1	1	0	0	0	0	0	0	-10.3
Oil	49	34	34	29	25	19	15	7	3	-3.4
Gas	189	182	174	181	181	181	181	37	34	0.2
Electricity	202	252	252	264	273	282	290	53	55	0.6
Heat	1	1	1	1	1	1	1	0	0	-2.3
Bioenergy	13	13	13	16	17	19	20	3	4	2.1
Traditional biomass	-	-	-	-	-	-	-	-	-	*n.a.*
Other renewables	2	3	3	8	11	15	19	1	4	7.9
Other	**163**	**138**	**140**	**170**	**170**	**167**	**164**	**100**	**100**	**0.7**
Petrochem. feedstock	*101*	*75*	*78*	*101*	*102*	*99*	*97*	*16*	*18*	*0.9*

United States: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**2 242**	**2 251**	**2 277**	**2 041**	**1 907**	**1 726**	**100**	**100**	**0.2**	**-0.9**
Coal	340	340	337	145	57	40	15	2	0.0	-8.5
Oil	780	746	678	689	581	377	30	22	-0.7	-3.1
Gas	711	729	775	719	682	537	34	31	0.8	-0.7
Nuclear	200	200	193	217	222	226	8	13	-0.5	0.1
Hydro	25	26	29	25	27	30	1	2	0.9	1.1
Bioenergy	118	129	153	150	181	214	7	12	1.7	3.2
Other renewables	67	81	112	97	157	302	5	17	4.7	9.1
Power generation	**888**	**911**	**952**	**775**	**731**	**760**	**100**	**100**	**0.4**	**-0.5**
Coal	311	312	302	119	34	19	32	3	-0.1	-10.9
Oil	4	4	2	3	3	1	0	0	-5.1	-8.2
Gas	260	268	292	299	272	164	31	22	0.6	-1.8
Nuclear	200	200	193	217	222	226	20	30	-0.5	0.1
Hydro	25	26	29	25	27	30	3	4	0.9	1.1
Bioenergy	25	27	32	26	33	49	3	6	1.4	3.2
Other renewables	62	75	102	86	139	270	11	35	4.7	9.0
Other energy sector	**182**	**184**	**192**	**165**	**157**	**133**	**100**	**100**	**0.9**	**-0.6**
Electricity	*51*	*53*	*55*	*46*	*44*	*43*	*29*	*32*	*0.4*	*-0.6*
TFC	**1 589**	**1 590**	**1 603**	**1 491**	**1 414**	**1 266**	**100**	**100**	**0.2**	**-0.8**
Coal	19	18	17	17	15	12	1	1	-0.7	-1.9
Oil	747	713	657	660	554	363	41	29	-0.6	-3.0
Gas	365	372	387	340	331	307	24	24	0.7	-0.2
Electricity	355	372	407	335	345	384	25	30	0.9	0.7
Heat	5	5	4	5	4	3	0	0	-1.1	-2.4
Bioenergy	93	102	121	123	147	165	8	13	1.8	3.1
Other renewables	5	6	10	11	17	32	1	3	5.2	10.4
Industry	**297**	**300**	**305**	**281**	**271**	**257**	**100**	**100**	**0.5**	**-0.2**
Coal	19	18	16	17	15	12	5	5	-0.6	-1.8
Oil	21	21	20	19	18	16	7	6	-0.2	-1.1
Gas	143	143	143	135	128	113	47	44	0.5	-0.5
Electricity	77	78	82	72	70	68	27	27	0.7	-0.1
Heat	4	4	3	4	4	3	1	1	-0.9	-1.7
Bioenergy	33	35	40	32	35	40	13	15	1.2	1.2
Other renewables	0	0	1	1	2	4	0	2	n.a.	n.a.
Transport	**612**	**592**	**570**	**575**	**520**	**412**	**100**	**100**	**-0.4**	**-1.8**
Oil	547	517	475	471	375	205	83	50	-0.8	-4.2
Electricity	2	2	3	7	20	60	1	15	5.8	19.9
Biofuels	44	50	61	74	93	102	11	25	2.4	4.6
Other fuels	20	24	31	23	32	45	5	11	2.8	4.4
Buildings	**510**	**528**	**563**	**469**	**458**	**438**	**100**	**100**	**0.7**	**-0.4**
Coal	0	0	0	0	0	-	0	-	-3.0	-100
Oil	31	29	21	25	19	7	4	2	-2.0	-6.3
Gas	184	187	195	164	154	132	35	30	0.5	-1.2
Electricity	274	289	320	253	253	254	57	58	1.0	0.0
Heat	1	1	1	1	1	0	0	0	-2.0	-7.9
Bioenergy	15	15	17	15	16	18	3	4	1.4	1.6
Traditional biomass	-	-	-	-	-	-	-	-	*n.a.*	*n.a.*
Other renewables	5	6	9	10	15	27	2	6	4.8	9.6
Other	**169**	**170**	**164**	**166**	**166**	**159**	**100**	**100**	**0.7**	**0.5**
Petrochem. feedstock	*101*	*101*	*96*	*100*	*100*	*95*	*17*	*22*	*0.9*	*0.9*

United States: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**4 026**	**4 292**	**4 297**	**4 546**	**4 686**	**4 835**	**5 003**	**100**	**100**	**0.6**
Coal	2 130	1 471	1 324	1 293	1 272	1 239	1 199	31	24	-0.4
Oil	118	39	33	17	17	13	8	1	0	-5.8
Gas	634	1 373	1 447	1 429	1 466	1 528	1 582	34	32	0.4
Nuclear	798	830	839	769	752	719	713	20	14	-0.7
Renewables	346	579	655	1 039	1 179	1 337	1 501	15	30	3.5
Hydro	253	251	268	290	308	322	338	6	7	1.0
Bioenergy	72	80	83	94	106	118	129	2	3	1.8
Wind	6	193	233	418	464	524	582	5	12	3.9
Geothermal	15	19	20	26	35	47	57	0	1	4.5
Solar PV	0	32	47	205	255	311	374	1	7	9.1
CSP	1	4	4	6	8	11	17	0	0	6.1
Marine	-	-	-	1	2	3	5	-	0	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**1 152**	**1 168**	**1 282**	**1 340**	**1 402**	**1 462**	**100**	**100**	**0.9**
Coal	297	287	231	227	219	209	25	14	-1.3
Oil	60	59	23	23	22	20	5	1	-4.4
Gas	466	469	525	541	565	590	40	40	1.0
Nuclear	105	105	98	95	91	90	9	6	-0.6
Renewables	224	248	405	453	505	553	21	38	3.4
Hydro	102	103	105	108	110	113	9	8	0.4
Bioenergy	18	18	20	22	24	27	2	2	1.6
Wind	73	81	138	151	165	179	7	12	3.4
Geothermal	4	4	4	5	7	8	0	1	3.5
Solar PV	26	41	136	164	194	221	3	15	7.3
CSP	2	2	2	3	3	4	0	0	3.9
Marine	-	-	0	1	1	2	-	0	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**5 602**	**4 977**	**4 837**	**4 669**	**4 491**	**4 304**	**4 163**	**100**	**100**	**-0.6**
Coal	2 172	1 465	1 329	1 272	1 245	1 203	1 155	27	28	-0.6
Oil	2 197	2 062	2 056	1 866	1 694	1 517	1 407	43	34	-1.6
Gas	1 234	1 450	1 452	1 531	1 553	1 585	1 601	30	38	0.4
Power generation	**2 433**	**1 967**	**1 855**	**1 755**	**1 733**	**1 705**	**1 664**	**100**	**100**	**-0.5**
Coal	2 014	1 371	1 234	1 180	1 158	1 120	1 075	67	65	-0.6
Oil	98	29	25	12	12	9	6	1	0	-6.1
Gas	321	568	596	563	563	575	583	32	35	-0.1
TFC	**2 909**	**2 758**	**2 738**	**2 621**	**2 468**	**2 312**	**2 219**	**100**	**100**	**-0.9**
Coal	156	86	89	85	81	77	73	3	3	-0.8
Oil	1 949	1 925	1 922	1 745	1 579	1 410	1 307	70	59	-1.6
Transport	*1 682*	*1 713*	*1 716*	*1 559*	*1 409*	*1 259*	*1 173*	*63*	*53*	*-1.6*
Gas	804	746	727	791	808	826	839	27	38	0.6

United States: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**4 676**	**4 892**	**5 317**	**4 378**	**4 464**	**4 901**	**100**	**100**	**0.9**	**0.5**
Coal	1 363	1 373	1 347	520	151	81	25	2	0.1	-11.0
Oil	19	18	10	15	13	4	0	0	-4.8	-8.0
Gas	1 552	1 642	1 868	1 773	1 660	987	35	20	1.1	-1.6
Nuclear	769	767	743	832	852	869	14	18	-0.5	0.1
Renewables	974	1 092	1 349	1 238	1 787	2 959	25	60	3.1	6.5
Hydro	289	306	333	291	315	350	6	7	0.9	1.1
Bioenergy	92	101	120	102	137	213	2	4	1.5	4.0
Wind	389	427	513	546	835	1 376	10	28	3.3	7.7
Geothermal	26	35	52	29	44	83	1	2	4.2	6.2
Solar PV	172	214	313	258	412	727	6	15	8.3	12.1
CSP	6	7	14	11	42	197	0	4	5.3	17.6
Marine	0	1	4	1	2	13	0	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**1 274**	**1 329**	**1 462**	**1 315**	**1 455**	**1 788**	**100**	**100**	**0.9**	**1.8**
Coal	232	230	226	210	137	53	15	3	-1.0	-6.8
Oil	23	23	21	16	14	8	1	0	-4.2	-7.9
Gas	547	565	631	489	500	528	43	30	1.2	0.5
Nuclear	98	97	94	105	108	111	6	6	-0.5	0.2
Renewables	373	413	490	495	696	1 088	34	61	2.9	6.4
Hydro	105	107	112	106	110	116	8	7	0.3	0.5
Bioenergy	20	21	24	22	29	45	2	3	1.3	3.9
Wind	129	139	158	182	268	416	11	23	2.8	7.1
Geothermal	4	5	8	5	7	12	1	1	3.1	5.1
Solar PV	114	137	184	176	268	436	13	24	6.5	10.4
CSP	2	2	4	4	14	58	0	3	3.0	15.7
Marine	0	1	1	0	1	5	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**4 872**	**4 809**	**4 684**	**3 824**	**2 986**	**1 761**	**100**	**100**	**-0.1**	**-4.1**
Coal	1 339	1 339	1 291	555	189	63	28	4	-0.1	-12.0
Oil	1 940	1 838	1 677	1 671	1 346	757	36	43	-0.8	-4.1
Gas	1 593	1 632	1 716	1 597	1 451	941	37	53	0.7	-1.8
Power generation	**1 870**	**1 891**	**1 900**	**1 183**	**719**	**216**	**100**	**100**	**0.1**	**-8.6**
Coal	1 246	1 249	1 208	472	119	18	64	8	-0.1	-16.2
Oil	13	13	7	11	9	3	0	2	-5.1	-8.2
Gas	610	629	685	700	590	195	36	90	0.6	-4.5
TFC	**2 699**	**2 612**	**2 486**	**2 374**	**2 025**	**1 376**	**100**	**100**	**-0.4**	**-2.8**
Coal	87	83	77	77	65	42	3	3	-0.6	-3.1
Oil	1 815	1 715	1 564	1 562	1 251	700	63	51	-0.9	-4.1
Transport	*1 619*	*1 530*	*1 407*	*1 393*	*1 109*	*606*	*57*	*44*	*-0.8*	*-4.2*
Gas	797	814	845	735	708	635	34	46	0.6	-0.6

Central and South America: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**449**	**667**	**666**	**736**	**794**	**863**	**936**	**100**	**100**	**1.4**
Coal	20	34	34	37	39	40	42	5	4	0.8
Oil	214	287	283	292	299	309	315	43	34	0.4
Gas	83	143	139	154	172	199	229	21	24	2.1
Nuclear	3	6	6	10	13	13	16	1	2	4.0
Hydro	47	58	60	76	84	93	101	9	11	2.2
Bioenergy	80	133	134	147	158	171	185	20	20	1.3
Other renewables	1	7	8	21	29	38	49	1	5	7.8
Power generation	**105**	**192**	**191**	**214**	**239**	**270**	**304**	**100**	**100**	**2.0**
Coal	7	17	18	17	18	18	19	9	6	0.2
Oil	21	36	34	22	18	17	15	18	5	-3.4
Gas	22	52	47	48	54	65	75	25	25	2.0
Nuclear	3	6	6	10	13	13	16	3	5	4.0
Hydro	47	58	60	76	84	93	101	31	33	2.2
Bioenergy	3	18	19	23	26	30	34	10	11	2.5
Other renewables	1	6	7	19	26	35	45	4	15	8.0
Other energy sector	**62**	**90**	**91**	**96**	**102**	**109**	**117**	**100**	**100**	**1.1**
Electricity	*13*	*22*	*22*	*25*	*28*	*31*	*34*	*24*	*30*	*1.9*
TFC	**352**	**495**	**496**	**562**	**606**	**656**	**707**	**100**	**100**	**1.5**
Coal	10	11	12	14	15	16	17	2	2	1.7
Oil	179	234	232	252	261	271	279	47	40	0.8
Gas	41	64	65	80	91	105	119	13	17	2.6
Electricity	56	89	90	110	125	140	157	18	22	2.4
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	66	96	96	104	112	120	129	19	18	1.2
Other renewables	0	1	1	2	2	3	4	0	1	6.5
Industry	**120**	**160**	**161**	**184**	**199**	**216**	**235**	**100**	**100**	**1.6**
Coal	10	11	11	14	15	16	17	7	7	1.7
Oil	34	35	35	36	36	36	36	22	15	0.1
Gas	20	35	36	46	53	62	71	22	30	2.9
Electricity	26	36	36	43	48	53	58	22	25	2.0
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	31	43	43	45	47	49	52	26	22	0.8
Other renewables	-	0	0	0	0	0	0	0	0	40.4
Transport	**105**	**170**	**168**	**191**	**204**	**219**	**234**	**100**	**100**	**1.4**
Oil	96	143	141	155	160	167	172	84	73	0.8
Electricity	0	0	0	1	1	2	2	0	1	7.3
Biofuels	6	20	19	27	33	38	45	11	19	3.6
Other fuels	3	8	8	8	10	12	15	5	6	2.7
Buildings	**83**	**114**	**116**	**127**	**138**	**150**	**162**	**100**	**100**	**1.4**
Coal	0	0	0	0	0	0	0	0	0	-4.3
Oil	18	20	21	21	22	23	23	18	14	0.4
Gas	9	14	14	16	18	19	21	12	13	1.8
Electricity	29	49	50	62	71	80	90	43	55	2.4
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	26	30	30	26	25	24	24	26	15	-1.0
Traditional biomass	*23*	*25*	*26*	*20*	*19*	*18*	*17*	*22*	*10*	*-1.7*
Other renewables	0	1	1	2	2	3	4	1	2	6.2
Other	**44**	**50**	**50**	**60**	**65**	**71**	**77**	**100**	**100**	**1.8**
Petrochem. feedstock	*20*	*20*	*20*	*26*	*29*	*33*	*37*	*18*	*23*	*2.5*

Central and South America: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						**Shares** (%)		**CAAGR** (%)	
	2025	**2030**	**2040**	**2025**	**2030**	**2040**	**2040**		**2016e-40**	
	Current Policies			**Sustainable Development**			**CPS**	**SDS**	**CPS**	**SDS**
TPED	**752**	**824**	**999**	**690**	**704**	**761**	**100**	**100**	**1.7**	**0.6**
Coal	40	43	49	30	24	20	5	3	1.5	-2.3
Oil	304	321	360	266	244	206	36	27	1.0	-1.3
Gas	160	184	255	140	145	153	26	20	2.5	0.4
Nuclear	9	12	14	11	13	19	1	3	3.6	4.9
Hydro	76	85	103	76	87	109	10	14	2.3	2.5
Bioenergy	143	152	177	143	154	183	18	24	1.2	1.3
Other renewables	20	26	42	23	36	71	4	9	7.1	9.5
Power generation	**222**	**252**	**324**	**196**	**205**	**256**	**100**	**100**	**2.2**	**1.2**
Coal	20	22	25	12	5	2	8	1	1.5	-9.7
Oil	23	19	17	15	8	2	5	1	-3.0	-10.4
Gas	53	63	94	38	32	23	29	9	3.0	-2.9
Nuclear	9	12	14	11	13	19	4	8	3.6	4.9
Hydro	76	85	103	76	87	109	32	42	2.3	2.5
Bioenergy	23	26	33	23	27	38	10	15	2.4	3.0
Other renewables	18	24	38	21	32	64	12	25	7.2	9.5
Other energy sector	**98**	**107**	**128**	**90**	**93**	**93**	**100**	**100**	**1.5**	**0.1**
Electricity	*26*	*30*	*37*	*24*	*25*	*30*	*29*	*33*	*2.3*	*1.4*
TFC	**571**	**626**	**752**	**532**	**547**	**589**	**100**	**100**	**1.7**	**0.7**
Coal	14	15	18	13	13	13	2	2	1.7	0.6
Oil	262	279	319	234	221	190	42	32	1.3	-0.8
Gas	80	92	121	78	87	108	16	18	2.6	2.1
Electricity	114	130	167	105	116	147	22	25	2.6	2.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	100	106	123	100	106	123	16	21	1.0	1.0
Other renewables	2	2	3	2	4	7	0	1	5.6	8.9
Industry	**186**	**203**	**244**	**174**	**178**	**189**	**100**	**100**	**1.8**	**0.7**
Coal	14	15	17	13	13	13	7	7	1.8	0.6
Oil	36	37	37	34	32	28	15	15	0.3	-0.9
Gas	46	55	74	43	46	51	30	27	3.1	1.5
Electricity	44	49	60	41	42	47	24	25	2.1	1.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	46	48	55	44	45	47	23	25	1.1	0.4
Other renewables	0	0	0	0	1	2	0	1	38.3	49.4
Transport	**194**	**212**	**256**	**184**	**187**	**190**	**100**	**100**	**1.8**	**0.5**
Oil	163	177	208	140	126	97	81	51	1.6	-1.6
Electricity	1	1	1	1	2	12	0	6	4.3	14.7
Biofuels	23	26	35	34	44	57	14	30	2.6	4.6
Other fuels	8	9	12	9	13	25	5	13	1.9	5.0
Buildings	**130**	**144**	**173**	**115**	**120**	**139**	**100**	**100**	**1.7**	**0.7**
Coal	0	0	0	0	0	0	0	0	-2.6	-8.8
Oil	22	23	25	22	22	21	14	15	0.7	0.1
Gas	16	18	22	16	18	20	13	15	2.0	1.5
Electricity	65	76	100	60	67	82	57	59	2.9	2.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	26	25	24	15	9	9	14	7	-1.0	-4.9
Traditional biomass	*20*	*19*	*17*	*10*	*4*	*4*	*10*	*3*	*-1.7*	*-7.7*
Other renewables	2	2	3	2	3	6	2	4	5.3	7.8
Other	**60**	**66**	**78**	**58**	**63**	**72**	**100**	**100**	**1.9**	**1.6**
Petrochem. feedstock	*26*	*29*	*36*	*26*	*29*	*35*	*21*	*25*	*2.4*	*2.3*

Central and South America: New Policies Scenario

	Electricity generation (TWh)							**Shares** (%)		**CAAGR** (%)
	2000	**2015**	**2016e**	**2025**	**2030**	**2035**	**2040**	**2016e**	**2040**	**2016e-40**
Total generation	**803**	**1 286**	**1 299**	**1 581**	**1 785**	**2 002**	**2 229**	**100**	**100**	**2.3**
Coal	24	73	74	75	77	80	85	6	4	0.6
Oil	104	166	159	101	84	79	71	12	3	-3.3
Gas	97	250	225	264	308	372	432	17	19	2.8
Nuclear	12	22	24	38	51	51	60	2	3	4.0
Renewables	566	775	817	1 104	1 265	1 420	1 580	63	71	2.8
Hydro	551	671	698	878	982	1 077	1 173	54	53	2.2
Bioenergy	12	67	72	87	97	110	123	6	6	2.2
Wind	0	31	41	104	131	157	186	3	8	6.6
Geothermal	2	4	4	9	13	18	25	0	1	7.9
Solar PV	0	2	3	24	37	50	63	0	3	13.8
CSP	-	-	-	2	4	7	10	-	0	n.a.
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						**Shares** (%)		**CAAGR** (%)
	2015	**2016e**	**2025**	**2030**	**2035**	**2040**	**2016e**	**2040**	**2016e-40**
Total capacity	**316**	**333**	**419**	**472**	**528**	**590**	**100**	**100**	**2.4**
Coal	12	13	17	17	18	19	4	3	1.8
Oil	47	48	41	36	35	34	14	6	-1.5
Gas	61	62	83	101	118	140	19	24	3.5
Nuclear	4	4	6	7	7	8	1	1	3.4
Renewables	192	207	272	311	349	388	62	66	2.7
Hydro	161	170	199	220	240	261	51	44	1.8
Bioenergy	18	19	23	25	27	29	6	5	1.9
Wind	11	15	32	40	47	55	4	9	5.7
Geothermal	1	1	1	2	3	4	0	1	7.4
Solar PV	2	3	15	22	29	36	1	6	11.6
CSP	-	-	1	1	2	3	-	1	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							**Shares** (%)		**CAAGR** (%)
	2000	**2015**	**2016e**	**2025**	**2030**	**2035**	**2040**	**2016e**	**2040**	**2016e-40**
Total CO_2	**829**	**1 223**	**1 207**	**1 250**	**1 303**	**1 385**	**1 464**	**100**	**100**	**0.8**
Coal	80	130	132	140	146	151	159	11	11	0.8
Oil	579	794	786	792	800	819	829	65	57	0.2
Gas	171	298	290	318	357	415	476	24	33	2.1
Power generation	**149**	**315**	**299**	**258**	**261**	**283**	**306**	**100**	**100**	**0.1**
Coal	31	80	80	77	78	79	82	27	27	0.1
Oil	67	113	109	68	56	52	47	36	15	-3.4
Gas	52	122	110	113	126	152	177	37	58	2.0
TFC	**595**	**813**	**812**	**896**	**942**	**995**	**1 043**	**100**	**100**	**1.0**
Coal	44	47	48	58	63	68	72	6	7	1.7
Oil	477	645	641	687	705	727	742	79	71	0.6
Transport	*288*	*428*	*424*	*466*	*482*	*502*	*516*	*52*	*50*	*0.8*
Gas	74	121	123	151	173	200	228	15	22	2.6

Central and South America: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**1 631**	**1 870**	**2 386**	**1 501**	**1 644**	**2 071**	**100**	**100**	**2.6**	**2.0**
Coal	88	98	117	49	22	7	5	0	2.0	-9.4
Oil	109	92	79	71	37	11	3	1	-2.9	-10.4
Gas	299	378	566	212	197	151	24	7	3.9	-1.7
Nuclear	35	46	55	43	52	74	2	4	3.6	4.9
Renewables	1 099	1 255	1 570	1 125	1 336	1 828	66	88	2.8	3.4
Hydro	880	988	1 199	885	1 010	1 263	50	61	2.3	2.5
Bioenergy	86	96	119	87	99	136	5	7	2.1	2.7
Wind	100	126	173	110	152	270	7	13	6.2	8.2
Geothermal	9	11	20	9	16	32	1	2	7.0	9.0
Solar PV	22	31	51	31	52	109	2	5	12.7	16.4
CSP	2	3	8	3	6	17	0	1	n.a.	n.a.
Marine	-	-	-	-	-	1	-	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**425**	**486**	**617**	**414**	**467**	**610**	**100**	**100**	**2.6**	**2.6**
Coal	18	20	24	15	14	9	4	2	2.7	-1.3
Oil	42	36	34	41	36	32	5	5	-1.4	-1.7
Gas	91	116	169	71	76	92	27	15	4.3	1.7
Nuclear	5	6	8	6	7	10	1	2	3.0	4.2
Renewables	270	307	383	280	334	467	62	77	2.6	3.5
Hydro	200	222	269	200	225	280	44	46	1.9	2.1
Bioenergy	23	25	29	23	26	32	5	5	1.8	2.2
Wind	31	38	51	35	48	83	8	14	5.3	7.5
Geothermal	1	2	3	2	2	5	0	1	6.4	8.5
Solar PV	14	19	29	19	31	63	5	10	10.6	14.2
CSP	1	1	2	1	2	5	0	1	n.a.	n.a.
Marine	-	-	-	-	-	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**1 313**	**1 415**	**1 685**	**1 108**	**1 010**	**853**	**100**	**100**	**1.4**	**-1.4**
Coal	153	166	189	110	80	58	11	7	1.5	-3.4
Oil	828	864	961	713	637	498	57	58	0.8	-1.9
Gas	332	385	535	286	293	297	32	35	2.6	0.1
Power generation	**288**	**308**	**384**	**188**	**123**	**68**	**100**	**100**	**1.1**	**-6.0**
Coal	91	98	111	52	22	7	29	10	1.4	-9.9
Oil	73	61	52	48	25	8	14	11	-3.0	-10.4
Gas	124	148	221	89	76	54	58	79	3.0	-2.9
TFC	**925**	**1 000**	**1 166**	**834**	**803**	**717**	**100**	**100**	**1.5**	**-0.5**
Coal	58	63	73	54	54	48	6	7	1.8	-0.0
Oil	716	761	863	632	583	467	74	65	1.2	-1.3
Transport	*491*	*531*	*624*	*420*	*380*	*290*	*54*	*40*	*1.6*	*-1.6*
Gas	151	175	230	147	166	202	20	28	2.6	2.1

Brazil: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**184**	**295**	**290**	**319**	**345**	**375**	**405**	**100**	**100**	**1.4**
Coal	13	18	17	17	17	17	17	6	4	0.1
Oil	88	118	115	121	128	134	139	40	34	0.8
Gas	8	35	30	32	37	46	54	10	13	2.4
Nuclear	2	4	4	7	8	8	10	2	3	3.5
Hydro	26	31	33	40	45	48	52	11	13	1.9
Bioenergy	47	86	87	94	101	108	116	30	29	1.2
Other renewables	0	3	3	8	11	13	16	1	4	6.7
Power generation	**37**	**74**	**71**	**79**	**88**	**99**	**111**	**100**	**100**	**1.9**
Coal	3	6	6	5	4	4	4	8	4	-1.4
Oil	4	6	5	1	1	1	1	7	1	-5.4
Gas	1	16	11	8	8	13	15	15	14	1.6
Nuclear	2	4	4	7	8	8	10	6	9	3.5
Hydro	26	31	33	40	45	48	52	46	47	1.9
Bioenergy	2	9	10	11	13	14	15	14	13	1.8
Other renewables	0	2	3	7	9	11	13	4	12	7.0
Other energy sector	**27**	**47**	**48**	**52**	**56**	**61**	**64**	**100**	**100**	**1.2**
Electricity	*6*	*11*	*11*	*12*	*14*	*15*	*16*	*23*	*26*	*1.8*
TFC	**153**	**227**	**224**	**252**	**272**	**294**	**317**	**100**	**100**	**1.4**
Coal	6	8	7	8	9	9	9	3	3	0.9
Oil	80	103	101	110	115	122	127	45	40	1.0
Gas	5	13	13	16	19	22	25	6	8	2.9
Electricity	28	42	43	51	57	64	71	19	22	2.1
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	35	61	60	65	70	75	82	27	26	1.3
Other renewables	0	1	1	1	2	2	3	0	1	5.3
Industry	**56**	**77**	**77**	**87**	**93**	**100**	**107**	**100**	**100**	**1.4**
Coal	6	8	7	8	9	9	9	9	9	0.9
Oil	14	10	10	11	11	12	12	13	11	0.5
Gas	4	9	9	13	14	17	19	12	18	2.9
Electricity	13	17	17	20	22	24	27	22	25	1.9
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	20	33	33	35	37	39	41	43	38	0.9
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Transport	**47**	**84**	**82**	**91**	**97**	**105**	**112**	**100**	**100**	**1.3**
Oil	41	64	62	67	70	73	76	76	68	0.8
Electricity	0	0	0	0	1	1	1	0	1	7.6
Biofuels	6	18	17	22	25	28	32	21	29	2.7
Other fuels	0	2	2	1	2	2	2	3	2	0.4
Buildings	**29**	**38**	**39**	**41**	**45**	**50**	**55**	**100**	**100**	**1.5**
Coal	-	-	-	-	-	-	-	-	-	n.a.
Oil	8	7	7	8	8	8	9	19	16	0.8
Gas	0	0	0	1	1	2	2	1	4	7.0
Electricity	14	23	23	28	32	36	40	60	72	2.3
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	7	7	7	3	3	2	1	18	3	-6.3
Traditional biomass	*7*	*7*	*7*	*3*	*2*	*2*	*1*	*18*	*2*	*-6.9*
Other renewables	0	1	1	1	2	2	3	2	5	5.0
Other	**21**	**27**	**27**	**33**	**36**	**39**	**42**	**100**	**100**	**1.9**
Petrochem. feedstock	*9*	*10*	*10*	*13*	*15*	*17*	*19*	*26*	*34*	*2.7*

Brazil: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**326**	**358**	**428**	**305**	**312**	**339**	**100**	**100**	**1.6**	**0.7**
Coal	18	18	19	15	12	10	4	3	0.4	-2.1
Oil	128	138	154	110	101	85	36	25	1.2	-1.3
Gas	34	41	62	28	30	38	15	11	3.0	0.9
Nuclear	7	8	10	7	8	11	2	3	3.5	3.8
Hydro	41	45	55	40	43	52	13	15	2.2	1.9
Bioenergy	91	97	112	98	107	123	26	36	1.1	1.5
Other renewables	8	10	15	8	11	20	4	6	6.4	7.6
Power generation	**83**	**95**	**122**	**73**	**78**	**100**	**100**	**100**	**2.3**	**1.5**
Coal	6	6	5	3	0	-	4	-	-0.2	-100
Oil	3	3	3	1	1	1	2	1	-2.4	-8.3
Gas	10	12	20	5	4	6	17	6	2.8	-2.7
Nuclear	7	8	10	7	8	11	8	11	3.5	3.8
Hydro	41	45	55	40	43	52	45	52	2.2	1.9
Bioenergy	11	13	15	11	12	15	12	15	1.8	1.8
Other renewables	7	9	13	7	9	16	11	16	6.9	8.0
Other energy sector	**53**	**59**	**69**	**50**	**50**	**53**	**100**	**100**	**1.5**	**0.4**
Electricity	*13*	*15*	*18*	*12*	*12*	*15*	*26*	*28*	*2.2*	*1.4*
TFC	**256**	**278**	**331**	**243**	**250**	**271**	**100**	**100**	**1.6**	**0.8**
Coal	8	9	9	8	8	7	3	3	1.0	-0.2
Oil	115	123	140	100	92	78	42	29	1.4	-1.1
Gas	16	19	26	16	18	24	8	9	3.0	2.7
Electricity	53	60	76	49	54	70	23	26	2.4	2.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	62	66	78	68	76	88	24	33	1.1	1.6
Other renewables	1	1	2	1	2	4	1	1	4.4	6.5
Industry	**88**	**95**	**112**	**84**	**85**	**89**	**100**	**100**	**1.5**	**0.6**
Coal	8	9	9	8	8	7	8	8	1.0	-0.2
Oil	11	12	12	11	10	10	11	11	0.6	-0.1
Gas	13	15	20	12	12	14	18	15	3.1	1.5
Electricity	21	23	27	19	20	22	24	25	2.0	1.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	36	38	44	34	34	36	39	40	1.2	0.4
Other renewables	0	0	0	0	0	1	0	1	n.a.	n.a.
Transport	**92**	**99**	**117**	**88**	**89**	**90**	**100**	**100**	**1.5**	**0.4**
Oil	71	76	88	59	49	32	75	35	1.4	-2.8
Electricity	0	0	1	1	2	8	1	9	4.8	15.6
Biofuels	19	21	26	27	35	44	23	49	1.8	4.0
Other fuels	1	1	2	2	3	7	2	7	-0.5	4.7
Buildings	**43**	**48**	**61**	**38**	**40**	**50**	**100**	**100**	**1.9**	**1.1**
Coal	-	-	-	-	-	-	-	-	n.a.	n.a.
Oil	8	8	9	7	7	7	15	14	1.0	-0.1
Gas	1	1	2	1	1	2	4	4	7.2	6.3
Electricity	29	34	45	27	30	37	75	74	2.9	2.0
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	3	3	1	2	1	1	2	2	-6.3	-8.8
Traditional biomass	*3*	*2*	*1*	*2*	*0*	*0*	*2*	*1*	*-6.9*	*-10.5*
Other renewables	1	1	2	1	2	3	4	6	4.1	5.6
Other	**33**	**36**	**42**	**33**	**36**	**41**	**100**	**100**	**1.9**	**1.8**
Petrochem. feedstock	*13*	*15*	*19*	*13*	*15*	*19*	*31*	*38*	*2.7*	*2.7*

Brazil: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**349**	**581**	**586**	**705**	**790**	**882**	**979**	**100**	**100**	**2.2**
Coal	11	27	25	20	20	18	18	4	2	-1.3
Oil	15	29	23	5	5	5	6	4	1	-5.5
Gas	4	79	54	46	51	76	87	9	9	2.0
Nuclear	6	15	17	26	31	31	39	3	4	3.5
Renewables	312	430	467	607	683	751	829	80	85	2.4
Hydro	304	360	383	470	518	559	608	65	62	1.9
Bioenergy	8	49	53	59	63	67	71	9	7	1.2
Wind	0	22	30	72	91	107	125	5	13	6.1
Geothermal	-	-	-	-	-	-	-	-	-	n.a.
Solar PV	-	0	0	6	11	16	21	0	2	25.9
CSP	-	-	-	-	1	2	3	-	0	n.a.
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**140**	**149**	**187**	**206**	**225**	**250**	**100**	**100**	**2.2**
Coal	4	4	5	5	4	4	3	2	-0.2
Oil	8	8	7	7	8	8	5	3	-0.0
Gas	12	12	18	18	20	23	8	9	2.8
Nuclear	2	2	3	4	4	5	1	2	4.2
Renewables	113	122	154	172	189	209	82	84	2.3
Hydro	92	97	113	122	131	142	65	57	1.6
Bioenergy	14	15	18	19	20	21	10	8	1.3
Wind	8	10	20	24	29	33	7	13	5.0
Geothermal	-	-	-	-	-	-	-	-	n.a.
Solar PV	0	0	4	7	10	12	0	5	23.3
CSP	-	-	-	0	1	1	-	0	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**292**	**451**	**427**	**438**	**462**	**497**	**523**	**100**	**100**	**0.8**
Coal	46	68	64	63	63	63	63	15	12	-0.1
Oil	229	306	298	308	320	335	345	70	66	0.6
Gas	16	77	65	67	79	100	115	15	22	2.4
Power generation	**31**	**91**	**72**	**47**	**48**	**57**	**62**	**100**	**100**	**-0.6**
Coal	17	35	31	25	24	23	22	43	35	-1.4
Oil	12	20	16	3	3	4	4	22	7	-5.4
Gas	2	36	25	18	20	30	36	35	58	1.6
TFC	**242**	**331**	**326**	**357**	**374**	**396**	**414**	**100**	**100**	**1.0**
Coal	26	31	31	34	36	37	38	9	9	0.9
Oil	206	272	267	288	298	311	321	82	78	0.8
Transport	*125*	*192*	*188*	*203*	*211*	*222*	*230*	*58*	*56*	*0.8*
Gas	10	28	28	34	40	47	55	9	13	2.8

Brazil: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**730**	**834**	**1 058**	**672**	**734**	**948**	**100**	**100**	**2.5**	**2.0**
Coal	25	24	24	13	1	-	2	-	-0.2	-100
Oil	12	12	13	3	3	3	1	0	-2.4	-8.3
Gas	59	73	120	29	27	35	11	4	3.4	-1.8
Nuclear	26	31	39	26	31	42	4	4	3.5	3.8
Renewables	608	693	862	601	672	868	82	92	2.6	2.6
Hydro	471	529	645	462	501	606	61	64	2.2	1.9
Bioenergy	59	63	71	59	62	71	7	7	1.2	1.2
Wind	71	90	123	73	95	159	12	17	6.0	7.1
Geothermal	-	-	-	-	-	-	-	-	n.a.	n.a.
Solar PV	6	11	20	7	13	32	2	3	25.8	28.2
CSP	-	1	3	-	-	-	0	-	n.a.	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**190**	**215**	**269**	**185**	**202**	**257**	**100**	**100**	**2.5**	**2.3**
Coal	5	5	5	5	5	-	2	-	0.3	-100
Oil	7	7	8	7	7	7	3	3	0.0	-0.9
Gas	20	24	32	17	17	18	12	7	4.2	1.6
Nuclear	3	4	5	3	4	5	2	2	4.2	4.3
Renewables	155	175	218	152	169	224	81	87	2.4	2.6
Hydro	113	125	153	110	117	143	57	55	1.9	1.6
Bioenergy	18	19	20	18	18	21	8	8	1.3	1.3
Wind	20	24	32	20	26	42	12	16	4.9	6.1
Geothermal	-	-	-	-	-	-	-	-	n.a.	n.a.
Solar PV	4	7	12	5	8	19	4	7	23.2	25.5
CSP	-	0	1	-	-	-	0	-	n.a.	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**468**	**507**	**594**	**383**	**338**	**279**	**100**	**100**	**1.4**	**-1.7**
Coal	68	69	71	52	35	26	12	9	0.4	-3.7
Oil	327	350	392	274	242	179	66	64	1.2	-2.1
Gas	73	89	131	57	61	74	22	27	3.0	0.6
Power generation	**62**	**67**	**86**	**30**	**14**	**15**	**100**	**100**	**0.8**	**-6.3**
Coal	31	30	29	16	2	-	34	-	-0.2	-100
Oil	8	8	9	2	2	2	10	13	-2.4	-8.3
Gas	22	28	48	11	10	13	56	87	2.8	-2.7
TFC	**370**	**397**	**454**	**324**	**296**	**240**	**100**	**100**	**1.4**	**-1.3**
Coal	34	36	39	32	31	24	9	10	1.0	-1.0
Oil	301	321	360	258	227	167	79	69	1.2	-2.0
Transport	*215*	*231*	*265*	*177*	*149*	*96*	*58*	*40*	*1.4*	*-2.8*
Gas	34	41	56	33	39	49	12	20	2.9	2.3

Europe: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**2 028**	**1 946**	**1 965**	**1 887**	**1 831**	**1 784**	**1 762**	**100**	**100**	**-0.5**
Coal	404	348	325	268	229	186	171	17	10	-2.6
Oil	712	612	622	535	488	444	410	32	23	-1.7
Gas	496	458	484	495	507	519	517	25	29	0.3
Nuclear	273	253	248	226	206	194	188	13	11	-1.2
Hydro	52	54	55	61	63	65	66	3	4	0.8
Bioenergy	79	164	169	205	219	230	241	9	14	1.5
Other renewables	11	57	61	97	120	145	169	3	10	4.3
Power generation	**837**	**836**	**834**	**810**	**795**	**787**	**796**	**100**	**100**	**-0.2**
Coal	279	253	230	179	146	109	99	28	12	-3.4
Oil	52	18	19	9	7	6	4	2	1	-5.9
Gas	154	143	161	166	178	190	190	19	24	0.7
Nuclear	273	253	248	226	206	194	188	30	24	-1.2
Hydro	52	54	55	61	63	65	66	7	8	0.8
Bioenergy	19	64	66	85	92	98	104	8	13	1.9
Other renewables	8	51	55	84	104	125	145	7	18	4.1
Other energy sector	**188**	**180**	**180**	**164**	**156**	**148**	**144**	**100**	**100**	**-0.9**
Electricity	*54*	*54*	*54*	*51*	*50*	*50*	*51*	*30*	*35*	*-0.3*
TFC	**1 396**	**1 354**	**1 378**	**1 358**	**1 335**	**1 313**	**1 299**	**100**	**100**	**-0.2**
Coal	77	56	56	51	47	43	40	4	3	-1.3
Oil	616	549	561	492	452	413	383	41	29	-1.6
Gas	313	288	294	302	302	303	301	21	23	0.1
Electricity	260	293	297	317	327	340	353	22	27	0.7
Heat	67	63	63	65	64	64	63	5	5	0.0
Bioenergy	61	98	101	118	125	130	135	7	10	1.2
Other renewables	3	6	7	12	16	20	24	0	2	5.5
Industry	**385**	**334**	**341**	**345**	**340**	**335**	**333**	**100**	**100**	**-0.1**
Coal	57	36	36	35	34	32	30	11	9	-0.8
Oil	61	39	42	39	37	34	33	12	10	-1.1
Gas	118	102	102	103	102	100	99	30	30	-0.1
Electricity	110	109	111	114	114	115	116	32	35	0.2
Heat	21	22	22	23	22	21	21	7	6	-0.3
Bioenergy	18	26	27	29	30	31	32	8	10	0.8
Other renewables	0	0	0	1	1	2	2	0	1	7.8
Transport	**345**	**371**	**379**	**354**	**340**	**325**	**315**	**100**	**100**	**-0.8**
Oil	333	345	352	312	289	266	248	93	79	-1.5
Electricity	7	7	7	11	13	18	23	2	7	5.3
Biofuels	1	14	14	23	27	28	31	4	10	3.2
Other fuels	4	6	6	9	11	13	14	2	4	3.6
Buildings	**505**	**516**	**524**	**529**	**528**	**530**	**532**	**100**	**100**	**0.1**
Coal	18	17	16	13	11	8	7	3	1	-3.3
Oil	92	57	59	39	27	17	11	11	2	-6.7
Gas	169	168	172	176	176	177	175	33	33	0.1
Electricity	138	172	174	187	194	201	208	33	39	0.7
Heat	45	40	40	41	42	42	42	8	8	0.2
Bioenergy	41	56	58	62	65	67	69	11	13	0.7
Traditional biomass	-	-	-	-	-	-	-	-	-	*n.a.*
Other renewables	2	5	5	10	14	17	20	1	4	5.7
Other	**161**	**133**	**134**	**130**	**127**	**123**	**119**	**100**	**100**	**-0.5**
Petrochem. feedstock	*88*	*72*	*71*	*67*	*64*	*61*	*59*	*14*	*11*	*-0.8*

Europe: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**1 957**	**1 947**	**1 965**	**1 786**	**1 692**	**1 562**	**100**	**100**	**0.0**	**-1.0**
Coal	301	273	244	183	131	93	12	6	-1.2	-5.1
Oil	560	533	493	493	404	265	25	17	-1.0	-3.5
Gas	520	557	606	487	456	385	31	25	0.9	-0.9
Nuclear	225	208	193	239	259	273	10	17	-1.0	0.4
Hydro	61	63	65	63	65	69	3	4	0.7	0.9
Bioenergy	199	209	230	213	232	256	12	16	1.3	1.7
Other renewables	91	105	133	109	146	221	7	14	3.3	5.5
Power generation	**847**	**853**	**889**	**760**	**755**	**775**	**100**	**100**	**0.3**	**-0.3**
Coal	210	187	166	101	58	38	19	5	-1.3	-7.2
Oil	9	7	5	8	6	2	1	0	-5.6	-8.2
Gas	178	208	244	172	152	99	27	13	1.7	-2.0
Nuclear	225	208	193	239	259	273	22	35	-1.0	0.4
Hydro	61	63	65	63	65	69	7	9	0.7	0.9
Bioenergy	83	88	98	86	94	112	11	14	1.6	2.2
Other renewables	81	93	117	92	122	183	13	24	3.2	5.2
Other energy sector	**169**	**165**	**160**	**156**	**141**	**117**	**100**	**100**	**-0.5**	**-1.8**
Electricity	*53*	*54*	*57*	*48*	*47*	*46*	*35*	*39*	*0.2*	*-0.7*
TFC	**1 401**	**1 408**	**1 432**	**1 300**	**1 230**	**1 120**	**100**	**100**	**0.2**	**-0.9**
Coal	53	50	45	48	42	31	3	3	-0.9	-2.4
Oil	516	494	461	452	373	248	32	22	-0.8	-3.3
Gas	314	321	332	288	280	265	23	24	0.5	-0.4
Electricity	329	345	380	307	315	338	27	30	1.0	0.5
Heat	66	67	68	63	61	58	5	5	0.3	-0.4
Bioenergy	114	119	130	125	136	143	9	13	1.1	1.5
Other renewables	10	12	16	17	24	38	1	3	3.8	7.5
Industry	**351**	**351**	**352**	**331**	**315**	**290**	**100**	**100**	**0.1**	**-0.7**
Coal	36	34	31	33	30	25	9	9	-0.7	-1.6
Oil	40	38	34	37	34	28	10	10	-0.9	-1.7
Gas	106	106	107	98	92	80	30	28	0.2	-1.0
Electricity	116	118	121	110	106	103	35	35	0.4	-0.3
Heat	23	23	22	22	20	18	6	6	-0.1	-0.9
Bioenergy	30	32	35	29	30	32	10	11	1.1	0.7
Other renewables	0	1	1	1	3	6	0	2	4.8	11.8
Transport	**366**	**363**	**364**	**331**	**295**	**243**	**100**	**100**	**-0.2**	**-1.8**
Oil	329	321	311	277	219	126	85	52	-0.5	-4.2
Electricity	10	11	16	13	24	48	4	20	3.6	8.6
Biofuels	20	22	28	31	39	43	8	18	2.7	4.7
Other fuels	7	8	10	9	13	25	3	10	2.4	6.2
Buildings	**554**	**566**	**594**	**510**	**496**	**472**	**100**	**100**	**0.5**	**-0.4**
Coal	14	12	11	11	8	4	2	1	-1.8	-6.1
Oil	44	35	22	37	24	6	4	1	-4.0	-8.9
Gas	187	193	201	167	161	148	34	31	0.6	-0.6
Electricity	197	210	237	178	180	182	40	38	1.3	0.2
Heat	43	44	45	40	40	40	8	8	0.5	-0.1
Bioenergy	61	62	64	62	63	63	11	13	0.5	0.4
Traditional biomass	-	-	-	-	-	-	-	-	*n.a.*	*n.a.*
Other renewables	8	10	14	14	20	30	2	6	4.1	7.6
Other	**131**	**128**	**122**	**128**	**124**	**115**	**100**	**100**	**-0.4**	**-0.6**
Petrochem. feedstock	*67*	*64*	*59*	*67*	*64*	*59*	*10*	*13*	*-0.8*	*-0.8*

Europe: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**3 650**	**4 030**	**4 080**	**4 303**	**4 407**	**4 541**	**4 693**	**100**	**100**	**0.6**
Coal	1 122	1 036	920	732	604	461	430	23	9	-3.1
Oil	208	65	66	29	22	19	13	2	0	-6.5
Gas	587	682	813	863	948	1 029	1 023	20	22	1.0
Nuclear	1 049	968	952	866	789	744	722	23	15	-1.1
Renewables	685	1 279	1 328	1 814	2 045	2 287	2 505	33	53	2.7
Hydro	607	629	638	712	734	750	765	16	16	0.8
Bioenergy	48	206	216	285	308	331	352	5	7	2.1
Wind	22	317	340	611	761	920	1 051	8	22	4.8
Geothermal	6	15	17	23	27	31	36	0	1	3.1
Solar PV	0	105	111	173	197	223	246	3	5	3.4
CSP	-	6	6	8	12	19	26	0	1	6.6
Marine	1	0	1	2	5	14	29	0	1	18.1

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**1 243**	**1 262**	**1 392**	**1 440**	**1 506**	**1 576**	**100**	**100**	**0.9**
Coal	241	234	201	167	133	122	19	8	-2.7
Oil	63	62	32	24	20	16	5	1	-5.5
Gas	263	265	294	315	347	372	21	24	1.4
Nuclear	144	144	125	112	105	101	11	6	-1.5
Renewables	531	557	740	822	899	965	44	61	2.3
Hydro	239	242	259	265	270	275	19	17	0.5
Bioenergy	42	44	58	62	65	68	4	4	1.8
Wind	147	161	258	304	348	382	13	24	3.7
Geothermal	2	2	3	4	4	5	0	0	3.1
Solar PV	98	105	159	180	199	215	8	14	3.0
CSP	2	2	3	4	6	8	0	1	5.5
Marine	0	0	1	2	6	13	0	1	17.7

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**4 500**	**3 909**	**3 903**	**3 445**	**3 183**	**2 913**	**2 750**	**100**	**100**	**-1.4**
Coal	1 568	1 350	1 250	1 016	857	680	617	32	22	-2.9
Oil	1 833	1 532	1 569	1 323	1 194	1 073	981	40	36	-1.9
Gas	1 099	1 026	1 084	1 106	1 133	1 160	1 152	28	42	0.3
Power generation	**1 692**	**1 454**	**1 403**	**1 168**	**1 049**	**918**	**866**	**100**	**100**	**-2.0**
Coal	1 163	1 062	967	750	610	454	406	69	47	-3.5
Oil	167	57	57	28	21	19	13	4	2	-5.9
Gas	363	335	379	390	418	446	446	27	52	0.7
TFC	**2 597**	**2 255**	**2 300**	**2 101**	**1 971**	**1 843**	**1 740**	**100**	**100**	**-1.2**
Coal	361	244	242	224	207	188	174	11	10	-1.4
Oil	1 541	1 376	1 410	1 213	1 099	989	906	61	52	-1.8
Transport	*998*	*1 041*	*1 064*	*940*	*871*	*802*	*745*	*46*	*43*	*-1.5*
Gas	695	635	649	664	665	667	661	28	38	0.1

Europe: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**4 468**	**4 662**	**5 082**	**4 150**	**4 220**	**4 458**	**100**	**100**	**0.9**	**0.4**
Coal	875	798	747	401	218	123	15	3	-0.9	-8.0
Oil	29	22	14	26	15	4	0	0	-6.2	-11.2
Gas	933	1 127	1 364	898	764	406	27	9	2.2	-2.8
Nuclear	864	796	742	917	992	1 048	15	24	-1.0	0.4
Renewables	1 767	1 919	2 215	1 908	2 230	2 877	44	65	2.2	3.3
Hydro	708	728	757	727	755	797	15	18	0.7	0.9
Bioenergy	279	296	331	294	326	394	7	9	1.8	2.5
Wind	584	680	862	658	860	1 248	17	28	4.0	5.6
Geothermal	22	25	29	25	33	47	1	1	2.2	4.4
Solar PV	165	178	206	194	228	295	4	7	2.6	4.2
CSP	8	10	20	10	21	53	0	1	5.5	9.8
Marine	1	3	10	2	7	43	0	1	13.0	20.1

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**1 401**	**1 451**	**1 577**	**1 405**	**1 479**	**1 651**	**100**	**100**	**0.9**	**1.1**
Coal	211	187	163	180	130	66	10	4	-1.5	-5.1
Oil	32	24	16	29	22	14	1	1	-5.4	-5.9
Gas	314	358	440	280	285	311	28	19	2.1	0.7
Nuclear	125	113	104	133	141	147	7	9	-1.4	0.1
Renewables	719	770	854	784	901	1 112	54	67	1.8	2.9
Hydro	258	263	271	264	272	285	17	17	0.5	0.7
Bioenergy	56	59	64	59	65	75	4	5	1.5	2.2
Wind	247	277	326	275	341	457	21	28	3.0	4.4
Geothermal	3	3	4	3	4	6	0	0	2.2	4.3
Solar PV	151	162	177	178	207	254	11	15	2.2	3.8
CSP	3	4	7	4	7	16	0	1	4.5	8.5
Marine	1	1	4	1	4	19	0	1	12.6	19.6

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**3 718**	**3 619**	**3 505**	**2 950**	**2 394**	**1 606**	**100**	**100**	**-0.4**	**-3.6**
Coal	1 154	1 043	919	667	443	237	26	15	-1.3	-6.7
Oil	1 398	1 327	1 229	1 198	942	541	35	34	-1.0	-4.3
Gas	1 165	1 250	1 358	1 085	1 009	828	39	52	0.9	-1.1
Power generation	**1 329**	**1 294**	**1 276**	**851**	**608**	**338**	**100**	**100**	**-0.4**	**-5.8**
Coal	882	785	688	422	235	105	54	31	-1.4	-8.8
Oil	27	21	14	25	17	7	1	2	-5.6	-8.2
Gas	419	488	574	405	356	226	45	67	1.7	-2.1
TFC	**2 205**	**2 149**	**2 064**	**1 934**	**1 650**	**1 179**	**100**	**100**	**-0.4**	**-2.7**
Coal	230	217	193	207	174	109	9	9	-0.9	-3.3
Oil	1 284	1 225	1 140	1 095	864	498	55	42	-0.9	-4.2
Transport	*992*	*967*	*935*	*835*	*659*	*378*	*45*	*32*	*-0.5*	*-4.2*
Gas	691	707	732	632	612	572	35	49	0.5	-0.5

European Union: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**1 693**	**1 584**	**1 594**	**1 485**	**1 414**	**1 350**	**1 312**	**100**	**100**	**-0.8**
Coal	321	263	239	189	152	112	94	15	7	-3.8
Oil	625	516	524	433	385	339	304	33	23	-2.2
Gas	396	358	381	379	384	385	373	24	28	-0.1
Nuclear	246	223	218	189	166	157	154	14	12	-1.4
Hydro	31	29	30	33	34	35	36	2	3	0.7
Bioenergy	67	149	154	187	199	207	216	10	16	1.4
Other renewables	7	46	48	75	94	115	135	3	10	4.4
Power generation	**683**	**668**	**664**	**626**	**601**	**584**	**583**	**100**	**100**	**-0.5**
Coal	236	197	175	130	99	64	50	26	9	-5.1
Oil	44	17	17	8	6	5	3	3	1	-6.5
Gas	103	97	116	118	127	133	127	17	22	0.4
Nuclear	246	223	218	189	166	157	154	33	26	-1.4
Hydro	31	29	30	33	34	35	36	5	6	0.7
Bioenergy	17	61	63	80	84	89	93	9	16	1.7
Other renewables	6	43	45	68	84	103	119	7	20	4.1
Other energy sector	**142**	**135**	**136**	**119**	**112**	**104**	**100**	**100**	**100**	**-1.3**
Electricity	*43*	*41*	*41*	*37*	*36*	*36*	*35*	*30*	*35*	*-0.7*
TFC	**1 180**	**1 113**	**1 130**	**1 083**	**1 046**	**1 010**	**984**	**100**	**100**	**-0.6**
Coal	52	36	35	31	28	24	22	3	2	-1.9
Oil	543	465	474	400	357	315	283	42	29	-2.1
Gas	272	241	244	243	239	236	230	22	23	-0.2
Electricity	217	236	239	250	254	260	267	21	27	0.5
Heat	45	46	46	46	45	45	44	4	4	-0.1
Bioenergy	49	88	90	106	113	117	122	8	12	1.3
Other renewables	1	3	3	7	10	13	16	0	2	7.5
Industry	**310**	**264**	**268**	**264**	**256**	**248**	**243**	**100**	**100**	**-0.4**
Coal	38	23	22	21	20	18	17	8	7	-1.1
Oil	52	32	35	31	29	27	25	13	10	-1.4
Gas	102	84	84	82	79	76	74	31	30	-0.5
Electricity	91	86	87	87	86	85	84	32	35	-0.1
Heat	11	15	15	15	14	13	12	6	5	-0.9
Bioenergy	17	24	25	28	28	29	29	9	12	0.6
Other renewables	0	0	0	0	0	1	2	0	1	18.1
Transport	**303**	**312**	**318**	**287**	**269**	**250**	**237**	**100**	**100**	**-1.2**
Oil	296	290	296	250	225	199	179	93	76	-2.1
Electricity	6	5	5	9	11	15	20	2	8	5.6
Biofuels	1	14	14	22	26	27	29	4	12	3.1
Other fuels	1	3	3	6	7	8	9	1	4	4.4
Buildings	**425**	**426**	**432**	**427**	**421**	**417**	**414**	**100**	**100**	**-0.2**
Coal	12	10	10	7	5	4	3	2	1	-5.3
Oil	81	52	53	34	24	14	9	12	2	-7.3
Gas	150	143	146	145	143	142	138	34	33	-0.2
Electricity	117	140	142	150	153	156	159	33	38	0.5
Heat	34	31	30	31	32	32	32	7	8	0.2
Bioenergy	31	47	48	53	56	58	60	11	14	0.9
Traditional biomass	-	-	-	-	-	-	-	-	-	*n.a.*
Other renewables	1	2	3	7	9	12	14	1	3	7.3
Other	**141**	**112**	**112**	**104**	**99**	**95**	**90**	**100**	**100**	**-0.9**
Petrochem. feedstock	*83*	*67*	*65*	*60*	*56*	*53*	*50*	*15*	*12*	*-1.1*

European Union: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**1 543**	**1 510**	**1 478**	**1 412**	**1 322**	**1 187**	**100**	**100**	**-0.3**	**-1.2**
Coal	213	181	136	123	90	65	9	5	-2.3	-5.3
Oil	456	424	376	399	317	189	25	16	-1.4	-4.2
Gas	401	428	456	377	345	281	31	24	0.8	-1.3
Nuclear	190	172	163	201	213	218	11	18	-1.2	-0.0
Hydro	33	34	35	33	35	37	2	3	0.7	0.8
Bioenergy	182	190	208	194	210	227	14	19	1.3	1.6
Other renewables	70	81	104	84	113	170	7	14	3.3	5.4
Power generation	**655**	**648**	**655**	**592**	**587**	**594**	**100**	**100**	**-0.1**	**-0.5**
Coal	153	126	89	70	44	31	14	5	-2.8	-6.9
Oil	8	6	4	7	5	2	1	0	-6.2	-9.0
Gas	129	154	181	128	108	65	28	11	1.9	-2.3
Nuclear	190	172	163	201	213	218	25	37	-1.2	-0.0
Hydro	33	34	35	33	35	37	5	6	0.7	0.8
Bioenergy	78	81	88	80	86	97	13	16	1.4	1.8
Other renewables	65	75	95	73	96	144	15	24	3.2	5.0
Other energy sector	**123**	**119**	**113**	**113**	**101**	**81**	**100**	**100**	**-0.8**	**-2.1**
Electricity	*39*	*39*	*40*	*35*	*34*	*33*	*36*	*40*	*-0.1*	*-1.0*
TFC	**1 120**	**1 107**	**1 095**	**1 039**	**966**	**852**	**100**	**100**	**-0.1**	**-1.2**
Coal	32	29	24	28	24	16	2	2	-1.5	-3.2
Oil	422	394	349	368	293	176	32	21	-1.3	-4.0
Gas	253	255	258	231	221	204	24	24	0.2	-0.7
Electricity	259	268	288	243	246	261	26	31	0.8	0.4
Heat	47	47	47	45	43	41	4	5	0.1	-0.5
Bioenergy	103	108	119	113	123	129	11	15	1.2	1.5
Other renewables	5	6	9	11	16	26	1	3	4.9	9.8
Industry	**269**	**265**	**258**	**253**	**237**	**212**	**100**	**100**	**-0.2**	**-1.0**
Coal	21	20	18	20	18	14	7	7	-1.0	-2.0
Oil	32	30	26	30	27	21	10	10	-1.1	-2.0
Gas	84	83	80	77	71	58	31	28	-0.2	-1.5
Electricity	89	89	89	84	80	76	34	36	0.1	-0.6
Heat	15	14	13	14	13	10	5	5	-0.7	-1.6
Bioenergy	28	29	32	27	28	29	12	14	0.9	0.5
Other renewables	0	0	1	1	2	4	0	2	13.8	22.6
Transport	**298**	**289**	**278**	**269**	**234**	**182**	**100**	**100**	**-0.6**	**-2.3**
Oil	266	253	232	222	167	82	83	45	-1.0	-5.2
Electricity	8	10	13	12	21	42	5	23	3.7	8.8
Biofuels	19	21	27	30	37	38	10	21	2.7	4.3
Other fuels	4	5	6	6	9	20	2	11	2.9	7.9
Buildings	**448**	**453**	**467**	**414**	**398**	**372**	**100**	**100**	**0.3**	**-0.6**
Coal	8	6	4	6	3	0	1	0	-3.7	-21.0
Oil	39	31	19	33	21	5	4	1	-4.2	-9.0
Gas	154	158	162	138	131	117	35	31	0.4	-0.9
Electricity	158	166	183	143	142	141	39	38	1.1	-0.1
Heat	32	33	34	31	31	30	7	8	0.5	0.0
Bioenergy	52	54	57	53	55	57	12	15	0.7	0.7
Traditional biomass	-	-	-	-	-	-	-	-	*n.a.*	*n.a.*
Other renewables	5	6	8	10	14	22	2	6	4.8	9.4
Other	**105**	**100**	**92**	**103**	**97**	**86**	**100**	**100**	**-0.8**	**-1.1**
Petrochem. feedstock	*59*	*56*	*49*	*59*	*56*	*50*	*11*	*13*	*-1.2*	*-1.1*

European Union: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**3 004**	**3 200**	**3 244**	**3 341**	**3 372**	**3 429**	**3 505**	**100**	**100**	**0.3**
Coal	968	826	713	537	409	259	207	22	6	-5.0
Oil	181	61	62	27	20	17	11	2	0	-7.1
Gas	480	497	633	660	724	764	726	20	21	0.6
Nuclear	945	857	838	726	638	602	592	26	17	-1.4
Renewables	431	959	998	1 390	1 581	1 787	1 969	31	56	2.9
Hydro	357	341	348	382	395	405	413	11	12	0.7
Bioenergy	46	201	211	273	289	305	318	6	9	1.7
Wind	22	302	320	562	693	835	951	10	27	4.6
Geothermal	5	7	7	8	11	13	16	0	0	3.8
Solar PV	0	102	107	157	178	200	220	3	6	3.1
CSP	-	6	6	7	10	16	22	0	1	5.9
Marine	1	0	1	2	5	14	29	0	1	18.1

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**1 013**	**1 025**	**1 112**	**1 141**	**1 188**	**1 236**	**100**	**100**	**0.8**
Coal	185	176	142	109	76	63	17	5	-4.2
Oil	52	51	26	19	16	12	5	1	-6.0
Gas	216	216	235	250	272	283	21	23	1.1
Nuclear	127	127	106	91	85	84	12	7	-1.7
Renewables	433	455	604	673	738	794	44	64	2.3
Hydro	152	153	160	164	167	170	15	14	0.4
Bioenergy	41	43	55	58	60	62	4	5	1.5
Wind	141	154	239	279	317	345	15	28	3.4
Geothermal	1	1	1	1	2	2	0	0	3.8
Solar PV	95	101	145	164	180	194	10	16	2.8
CSP	2	2	3	4	6	7	0	1	4.9
Marine	0	0	1	2	6	13	0	1	17.7

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**3 758**	**3 142**	**3 121**	**2 653**	**2 384**	**2 093**	**1 900**	**100**	**100**	**-2.0**
Coal	1 275	1 033	933	722	574	405	334	30	18	-4.2
Oil	1 607	1 306	1 335	1 081	947	821	726	43	38	-2.5
Gas	875	803	854	851	863	867	840	27	44	-0.1
Power generation	**1 379**	**1 124**	**1 072**	**857**	**739**	**597**	**521**	**100**	**100**	**-3.0**
Coal	997	843	748	555	423	270	211	70	41	-5.1
Oil	140	52	52	24	18	16	10	5	2	-6.5
Gas	242	229	272	277	299	312	299	25	57	0.4
TFC	**2 198**	**1 856**	**1 886**	**1 660**	**1 519**	**1 382**	**1 274**	**100**	**100**	**-1.6**
Coal	240	154	151	134	120	106	96	8	8	-1.9
Oil	1 355	1 167	1 193	987	866	751	665	63	52	-2.4
Transport	*889*	*879*	*897*	*759*	*681*	*604*	*543*	*48*	*43*	*-2.1*
Gas	602	535	542	540	532	525	513	29	40	-0.2

European Union: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**3 471**	**3 574**	**3 809**	**3 233**	**3 258**	**3 394**	**100**	**100**	**0.7**	**0.2**
Coal	644	533	393	279	162	100	10	3	-2.5	-7.9
Oil	27	20	12	24	14	3	0	0	-6.7	-12.4
Gas	721	887	1 067	711	577	276	28	8	2.2	-3.4
Nuclear	728	662	626	772	817	837	16	25	-1.2	-0.0
Renewables	1 352	1 472	1 713	1 447	1 689	2 179	45	64	2.3	3.3
Hydro	381	392	408	387	403	425	11	13	0.7	0.8
Bioenergy	266	279	303	280	303	348	8	10	1.5	2.1
Wind	539	622	780	588	744	1 043	20	31	3.8	5.0
Geothermal	7	9	12	9	15	25	0	1	2.6	5.8
Solar PV	149	160	183	173	199	250	5	7	2.3	3.6
CSP	7	8	17	8	18	45	0	1	4.8	9.0
Marine	1	3	10	2	7	43	0	1	12.9	20.1

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**1 115**	**1 145**	**1 228**	**1 120**	**1 172**	**1 284**	**100**	**100**	**0.8**	**0.9**
Coal	147	116	79	133	97	52	6	4	-3.3	-5.0
Oil	26	19	12	23	18	11	1	1	-5.9	-6.3
Gas	251	289	355	220	221	223	29	17	2.1	0.1
Nuclear	105	94	88	112	117	118	7	9	-1.5	-0.3
Renewables	585	626	694	632	719	880	57	69	1.8	2.8
Hydro	159	163	168	162	167	175	14	14	0.4	0.5
Bioenergy	54	56	59	57	61	67	5	5	1.3	1.9
Wind	230	255	297	248	296	382	24	30	2.8	3.9
Geothermal	1	1	2	1	2	3	0	0	2.6	5.8
Solar PV	137	146	159	161	183	219	13	17	1.9	3.3
CSP	3	3	6	3	6	14	0	1	3.9	7.9
Marine	1	1	4	1	4	19	0	1	12.7	19.6

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**2 875**	**2 725**	**2 481**	**2 274**	**1 816**	**1 139**	**100**	**100**	**-1.0**	**-4.1**
Coal	824	693	509	448	303	153	21	13	-2.5	-7.3
Oil	1 149	1 065	938	979	742	374	38	33	-1.5	-5.2
Gas	902	966	1 034	847	771	612	42	54	0.8	-1.4
Power generation	**981**	**916**	**811**	**619**	**447**	**232**	**100**	**100**	**-1.2**	**-6.2**
Coal	654	536	376	296	179	80	46	35	-2.8	-8.9
Oil	24	18	11	22	15	5	1	2	-6.2	-9.0
Gas	303	362	424	301	254	146	52	63	1.9	-2.6
TFC	**1 752**	**1 674**	**1 547**	**1 527**	**1 263**	**842**	**100**	**100**	**-0.8**	**-3.3**
Coal	137	126	106	122	98	54	7	6	-1.4	-4.2
Oil	1 051	978	864	891	675	340	56	40	-1.3	-5.1
Transport	*807*	*767*	*704*	*673*	*508*	*250*	*46*	*30*	*-1.0*	*-5.2*
Gas	563	569	576	514	490	448	37	53	0.3	-0.8

Africa: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**501**	**786**	**804**	**953**	**1 056**	**1 166**	**1 289**	**100**	**100**	**2.0**
Coal	90	108	106	112	117	125	141	13	11	1.2
Oil	104	178	184	214	236	259	285	23	22	1.8
Gas	47	107	111	146	174	207	252	14	20	3.5
Nuclear	3	3	3	4	7	10	12	0	1	6.2
Hydro	6	10	11	19	25	32	38	1	3	5.4
Bioenergy	250	374	384	441	461	469	462	48	36	0.8
Other renewables	0	5	6	18	36	64	100	1	8	12.7
Power generation	**98**	**174**	**177**	**208**	**247**	**299**	**368**	**100**	**100**	**3.1**
Coal	52	70	69	70	69	66	66	39	18	-0.2
Oil	13	28	30	23	22	23	21	17	6	-1.5
Gas	22	57	59	72	85	100	127	33	35	3.2
Nuclear	3	3	3	4	7	10	12	2	3	6.2
Hydro	6	10	11	19	25	32	38	6	10	5.4
Bioenergy	1	1	1	3	5	8	11	1	3	10.2
Other renewables	0	5	5	17	33	60	94	3	26	12.6
Other energy sector	**74**	**109**	**113**	**149**	**164**	**177**	**188**	**100**	**100**	**2.1**
Electricity	*8*	*15*	*15*	*19*	*23*	*27*	*33*	*13*	*17*	*3.3*
TFC	**369**	**571**	**584**	**690**	**761**	**834**	**912**	**100**	**100**	**1.9**
Coal	19	21	20	22	24	27	34	3	4	2.2
Oil	89	150	154	186	209	231	258	26	28	2.2
Gas	14	34	35	53	68	83	98	6	11	4.4
Electricity	31	54	55	75	93	117	145	10	16	4.1
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	216	312	319	353	365	372	370	55	41	0.6
Other renewables	0	0	0	1	2	4	6	0	1	15.8
Industry	**57**	**91**	**92**	**115**	**132**	**154**	**183**	**100**	**100**	**2.9**
Coal	11	14	14	17	19	23	30	15	16	3.3
Oil	13	16	16	19	21	23	26	17	14	2.0
Gas	6	19	20	27	31	37	44	21	24	3.4
Electricity	15	22	22	28	32	37	44	24	24	2.9
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	13	20	21	24	28	34	40	22	22	2.7
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Transport	**52**	**98**	**100**	**122**	**137**	**150**	**166**	**100**	**100**	**2.1**
Oil	51	96	98	119	134	146	160	98	97	2.1
Electricity	1	0	0	1	1	1	1	0	1	4.0
Biofuels	-	0	0	0	1	1	1	0	1	16.3
Other fuels	1	1	1	2	2	3	4	1	2	5.0
Buildings	**240**	**359**	**368**	**422**	**457**	**492**	**522**	**100**	**100**	**1.5**
Coal	2	5	5	4	3	2	2	1	0	-3.3
Oil	17	24	25	29	33	40	48	7	9	2.8
Gas	4	11	11	19	28	37	44	3	8	5.8
Electricity	15	30	31	44	58	75	96	8	18	4.8
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	202	288	295	325	333	334	326	80	62	0.4
Traditional biomass	*197*	*280*	*287*	*315*	*321*	*320*	*309*	*78*	*59*	*0.3*
Other renewables	0	0	0	1	2	4	6	0	1	15.4
Other	**20**	**24**	**24**	**31**	**35**	**38**	**41**	**100**	**100**	**2.3**
Petrochem. feedstock	*11*	*7*	*8*	*12*	*14*	*16*	*18*	*2*	*4*	*3.7*

Africa: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**968**	**1 089**	**1 358**	**722**	**677**	**848**	**100**	**100**	**2.2**	**0.2**
Coal	118	132	179	95	87	80	13	9	2.2	-1.1
Oil	221	250	320	200	211	223	24	26	2.3	0.8
Gas	149	183	266	129	136	155	20	18	3.7	1.4
Nuclear	4	7	11	4	7	19	1	2	5.9	8.2
Hydro	17	21	30	19	24	38	2	5	4.4	5.5
Bioenergy	444	468	484	246	144	152	36	18	1.0	-3.8
Other renewables	16	28	68	29	68	181	5	21	10.9	15.5
Power generation	**212**	**254**	**367**	**185**	**211**	**310**	**100**	**100**	**3.1**	**2.4**
Coal	76	81	94	55	42	17	25	6	1.3	-5.6
Oil	23	22	20	20	16	9	6	3	-1.5	-4.8
Gas	75	92	140	58	51	44	38	14	3.7	-1.2
Nuclear	4	7	11	4	7	19	3	6	5.9	8.2
Hydro	17	21	30	19	24	38	8	12	4.4	5.5
Bioenergy	2	5	9	3	6	13	3	4	9.5	11.1
Other renewables	15	26	62	27	63	170	17	55	10.6	15.4
Other energy sector	**152**	**173**	**214**	**87**	**78**	**99**	**100**	**100**	**2.7**	**-0.5**
Electricity	*19*	*23*	*33*	*18*	*21*	*29*	*16*	*29*	*3.4*	*2.8*
TFC	**699**	**778**	**947**	**541**	**505**	**617**	**100**	**100**	**2.0**	**0.2**
Coal	23	25	37	21	21	28	4	5	2.6	1.3
Oil	193	223	294	178	193	213	31	35	2.7	1.4
Gas	53	67	96	51	63	89	10	14	4.3	3.9
Electricity	75	92	137	74	95	150	14	24	3.8	4.2
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	355	368	378	216	127	127	40	21	0.7	-3.8
Other renewables	1	2	6	2	4	11	1	2	15.2	18.4
Industry	**117**	**136**	**190**	**110**	**121**	**155**	**100**	**100**	**3.1**	**2.2**
Coal	17	20	32	16	17	24	17	16	3.6	2.5
Oil	20	22	27	19	20	22	14	14	2.2	1.4
Gas	27	31	43	26	29	38	22	24	3.3	2.7
Electricity	28	33	45	26	28	36	24	23	3.0	2.0
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	25	30	43	24	26	34	23	22	3.1	2.1
Other renewables	0	0	0	0	0	1	0	1	n.a.	n.a.
Transport	**127**	**147**	**191**	**116**	**126**	**137**	**100**	**100**	**2.7**	**1.3**
Oil	124	144	186	112	119	121	98	88	2.7	0.9
Electricity	1	1	1	1	1	2	1	1	3.0	5.3
Biofuels	0	0	1	2	3	6	0	4	15.0	24.8
Other fuels	2	2	3	2	3	9	1	7	3.8	9.1
Buildings	**423**	**459**	**523**	**284**	**223**	**285**	**100**	**100**	**1.5**	**-1.1**
Coal	4	4	3	4	3	2	1	1	-1.8	-4.5
Oil	30	36	55	30	34	47	11	17	3.4	2.7
Gas	19	28	43	18	24	35	8	12	5.8	4.8
Electricity	44	55	87	45	64	109	17	38	4.4	5.4
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	326	334	330	187	95	83	63	29	0.5	-5.1
Traditional biomass	*315*	*321*	*309*	*176*	*81*	*66*	*59*	*23*	*0.3*	*-6.0*
Other renewables	1	2	5	2	4	9	1	3	14.9	17.6
Other	**32**	**36**	**43**	**31**	**34**	**40**	**100**	**100**	**2.5**	**2.1**
Petrochem. feedstock	*12*	*14*	*18*	*12*	*14*	*18*	*3*	*6*	*3.7*	*3.7*

Africa: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**449**	**795**	**814**	**1 094**	**1 349**	**1 671**	**2 069**	**100**	**100**	**4.0**
Coal	209	257	251	281	285	287	294	31	14	0.7
Oil	59	104	111	92	90	92	86	14	4	-1.1
Gas	92	285	296	387	465	562	735	36	36	3.9
Nuclear	13	12	11	14	26	39	46	1	2	6.2
Renewables	77	137	145	321	482	691	909	18	44	8.0
Hydro	75	121	124	220	293	371	436	15	21	5.4
Bioenergy	1	2	2	10	20	30	40	0	2	13.3
Wind	0	8	11	30	43	55	69	1	3	7.9
Geothermal	0	4	5	11	22	40	64	1	3	11.2
Solar PV	0	3	3	43	90	165	244	0	12	20.1
CSP	-	0	0	7	15	30	56	0	3	45.3
Marine	-	-	-	-	-	-	0	-	0	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**197**	**207**	**327**	**411**	**516**	**632**	**100**	**100**	**4.8**
Coal	45	45	55	57	60	62	22	10	1.4
Oil	37	39	38	38	40	39	19	6	-0.0
Gas	79	82	136	165	195	237	39	37	4.5
Nuclear	2	2	2	4	5	7	1	1	5.2
Renewables	35	40	95	147	216	287	19	45	8.6
Hydro	28	32	54	71	89	104	15	16	5.1
Bioenergy	1	1	3	5	7	9	0	1	11.9
Wind	3	4	12	16	20	24	2	4	8.0
Geothermal	1	1	2	3	6	10	0	2	11.9
Solar PV	2	2	23	47	85	124	1	20	17.8
CSP	0	0	3	5	10	16	0	3	16.5
Marine	-	-	-	-	-	0	-	0	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**659**	**1 141**	**1 164**	**1 321**	**1 447**	**1 586**	**1 782**	**100**	**100**	**1.8**
Coal	262	397	387	401	405	409	437	33	25	0.5
Oil	299	521	541	613	674	738	808	47	45	1.7
Gas	98	223	236	307	368	440	537	20	30	3.5
Power generation	**299**	**497**	**503**	**520**	**541**	**568**	**623**	**100**	**100**	**0.9**
Coal	206	276	271	278	274	263	261	54	42	-0.2
Oil	41	87	92	72	68	70	63	18	10	-1.6
Gas	52	134	139	169	199	235	299	28	48	3.2
TFC	**323**	**561**	**573**	**696**	**796**	**898**	**1 024**	**100**	**100**	**2.5**
Coal	55	79	77	84	91	103	125	14	12	2.0
Oil	245	424	431	514	577	636	711	75	69	2.1
Transport	*149*	*286*	*293*	*354*	*397*	*432*	*475*	*51*	*46*	*2.0*
Gas	23	58	65	98	129	160	188	11	18	4.6

Africa: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**1 093**	**1 335**	**1 964**	**1 064**	**1 350**	**2 070**	**100**	**100**	**3.7**	**4.0**
Coal	300	328	402	217	171	66	20	3	2.0	-5.4
Oil	91	89	85	80	64	36	4	2	-1.1	-4.6
Gas	404	509	799	338	329	286	41	14	4.2	-0.1
Nuclear	14	27	43	14	28	71	2	3	5.9	8.2
Renewables	282	382	635	415	759	1 611	32	78	6.4	10.6
Hydro	197	244	352	221	282	447	18	22	4.4	5.5
Bioenergy	9	17	34	11	22	48	2	2	12.5	14.2
Wind	28	37	58	50	86	147	3	7	7.2	11.4
Geothermal	11	18	47	12	25	74	2	4	9.8	11.9
Solar PV	34	57	112	106	306	764	6	37	16.3	26.0
CSP	5	9	33	15	38	130	2	6	42.1	50.5
Marine	-	-	0	0	0	1	0	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**319**	**386**	**539**	**351**	**475**	**751**	**100**	**100**	**4.1**	**5.5**
Coal	58	64	81	50	45	33	15	4	2.5	-1.3
Oil	38	38	39	36	33	29	7	4	-0.0	-1.2
Gas	140	170	233	129	135	138	43	18	4.5	2.2
Nuclear	2	4	6	2	4	10	1	1	4.7	7.2
Renewables	81	110	181	135	257	541	33	72	6.5	11.5
Hydro	47	58	84	53	68	108	16	14	4.1	5.3
Bioenergy	2	4	8	3	5	10	1	1	11.2	12.7
Wind	11	14	20	19	32	51	4	7	7.2	11.4
Geothermal	2	3	7	2	4	11	1	1	10.5	12.6
Solar PV	17	27	52	52	135	322	10	43	13.6	22.5
CSP	2	3	10	5	13	37	2	5	14.0	20.5
Marine	-	-	0	0	0	0	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**1 374**	**1 564**	**2 051**	**1 177**	**1 159**	**1 113**	**100**	**100**	**2.4**	**-0.2**
Coal	426	457	562	333	281	181	27	16	1.6	-3.1
Oil	634	719	919	574	598	620	45	56	2.2	0.6
Gas	314	388	571	269	280	311	28	28	3.8	1.2
Power generation	**548**	**604**	**762**	**414**	**333**	**171**	**100**	**100**	**1.7**	**-4.4**
Coal	300	320	371	216	162	40	49	24	1.3	-7.6
Oil	72	68	63	63	50	28	8	16	-1.6	-4.9
Gas	176	216	329	135	121	103	43	60	3.7	-1.3
TFC	**720**	**845**	**1 142**	**664**	**727**	**838**	**100**	**100**	**2.9**	**1.6**
Coal	87	97	139	79	80	94	12	11	2.5	0.8
Oil	535	621	818	492	530	576	72	69	2.7	1.2
Transport	*369*	*429*	*552*	*333*	*354*	*358*	*48*	*43*	*2.7*	*0.8*
Gas	98	128	185	94	118	168	16	20	4.5	4.1

South Africa: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**111**	**142**	**139**	**143**	**147**	**151**	**157**	**100**	**100**	**0.5**
Coal	82	97	94	91	86	82	79	67	51	-0.7
Oil	12	22	22	25	27	29	31	16	20	1.4
Gas	1	3	3	4	5	6	8	2	5	3.8
Nuclear	3	3	3	4	7	10	12	2	8	6.2
Hydro	0	0	0	0	0	0	0	0	0	7.4
Bioenergy	13	16	16	16	16	17	16	11	11	0.1
Other renewables	-	0	1	3	5	7	9	1	6	11.1
Power generation	**51**	**65**	**64**	**64**	**66**	**68**	**71**	**100**	**100**	**0.5**
Coal	48	62	60	56	51	46	43	94	60	-1.4
Oil	-	0	0	0	0	0	0	0	0	6.8
Gas	-	-	-	1	1	2	4	-	5	n.a.
Nuclear	3	3	3	4	7	10	12	4	17	6.2
Hydro	0	0	0	0	0	0	0	0	0	7.4
Bioenergy	0	0	0	1	2	3	4	0	6	16.7
Other renewables	-	0	1	2	4	6	8	1	11	11.5
Other energy sector	**23**	**23**	**23**	**25**	**26**	**27**	**28**	**100**	**100**	**0.8**
Electricity	*4*	*4*	*4*	*4*	*4*	*5*	*5*	*17*	*18*	*1.0*
TFC	**56**	**75**	**74**	**78**	**82**	**86**	**91**	**100**	**100**	**0.9**
Coal	16	18	17	16	16	15	15	23	16	-0.6
Oil	16	26	26	29	31	33	35	35	39	1.2
Gas	-	2	2	2	2	3	3	2	3	2.0
Electricity	15	17	17	20	22	25	28	23	31	2.1
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	9	12	12	11	11	10	9	16	10	-1.1
Other renewables	-	0	0	0	1	1	1	0	1	9.5
Industry	**20**	**27**	**26**	**28**	**29**	**30**	**32**	**100**	**100**	**0.8**
Coal	9	11	11	11	11	11	11	40	35	0.2
Oil	1	2	2	1	1	2	2	6	5	-0.2
Gas	-	2	2	2	2	2	3	7	8	1.6
Electricity	8	10	10	11	12	13	13	39	42	1.1
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	2	2	2	2	2	3	3	8	9	1.4
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Transport	**12**	**18**	**18**	**22**	**24**	**26**	**29**	**100**	**100**	**1.9**
Oil	12	18	18	21	23	25	27	98	94	1.7
Electricity	0	0	0	0	0	1	1	2	2	3.6
Biofuels	-	-	-	0	0	1	1	-	3	n.a.
Other fuels	-	0	0	0	0	0	0	0	0	32.7
Buildings	**16**	**22**	**22**	**21**	**21**	**22**	**22**	**100**	**100**	**0.1**
Coal	2	5	5	4	3	2	2	23	9	-3.7
Oil	1	1	1	1	1	1	1	6	4	-1.7
Gas	-	0	0	0	0	0	0	0	1	22.4
Electricity	6	6	6	7	9	11	13	26	58	3.5
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	8	10	10	9	8	7	5	45	23	-2.6
Traditional biomass	*8*	*10*	*10*	*8*	*7*	*6*	*4*	*45*	*20*	*-3.2*
Other renewables	-	0	0	0	1	1	1	1	5	8.9
Other	**7**	**7**	**7**	**8**	**8**	**8**	**8**	**100**	**100**	**0.4**
Petrochem. feedstock	*5*	*3*	*3*	*3*	*3*	*3*	*4*	*13*	*16*	*1.1*

South Africa: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**148**	**155**	**172**	**129**	**120**	**121**	**100**	**100**	**0.9**	**-0.6**
Coal	95	94	95	79	64	40	55	33	0.0	-3.5
Oil	26	29	35	24	24	23	20	19	1.9	0.2
Gas	4	5	8	5	6	10	5	9	3.7	4.8
Nuclear	4	7	11	4	7	14	7	12	5.9	6.9
Hydro	0	0	0	0	0	0	0	0	7.4	8.3
Bioenergy	16	16	16	12	10	15	9	12	0.0	-0.3
Other renewables	2	4	7	5	9	18	4	15	9.7	14.2
Power generation	**68**	**72**	**82**	**56**	**51**	**48**	**100**	**100**	**1.0**	**-1.2**
Coal	60	58	56	45	31	8	69	16	-0.3	-8.2
Oil	0	0	0	0	0	0	0	0	7.4	5.4
Gas	1	2	3	1	2	6	4	12	n.a.	n.a.
Nuclear	4	7	11	4	7	14	14	29	5.9	6.9
Hydro	0	0	0	0	0	0	0	1	7.4	8.3
Bioenergy	1	2	4	1	2	5	5	10	16.8	17.3
Other renewables	2	3	6	4	8	16	7	33	10.0	14.6
Other energy sector	**25**	**26**	**28**	**23**	**23**	**25**	**100**	**100**	**0.9**	**0.5**
Electricity	*4*	*5*	*6*	*4*	*4*	*4*	*20*	*14*	*1.5*	*-0.4*
TFC	**80**	**85**	**98**	**72**	**69**	**74**	**100**	**100**	**1.2**	**0.0**
Coal	17	17	17	15	14	11	17	16	-0.1	-1.7
Oil	30	32	39	27	28	27	40	37	1.7	0.2
Gas	2	2	3	2	2	3	3	4	1.8	2.4
Electricity	21	23	30	18	19	23	31	31	2.4	1.3
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	11	10	9	8	5	7	9	10	-1.3	-2.1
Other renewables	0	0	1	1	1	2	1	3	8.0	11.9
Industry	**29**	**30**	**33**	**26**	**26**	**26**	**100**	**100**	**1.0**	**-0.1**
Coal	11	12	12	10	10	8	37	33	0.6	-1.0
Oil	2	2	2	1	1	1	5	5	-0.2	-0.7
Gas	2	2	3	2	2	2	8	9	1.6	1.1
Electricity	12	12	14	11	10	10	42	40	1.3	0.0
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	2	2	3	2	2	3	9	12	1.5	1.6
Other renewables	0	0	0	0	0	0	0	1	n.a.	n.a.
Transport	**22**	**25**	**32**	**21**	**22**	**24**	**100**	**100**	**2.4**	**1.1**
Oil	22	24	31	20	20	20	96	84	2.3	0.4
Electricity	0	0	1	0	0	1	2	5	2.7	6.0
Biofuels	0	0	1	1	1	2	2	9	n.a.	n.a.
Other fuels	0	0	0	0	0	1	0	3	18.4	43.9
Buildings	**22**	**22**	**24**	**17**	**14**	**17**	**100**	**100**	**0.5**	**-1.1**
Coal	4	4	3	3	3	1	12	9	-2.1	-4.9
Oil	1	1	1	1	1	1	4	4	-0.8	-2.2
Gas	0	0	0	0	0	0	1	1	20.3	22.4
Electricity	8	10	14	7	8	11	59	63	3.9	2.6
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	9	8	5	5	2	2	21	13	-2.7	-6.2
Traditional biomass	*8*	*7*	*4*	*5*	*1*	*1*	*18*	*9*	*-3.2*	*-7.7*
Other renewables	0	0	1	1	1	2	3	10	7.8	10.9
Other	**8**	**8**	**8**	**8**	**8**	**8**	**100**	**100**	**0.6**	**0.3**
Petrochem. feedstock	*3*	*3*	*4*	*3*	*3*	*4*	*15*	*21*	*1.1*	*1.1*

South Africa: New Policies Scenario

	Electricity generation (TWh)							**Shares** (%)		**CAAGR** (%)
	2000	**2015**	**2016e**	**2025**	**2030**	**2035**	**2040**	**2016e**	**2040**	**2016e-40**
Total generation	**208**	**247**	**242**	**274**	**299**	**329**	**360**	**100**	**100**	**1.7**
Coal	193	229	224	228	216	208	201	92	56	-0.4
Oil	-	0	0	0	0	1	1	0	0	6.3
Gas	-	-	-	5	10	15	24	-	7	n.a.
Nuclear	13	12	11	14	26	39	46	4	13	6.2
Renewables	1	6	8	26	46	67	89	3	25	10.6
Hydro	1	1	1	1	2	3	4	0	1	7.4
Bioenergy	0	0	0	4	8	12	16	0	4	17.8
Wind	-	2	4	10	15	20	26	2	7	7.7
Geothermal	-	-	-	0	0	0	0	-	0	n.a.
Solar PV	-	2	2	8	15	22	29	1	8	10.7
CSP	-	-	-	3	6	10	14	-	4	n.a.
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						**Shares** (%)		**CAAGR** (%)
	2015	**2016e**	**2025**	**2030**	**2035**	**2040**	**2016e**	**2040**	**2016e-40**
Total capacity	**50**	**52**	**68**	**78**	**89**	**100**	**100**	**100**	**2.7**
Coal	39	39	45	44	45	45	75	45	0.6
Oil	3	4	3	3	3	3	7	3	-0.6
Gas	-	-	3	5	7	10	-	10	n.a.
Nuclear	2	2	2	4	5	7	4	7	5.2
Renewables	5	7	15	22	28	35	12	35	7.3
Hydro	2	3	4	4	4	5	6	5	1.5
Bioenergy	0	0	1	2	3	4	0	4	11.9
Wind	1	1	4	5	7	8	3	8	7.3
Geothermal	-	-	0	0	0	0	-	0	n.a.
Solar PV	1	1	5	8	11	14	3	14	9.9
CSP	-	-	1	2	3	4	-	4	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							**Shares** (%)		**CAAGR** (%)
	2000	**2015**	**2016e**	**2025**	**2030**	**2035**	**2040**	**2016e**	**2040**	**2016e-40**
Total CO_2	**281**	**427**	**417**	**408**	**392**	**378**	**374**	**100**	**100**	**-0.5**
Coal	231	352	341	321	299	277	262	82	70	-1.1
Oil	49	71	72	79	85	90	97	17	26	1.2
Gas	-	4	4	7	9	11	15	1	4	5.5
Power generation	**189**	**244**	**239**	**226**	**207**	**190**	**179**	**100**	**100**	**-1.2**
Coal	189	244	239	224	203	184	170	100	95	-1.4
Oil	-	0	0	0	0	1	1	0	0	6.9
Gas	-	-	-	2	3	5	8	-	5	n.a.
TFC	**89**	**140**	**138**	**142**	**145**	**149**	**155**	**100**	**100**	**0.5**
Coal	42	67	64	60	58	55	54	47	35	-0.7
Oil	47	69	70	77	82	87	94	50	61	1.3
Transport	*35*	*54*	*54*	*64*	*69*	*75*	*82*	*39*	*53*	*1.7*
Gas	-	4	4	5	5	6	7	3	4	2.0

South Africa: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**285**	**317**	**390**	**254**	**257**	**285**	**100**	**100**	**2.0**	**0.7**
Coal	240	239	251	181	129	30	64	10	0.5	-8.1
Oil	0	0	1	0	1	1	0	0	6.7	5.0
Gas	5	11	22	10	16	38	6	13	n.a.	n.a.
Nuclear	14	27	43	14	26	54	11	19	5.9	6.9
Renewables	26	40	73	48	84	163	19	57	9.7	13.5
Hydro	1	2	4	1	2	4	1	2	7.4	8.3
Bioenergy	4	8	15	4	9	18	4	6	17.7	18.5
Wind	10	14	23	18	25	42	6	15	7.1	9.9
Geothermal	0	0	0	0	0	0	0	0	n.a.	n.a.
Solar PV	8	12	22	21	37	73	6	26	9.6	15.1
CSP	2	4	9	4	10	25	2	9	n.a.	n.a.
Marine	-	-	-	0	0	0	-	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**70**	**80**	**102**	**75**	**87**	**114**	**100**	**100**	**2.8**	**3.3**
Coal	46	47	52	41	36	25	51	22	1.2	-1.9
Oil	3	3	3	3	3	3	3	3	-0.5	-0.6
Gas	4	6	11	3	4	10	11	9	n.a.	n.a.
Nuclear	2	4	6	2	4	8	6	7	4.7	6.0
Renewables	14	19	29	25	40	68	29	60	6.5	10.3
Hydro	4	4	5	4	4	5	5	5	1.5	1.9
Bioenergy	1	2	3	1	2	4	3	4	11.8	12.5
Wind	4	5	7	6	9	13	7	12	6.7	9.5
Geothermal	0	0	0	0	0	0	0	0	n.a.	n.a.
Solar PV	5	7	11	12	21	38	11	33	8.9	14.5
CSP	1	2	3	2	4	8	3	7	n.a.	n.a.
Marine	-	-	-	0	0	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**426**	**427**	**446**	**355**	**291**	**169**	**100**	**100**	**0.3**	**-3.7**
Coal	338	329	323	272	205	76	72	45	-0.2	-6.0
Oil	81	89	109	74	74	72	24	43	1.7	0.0
Gas	7	9	14	9	11	20	3	12	5.2	6.7
Power generation	**239**	**233**	**231**	**182**	**124**	**17**	**100**	**100**	**-0.1**	**-10.5**
Coal	237	229	223	178	118	3	96	18	-0.3	-16.6
Oil	0	0	1	0	0	0	0	3	7.4	5.4
Gas	2	4	8	3	6	13	3	79	n.a.	n.a.
TFC	**147**	**154**	**174**	**133**	**126**	**113**	**100**	**100**	**1.0**	**-0.8**
Coal	63	63	62	56	49	35	36	31	-0.2	-2.5
Oil	79	86	106	72	72	70	61	62	1.8	0.0
Transport	*65*	*72*	*92*	*59*	*60*	*60*	*53*	*53*	*2.3*	*0.4*
Gas	5	5	6	5	6	7	4	6	1.8	2.1

Middle East: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**353**	**737**	**743**	**879**	**992**	**1 117**	**1 226**	**100**	**100**	**2.1**
Coal	2	2	3	5	6	6	6	0	1	3.7
Oil	205	345	339	377	396	428	459	46	37	1.3
Gas	145	386	398	473	547	614	663	53	54	2.2
Nuclear	-	1	1	13	19	27	36	0	3	17.5
Hydro	1	2	2	3	3	3	4	0	0	2.7
Bioenergy	0	1	1	3	5	8	12	0	1	11.4
Other renewables	0	0	0	6	16	31	48	0	4	23.0
Power generation	**114**	**267**	**277**	**304**	**331**	**369**	**404**	**100**	**100**	**1.6**
Coal	0	0	0	3	3	3	3	0	1	12.6
Oil	47	102	102	88	70	61	60	37	15	-2.2
Gas	65	163	172	195	227	254	268	62	66	1.9
Nuclear	-	1	1	13	19	27	36	0	9	17.5
Hydro	1	2	2	3	3	3	4	1	1	2.7
Bioenergy	-	0	0	1	2	4	7	0	2	27.9
Other renewables	0	0	0	3	8	16	27	0	7	24.7
Other energy sector	**36**	**75**	**76**	**91**	**102**	**110**	**115**	**100**	**100**	**1.8**
Electricity	*8*	*17*	*18*	*22*	*26*	*30*	*33*	*24*	*29*	*2.6*
TFC	**241**	**485**	**486**	**599**	**696**	**800**	**891**	**100**	**100**	**2.6**
Coal	0	2	2	2	2	2	2	0	0	-0.3
Oil	145	232	227	274	309	350	383	47	43	2.2
Gas	65	177	179	225	263	298	329	37	37	2.6
Electricity	29	73	76	93	112	132	151	16	17	2.9
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	0	1	1	2	3	4	5	0	1	8.1
Other renewables	0	0	0	3	8	15	21	0	2	21.5
Industry	**59**	**122**	**122**	**148**	**166**	**185**	**203**	**100**	**100**	**2.1**
Coal	0	2	2	2	2	2	2	2	1	-0.3
Oil	23	19	18	18	19	20	21	14	10	0.7
Gas	29	87	88	109	123	138	152	72	75	2.3
Electricity	6	14	15	18	21	23	25	12	12	2.3
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	-	-	-	1	1	2	3	-	1	n.a.
Other renewables	0	0	0	0	0	0	0	0	0	23.7
Transport	**71**	**136**	**130**	**157**	**178**	**204**	**224**	**100**	**100**	**2.3**
Oil	71	129	124	148	169	194	212	95	95	2.3
Electricity	0	-	-	0	0	0	0	-	0	n.a.
Biofuels	-	-	-	-	-	-	-	-	-	n.a.
Other fuels	0	7	7	9	9	10	12	5	5	2.3
Buildings	**75**	**143**	**145**	**177**	**219**	**262**	**299**	**100**	**100**	**3.1**
Coal	0	0	0	0	0	0	0	0	0	-1.6
Oil	25	18	17	15	15	15	15	12	5	-0.5
Gas	27	68	69	87	109	127	141	47	47	3.1
Electricity	22	56	58	71	86	104	120	40	40	3.1
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	0	1	1	1	1	2	2	1	1	4.3
Traditional biomass	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.7*
Other renewables	0	0	0	3	8	14	20	0	7	21.3
Other	**36**	**85**	**88**	**116**	**133**	**149**	**166**	**100**	**100**	**2.7**
Petrochem. feedstock	*23*	*65*	*68*	*94*	*108*	*123*	*138*	*47*	*46*	*3.0*

Middle East: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**902**	**1 032**	**1 332**	**821**	**873**	**964**	**100**	**100**	**2.5**	**1.1**
Coal	5	6	7	5	5	5	0	0	4.0	2.6
Oil	385	417	518	341	321	295	39	31	1.8	-0.6
Gas	489	575	738	447	483	456	55	47	2.6	0.6
Nuclear	13	14	23	14	26	52	2	5	15.4	19.4
Hydro	2	3	3	3	4	5	0	1	2.5	4.1
Bioenergy	3	4	10	3	5	14	1	1	10.9	12.2
Other renewables	5	13	33	9	31	138	2	14	21.1	28.6
Power generation	**318**	**351**	**445**	**276**	**285**	**300**	**100**	**100**	**2.0**	**0.3**
Coal	3	3	4	2	2	2	1	1	12.9	11.1
Oil	88	72	64	69	42	16	14	5	-1.9	-7.3
Gas	208	251	333	182	188	114	75	38	2.8	-1.7
Nuclear	13	14	23	14	26	52	5	17	15.4	19.4
Hydro	2	3	3	3	4	5	1	2	2.5	4.1
Bioenergy	0	1	5	1	2	8	1	3	26.6	29.2
Other renewables	3	6	13	6	20	101	3	34	21.2	31.8
Other energy sector	**94**	**108**	**129**	**83**	**88**	**87**	**100**	**100**	**2.3**	**0.6**
Electricity	*23*	*28*	*37*	*21*	*23*	*27*	*29*	*31*	*3.1*	*1.7*
TFC	**612**	**721**	**961**	**572**	**629**	**741**	**100**	**100**	**2.9**	**1.8**
Coal	2	2	2	2	2	1	0	0	-0.2	-1.8
Oil	280	325	434	260	268	272	45	37	2.7	0.8
Gas	227	265	335	216	241	288	35	39	2.6	2.0
Electricity	98	119	166	90	105	137	17	19	3.3	2.5
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	2	3	5	2	3	5	1	1	8.3	8.4
Other renewables	2	7	19	3	10	37	2	5	21.0	24.3
Industry	**149**	**167**	**207**	**142**	**152**	**164**	**100**	**100**	**2.2**	**1.2**
Coal	2	2	2	2	1	1	1	1	-0.2	-2.1
Oil	18	19	21	17	17	17	10	10	0.7	-0.2
Gas	109	124	155	104	111	117	75	71	2.4	1.2
Electricity	18	21	26	18	20	24	13	15	2.4	2.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	1	1	3	1	2	4	2	2	n.a.	n.a.
Other renewables	0	0	0	0	0	2	0	1	23.1	34.9
Transport	**161**	**191**	**268**	**150**	**154**	**161**	**100**	**100**	**3.1**	**0.9**
Oil	154	184	260	138	135	115	97	71	3.2	-0.3
Electricity	0	0	0	0	1	3	0	2	n.a.	n.a.
Biofuels	-	-	-	-	-	-	-	-	n.a.	n.a.
Other fuels	8	7	8	12	18	43	3	27	0.7	7.9
Buildings	**186**	**231**	**321**	**166**	**196**	**259**	**100**	**100**	**3.4**	**2.4**
Coal	0	0	0	0	0	0	0	0	-1.6	-4.5
Oil	16	17	19	14	13	13	6	5	0.3	-1.3
Gas	91	113	148	81	92	105	46	41	3.3	1.8
Electricity	75	93	134	67	80	105	42	41	3.5	2.5
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	1	1	2	1	1	2	1	1	4.2	3.7
Traditional biomass	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.7*	*-4.1*
Other renewables	2	7	18	3	9	34	6	13	20.8	23.9
Other	**116**	**132**	**165**	**114**	**127**	**156**	**100**	**100**	**2.7**	**2.4**
Petrochem. feedstock	*93*	*107*	*136*	*91*	*104*	*133*	*42*	*51*	*3.0*	*2.8*

Middle East: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**430**	**1 050**	**1 091**	**1 338**	**1 597**	**1 879**	**2 138**	**100**	**100**	**2.8**
Coal	0	1	1	12	14	15	16	0	1	14.9
Oil	175	338	340	308	257	228	224	31	10	-1.7
Gas	246	687	724	909	1 139	1 334	1 455	66	68	3.0
Nuclear	-	3	3	49	72	102	137	0	6	17.5
Renewables	8	21	23	59	115	200	306	2	14	11.3
Hydro	8	20	22	30	35	39	42	2	2	2.7
Bioenergy	-	0	0	2	6	14	23	0	1	27.9
Wind	0	1	1	10	28	57	101	0	5	23.5
Geothermal	-	-	-	-	-	-	-	-	-	n.a.
Solar PV	-	0	0	14	33	61	94	0	4	34.7
CSP	-	0	0	4	13	28	46	0	2	23.8
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**302**	**310**	**405**	**467**	**536**	**597**	**100**	**100**	**2.8**
Coal	0	0	3	3	4	4	0	1	10.8
Oil	86	88	88	73	65	64	28	11	-1.3
Gas	197	204	274	324	365	383	66	64	2.7
Nuclear	1	1	7	11	15	19	0	3	13.0
Renewables	17	17	33	56	88	128	6	21	8.7
Hydro	16	16	20	23	25	26	5	4	2.0
Bioenergy	0	0	0	1	2	4	0	1	30.7
Wind	0	0	4	10	21	37	0	6	21.6
Geothermal	-	-	-	-	-	-	-	-	n.a.
Solar PV	0	0	7	17	30	45	0	8	20.8
CSP	0	0	1	5	10	16	0	3	23.4
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**879**	**1 756**	**1 748**	**1 953**	**2 134**	**2 334**	**2 495**	**100**	**100**	**1.5**
Coal	4	11	10	19	20	21	21	1	1	3.3
Oil	556	912	866	902	914	968	1 020	50	41	0.7
Gas	320	834	872	1 032	1 199	1 345	1 454	50	58	2.2
Power generation	**304**	**703**	**724**	**744**	**765**	**802**	**832**	**100**	**100**	**0.6**
Coal	1	2	1	10	12	12	13	0	2	12.6
Oil	149	318	320	275	221	193	189	44	23	-2.2
Gas	154	382	403	459	532	597	630	56	76	1.9
TFC	**508**	**926**	**897**	**1 061**	**1 206**	**1 363**	**1 489**	**100**	**100**	**2.1**
Coal	2	7	8	7	7	7	7	1	0	-0.3
Oil	374	553	506	576	640	720	777	56	52	1.8
Transport	*211*	*386*	*370*	*444*	*505*	*581*	*634*	*41*	*43*	*2.3*
Gas	132	366	383	478	559	635	705	43	47	2.6

Middle East: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						**Shares** (%)		**CAAGR** (%)	
	2025	**2030**	**2040**	**2025**	**2030**	**2040**	**2040**		**2016e-40**	
	Current Policies			**Sustainable Development**			**CPS**	**SDS**	**CPS**	**SDS**
Total generation	**1 404**	**1 702**	**2 352**	**1 275**	**1 482**	**1 903**	**100**	**100**	**3.3**	**2.3**
Coal	12	14	17	12	11	12	1	1	15.3	13.5
Oil	312	266	239	246	156	62	10	3	-1.5	-6.8
Gas	973	1 277	1 823	873	963	667	77	35	3.9	-0.3
Nuclear	50	55	89	52	98	201	4	11	15.4	19.4
Renewables	57	90	185	93	254	960	8	50	9.0	16.7
Hydro	29	34	40	36	46	59	2	3	2.5	4.1
Bioenergy	2	5	18	2	8	30	1	2	26.5	29.2
Wind	9	23	65	24	110	341	3	18	21.2	29.9
Geothermal	-	-	-	-	-	-	-	-	n.a.	n.a.
Solar PV	13	19	44	25	66	325	2	17	30.5	41.8
CSP	4	9	19	7	24	205	1	11	19.3	31.8
Marine	-	-	-	-	0	1	-	0	n.a.	n.a.

	Electrical capacity (GW)						**Shares** (%)		**CAAGR** (%)	
	2025	**2030**	**2040**	**2025**	**2030**	**2040**	**2040**		**2016e-40**	
	Current Policies			**Sustainable Development**			**CPS**	**SDS**	**CPS**	**SDS**
Total capacity	**407**	**469**	**588**	**398**	**467**	**748**	**100**	**100**	**2.7**	**3.7**
Coal	3	3	4	3	3	3	1	0	11.2	9.4
Oil	89	76	68	88	74	66	12	9	-1.0	-1.2
Gas	277	338	424	250	257	256	72	34	3.1	1.0
Nuclear	7	8	12	8	14	28	2	4	11.0	14.9
Renewables	32	45	79	49	118	395	13	53	6.6	14.0
Hydro	20	22	25	24	29	35	4	5	1.9	3.2
Bioenergy	0	1	3	0	1	5	0	1	29.2	32.0
Wind	4	9	23	10	42	123	4	16	19.3	27.8
Geothermal	-	-	-	-	-	-	-	-	n.a.	n.a.
Solar PV	7	10	21	13	36	159	4	21	17.1	27.4
CSP	2	3	6	3	9	74	1	10	18.9	31.6
Marine	-	-	-	-	0	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						**Shares** (%)		**CAAGR** (%)	
	2025	**2030**	**2040**	**2025**	**2030**	**2040**	**2040**		**2016e-40**	
	Current Policies			**Sustainable Development**			**CPS**	**SDS**	**CPS**	**SDS**
Total CO_2	**2 014**	**2 262**	**2 847**	**1 782**	**1 740**	**1 459**	**100**	**100**	**2.1**	**-0.8**
Coal	19	20	23	17	16	14	1	1	3.6	1.6
Oil	926	976	1 197	795	691	533	42	37	1.4	-2.0
Gas	1 069	1 266	1 627	970	1 033	911	57	62	2.6	0.2
Power generation	**777**	**829**	**995**	**654**	**581**	**313**	**100**	**100**	**1.3**	**-3.4**
Coal	10	12	14	10	9	9	1	3	12.9	11.1
Oil	277	227	200	217	131	51	20	16	-1.9	-7.3
Gas	489	590	781	428	440	253	79	81	2.8	-1.9
TFC	**1 088**	**1 265**	**1 663**	**999**	**1 029**	**1 026**	**100**	**100**	**2.6**	**0.6**
Coal	7	7	7	6	6	4	0	0	-0.2	-2.5
Oil	597	692	937	538	523	452	56	44	2.6	-0.5
Transport	*460*	*550*	*778*	*414*	*405*	*343*	*47*	*33*	*3.1*	*-0.3*
Gas	484	565	719	455	500	570	43	56	2.7	1.7

Eurasia: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**743**	**866**	**880**	**919**	**945**	**981**	**1 016**	**100**	**100**	**0.6**
Coal	141	154	148	155	153	156	154	17	15	0.1
Oil	154	167	174	193	198	199	198	20	19	0.5
Gas	386	465	475	481	490	508	526	54	52	0.4
Nuclear	35	52	52	55	59	62	68	6	7	1.1
Hydro	18	20	21	23	24	26	27	2	3	1.0
Bioenergy	8	8	8	10	12	16	20	1	2	3.7
Other renewables	0	0	0	3	8	15	23	0	2	21.8
Power generation	**390**	**412**	**413**	**415**	**421**	**438**	**458**	**100**	**100**	**0.4**
Coal	96	85	83	85	82	82	78	20	17	-0.3
Oil	30	10	10	9	8	7	7	2	1	-1.5
Gas	207	241	242	235	235	238	242	59	53	-0.0
Nuclear	35	52	52	55	59	62	68	13	15	1.1
Hydro	18	20	21	23	24	26	27	5	6	1.0
Bioenergy	4	4	4	5	6	9	13	1	3	4.7
Other renewables	0	0	0	3	8	15	22	0	5	22.1
Other energy sector	**107**	**163**	**163**	**167**	**170**	**174**	**178**	**100**	**100**	**0.4**
Electricity	*26*	*34*	*35*	*34*	*34*	*35*	*36*	*21*	*20*	*0.1*
TFC	**500**	**542**	**553**	**602**	**628**	**655**	**676**	**100**	**100**	**0.8**
Coal	22	24	23	26	27	29	30	4	4	1.1
Oil	109	141	148	164	169	171	170	27	25	0.6
Gas	156	181	188	201	210	220	230	34	34	0.8
Electricity	63	78	79	91	98	105	112	14	17	1.4
Heat	146	113	111	116	119	123	126	20	19	0.5
Bioenergy	4	4	4	5	6	7	7	1	1	2.7
Other renewables	0	0	0	0	0	1	1	0	0	17.9
Industry	**148**	**186**	**189**	**214**	**226**	**238**	**249**	**100**	**100**	**1.2**
Coal	11	17	16	19	21	23	25	9	10	1.8
Oil	19	26	27	29	29	28	27	14	11	0.0
Gas	34	68	72	77	80	84	87	38	35	0.8
Electricity	31	35	36	42	45	48	51	19	20	1.5
Heat	53	38	37	45	48	52	55	20	22	1.6
Bioenergy	1	1	1	2	2	3	3	0	1	5.4
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Transport	**86**	**112**	**116**	**124**	**129**	**133**	**135**	**100**	**100**	**0.6**
Oil	51	74	77	81	83	83	82	66	61	0.3
Electricity	6	8	8	9	10	11	12	7	9	2.0
Biofuels	0	0	0	0	0	0	0	0	0	0.0
Other fuels	30	31	32	35	36	38	41	28	30	1.0
Buildings	**207**	**202**	**204**	**208**	**214**	**221**	**226**	**100**	**100**	**0.4**
Coal	10	7	7	6	6	5	5	3	2	-1.3
Oil	11	18	19	20	20	21	21	9	9	0.6
Gas	73	70	73	76	79	83	86	36	38	0.7
Electricity	22	32	32	35	37	40	42	16	18	1.1
Heat	88	72	71	68	68	68	68	35	30	-0.2
Bioenergy	3	3	3	3	3	4	4	1	2	1.2
Traditional biomass	-	-	-	-	-	-	-	-	-	*n.a.*
Other renewables	0	0	0	0	0	0	0	0	0	15.4
Other	**59**	**42**	**44**	**56**	**60**	**63**	**65**	**100**	**100**	**1.7**
Petrochem. feedstock	*29*	*18*	*19*	*30*	*33*	*36*	*38*	*9*	*17*	*3.0*

Eurasia: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**942**	**981**	**1 077**	**882**	**873**	**877**	**100**	**100**	**0.8**	**-0.0**
Coal	161	164	166	124	104	74	15	8	0.5	-2.9
Oil	197	207	212	186	184	168	20	19	0.8	-0.2
Gas	492	509	566	463	443	420	53	48	0.7	-0.5
Nuclear	58	60	74	67	78	91	7	10	1.4	2.3
Hydro	23	24	28	24	29	38	3	4	1.1	2.5
Bioenergy	10	11	16	11	18	38	2	4	2.8	6.5
Other renewables	2	6	13	7	18	48	1	5	19.1	25.6
Power generation	**427**	**438**	**480**	**400**	**393**	**407**	**100**	**100**	**0.6**	**-0.1**
Coal	91	93	91	63	46	24	19	6	0.4	-5.1
Oil	9	8	7	8	7	5	1	1	-1.5	-2.4
Gas	240	242	258	226	205	176	54	43	0.3	-1.3
Nuclear	58	60	74	67	78	91	15	22	1.4	2.3
Hydro	23	24	28	24	29	38	6	9	1.1	2.5
Bioenergy	5	6	9	6	12	28	2	7	3.3	8.2
Other renewables	2	6	13	6	16	44	3	11	19.4	25.7
Other energy sector	**170**	**175**	**190**	**155**	**149**	**138**	**100**	**100**	**0.7**	**-0.7**
Electricity	*36*	*36*	*39*	*32*	*31*	*29*	*20*	*21*	*0.5*	*-0.7*
TFC	**616**	**652**	**718**	**579**	**584**	**583**	**100**	**100**	**1.1**	**0.2**
Coal	26	28	31	23	22	21	4	4	1.1	-0.5
Oil	168	176	185	158	158	143	26	25	1.0	-0.1
Gas	206	219	246	194	196	202	34	35	1.1	0.3
Electricity	93	101	116	85	89	98	16	17	1.6	0.9
Heat	118	123	132	112	111	107	18	18	0.7	-0.2
Bioenergy	5	5	7	5	7	9	1	2	2.5	3.8
Other renewables	0	0	1	0	1	4	0	1	15.2	25.0
Industry	**217**	**232**	**259**	**204**	**207**	**211**	**100**	**100**	**1.3**	**0.5**
Coal	19	21	25	18	18	18	10	9	1.8	0.5
Oil	28	28	26	28	27	27	10	13	-0.1	-0.0
Gas	79	84	95	73	73	71	37	34	1.2	-0.0
Electricity	42	46	52	40	41	44	20	21	1.6	0.9
Heat	46	50	57	43	44	44	22	21	1.8	0.7
Bioenergy	2	2	3	2	3	5	1	2	5.7	7.4
Other renewables	0	0	0	0	0	2	0	1	n.a.	n.a.
Transport	**128**	**135**	**149**	**121**	**122**	**118**	**100**	**100**	**1.0**	**0.0**
Oil	84	88	94	79	77	64	63	55	0.9	-0.7
Electricity	8	9	11	9	10	15	8	13	1.6	2.9
Biofuels	0	0	0	0	0	0	0	0	0.0	0.0
Other fuels	36	38	43	33	34	38	29	32	1.2	0.7
Buildings	**215**	**224**	**242**	**199**	**197**	**193**	**100**	**100**	**0.7**	**-0.2**
Coal	6	6	6	5	4	2	2	1	-0.7	-5.0
Oil	21	22	24	18	17	15	10	8	1.1	-0.8
Gas	78	83	93	75	76	78	38	41	1.0	0.3
Electricity	37	40	45	32	32	33	18	17	1.4	0.1
Heat	70	70	72	67	65	60	30	31	0.0	-0.7
Bioenergy	3	3	3	3	3	3	1	2	0.5	0.2
Traditional biomass	-	-	-	-	-	-	-	-	*n.a.*	*n.a.*
Other renewables	0	0	0	0	1	1	0	1	12.4	20.6
Other	**57**	**61**	**68**	**55**	**58**	**62**	**100**	**100**	**1.8**	**1.4**
Petrochem. feedstock	*29*	*33*	*38*	*29*	*32*	*37*	*16*	*19*	*3.0*	*2.8*

Eurasia: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**1 046**	**1 314**	**1 340**	**1 443**	**1 516**	**1 595**	**1 677**	**100**	**100**	**0.9**
Coal	214	239	227	251	243	245	238	17	14	0.2
Oil	54	11	11	7	5	3	2	1	0	-6.3
Gas	429	633	651	693	726	741	750	49	45	0.6
Nuclear	133	198	200	212	223	236	261	15	16	1.1
Renewables	216	233	251	280	318	369	425	19	25	2.2
Hydro	213	228	247	265	281	297	311	18	19	1.0
Bioenergy	3	3	3	5	9	19	33	0	2	10.5
Wind	0	0	0	6	18	37	57	0	3	23.2
Geothermal	0	0	0	3	7	13	20	0	1	17.2
Solar PV	-	0	0	1	2	3	4	0	0	9.3
CSP	-	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**319**	**323**	**339**	**350**	**367**	**389**	**100**	**100**	**0.8**
Coal	67	67	59	51	49	45	21	11	-1.7
Oil	9	9	6	3	2	1	3	0	-8.1
Gas	145	147	162	171	174	183	46	47	0.9
Nuclear	28	28	31	32	34	36	9	9	1.0
Renewables	71	71	82	94	109	124	22	32	2.3
Hydro	69	69	75	79	83	87	21	22	1.0
Bioenergy	1	1	2	3	5	8	0	2	7.2
Wind	0	0	3	8	15	23	0	6	21.4
Geothermal	0	0	0	1	2	3	0	1	15.5
Solar PV	0	0	2	2	3	4	0	1	13.4
CSP	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**1 761**	**1 888**	**1 902**	**1 945**	**1 960**	**1 997**	**2 013**	**100**	**100**	**0.2**
Coal	525	480	464	482	473	482	474	24	24	0.1
Oil	391	419	431	439	442	438	430	23	21	-0.0
Gas	845	989	1 007	1 025	1 045	1 078	1 110	53	55	0.4
Power generation	**993**	**956**	**949**	**936**	**916**	**922**	**916**	**100**	**100**	**-0.1**
Coal	410	353	345	352	336	337	322	36	35	-0.3
Oil	95	36	33	29	26	23	23	3	2	-1.5
Gas	488	567	572	556	554	562	572	60	62	-0.0
TFC	**697**	**807**	**826**	**885**	**917**	**946**	**967**	**100**	**100**	**0.7**
Coal	112	121	114	124	131	138	146	14	15	1.0
Oil	262	341	354	372	378	378	372	43	38	0.2
Transport	*151*	*218*	*227*	*240*	*246*	*247*	*243*	*27*	*25*	*0.3*
Gas	323	344	358	390	408	430	450	43	46	0.9

Eurasia: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**1 489**	**1 585**	**1 775**	**1 370**	**1 384**	**1 463**	**100**	**100**	**1.2**	**0.4**
Coal	270	286	300	166	116	40	17	3	1.2	-7.0
Oil	7	5	2	7	5	2	0	0	-6.5	-6.4
Gas	715	762	817	636	542	372	46	25	1.0	-2.3
Nuclear	220	230	282	255	297	348	16	24	1.4	2.3
Renewables	276	302	373	306	423	701	21	48	1.7	4.4
Hydro	266	282	321	281	333	442	18	30	1.1	2.5
Bioenergy	5	8	22	8	30	91	1	6	8.6	15.2
Wind	2	4	13	7	41	116	1	8	16.0	26.9
Geothermal	2	6	14	7	15	39	1	3	15.3	20.4
Solar PV	1	1	2	2	5	13	0	1	6.7	15.5
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	-	-	-	0	1	-	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**344**	**355**	**398**	**334**	**351**	**412**	**100**	**100**	**0.9**	**1.0**
Coal	61	55	54	51	35	17	13	4	-0.9	-5.6
Oil	6	3	1	6	3	1	0	0	-8.6	-8.5
Gas	166	177	200	151	145	139	50	34	1.3	-0.2
Nuclear	32	34	39	37	41	49	10	12	1.3	2.3
Renewables	80	86	105	90	127	206	26	50	1.6	4.5
Hydro	75	80	90	80	94	123	23	30	1.1	2.4
Bioenergy	2	3	5	3	8	20	1	5	5.5	11.5
Wind	1	2	5	3	19	44	1	11	14.4	24.9
Geothermal	0	1	2	1	2	5	0	1	13.6	18.7
Solar PV	1	1	2	3	5	13	1	3	10.7	19.7
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	-	-	-	0	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**2 006**	**2 070**	**2 197**	**1 778**	**1 628**	**1 368**	**100**	**100**	**0.6**	**-1.4**
Coal	508	521	530	374	295	186	24	14	0.6	-3.7
Oil	451	465	477	422	404	341	22	25	0.4	-1.0
Gas	1 047	1 084	1 190	982	928	841	54	61	0.7	-0.7
Power generation	**972**	**981**	**1 009**	**820**	**691**	**519**	**100**	**100**	**0.3**	**-2.5**
Coal	377	383	377	260	189	98	37	19	0.4	-5.1
Oil	28	26	22	27	24	18	2	4	-1.5	-2.4
Gas	566	572	610	534	479	402	60	78	0.3	-1.5
TFC	**908**	**957**	**1 044**	**844**	**830**	**758**	**100**	**100**	**1.0**	**-0.4**
Coal	125	132	147	110	102	84	14	11	1.1	-1.2
Oil	383	400	417	358	347	294	40	39	0.7	-0.8
Transport	*248*	*262*	*280*	*235*	*230*	*191*	*27*	*25*	*0.9*	*-0.7*
Gas	400	426	481	376	380	379	46	50	1.2	0.2

Russia: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**620**	**689**	**699**	**711**	**721**	**739**	**755**	**100**	**100**	**0.3**
Coal	120	116	110	109	104	104	99	16	13	-0.4
Oil	126	134	140	150	153	151	148	20	20	0.2
Gas	319	365	374	370	373	379	385	53	51	0.1
Nuclear	34	51	52	55	56	59	66	7	9	1.0
Hydro	14	14	16	17	18	19	19	2	3	0.8
Bioenergy	7	8	8	8	10	13	17	1	2	3.5
Other renewables	0	0	0	2	7	13	20	0	3	22.5
Power generation	**342**	**350**	**350**	**346**	**347**	**358**	**370**	**100**	**100**	**0.2**
Coal	80	65	62	60	55	55	50	18	14	-0.9
Oil	23	9	9	8	8	7	7	3	2	-1.1
Gas	186	206	207	198	198	196	196	59	53	-0.2
Nuclear	34	51	52	55	56	59	66	15	18	1.0
Hydro	14	14	16	17	18	19	19	5	5	0.8
Bioenergy	4	4	4	5	6	9	12	1	3	4.6
Other renewables	0	0	0	2	7	13	20	0	5	22.4
Other energy sector	**90**	**119**	**118**	**117**	**117**	**118**	**120**	**100**	**100**	**0.1**
Electricity	*22*	*28*	*28*	*27*	*27*	*27*	*27*	*24*	*23*	*-0.2*
TFC	**418**	**435**	**445**	**469**	**482**	**495**	**502**	**100**	**100**	**0.5**
Coal	18	12	11	12	12	12	12	3	2	0.3
Oil	91	113	118	126	128	128	124	26	25	0.2
Gas	117	141	148	154	158	163	168	33	34	0.5
Electricity	52	62	63	70	74	78	82	14	16	1.1
Heat	137	103	101	104	106	109	111	23	22	0.4
Bioenergy	3	3	3	3	4	4	5	1	1	1.7
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Industry	**127**	**156**	**159**	**175**	**182**	**189**	**195**	**100**	**100**	**0.8**
Coal	7	8	8	9	10	10	11	5	6	1.3
Oil	16	22	23	24	24	24	23	14	12	-0.0
Gas	26	60	63	65	67	69	70	40	36	0.4
Electricity	27	28	29	32	34	36	37	18	19	1.1
Heat	50	37	36	43	46	49	51	22	26	1.5
Bioenergy	1	1	1	1	2	2	2	1	1	3.9
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Transport	**74**	**94**	**98**	**102**	**103**	**104**	**103**	**100**	**100**	**0.2**
Oil	42	60	62	63	63	61	58	64	56	-0.3
Electricity	5	7	7	8	9	10	11	7	10	1.8
Biofuels	-	-	-	-	-	-	-	-	-	n.a.
Other fuels	27	27	29	30	32	33	34	29	33	0.7
Buildings	**165**	**151**	**153**	**149**	**150**	**153**	**154**	**100**	**100**	**0.0**
Coal	10	3	3	2	2	1	1	2	1	-4.9
Oil	7	11	11	11	12	12	12	7	8	0.3
Gas	47	44	47	47	49	50	52	31	34	0.4
Electricity	18	26	26	27	29	30	31	17	20	0.7
Heat	82	64	64	59	58	57	57	42	37	-0.5
Bioenergy	2	2	2	2	2	2	2	1	1	-0.2
Traditional biomass	-	-	-	-	-	-	-	-	-	*n.a.*
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Other	**51**	**34**	**35**	**43**	**46**	**49**	**50**	**100**	**100**	**1.5**
Petrochem. feedstock	*28*	*16*	*17*	*24*	*27*	*30*	*31*	*11*	*20*	*2.7*

Russia: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**731**	**752**	**804**	**686**	**671**	**667**	**100**	**100**	**0.6**	**-0.2**
Coal	114	113	109	86	67	47	14	7	-0.0	-3.5
Oil	154	159	160	146	144	129	20	19	0.6	-0.3
Gas	378	389	418	355	336	307	52	46	0.5	-0.8
Nuclear	57	57	71	65	73	82	9	12	1.3	2.0
Hydro	17	18	21	18	21	27	3	4	1.1	2.2
Bioenergy	8	9	14	9	16	33	2	5	2.5	6.4
Other renewables	2	5	12	6	15	42	1	6	19.7	26.2
Power generation	**357**	**363**	**389**	**336**	**327**	**341**	**100**	**100**	**0.4**	**-0.1**
Coal	66	65	61	44	29	17	16	5	-0.1	-5.3
Oil	8	8	7	8	7	5	2	2	-1.2	-2.0
Gas	202	204	209	190	171	142	54	42	0.1	-1.6
Nuclear	57	57	71	65	73	82	18	24	1.3	2.0
Hydro	17	18	21	18	21	27	5	8	1.1	2.2
Bioenergy	5	5	9	5	11	27	2	8	3.2	8.1
Other renewables	2	5	12	5	14	40	3	12	19.7	25.9
Other energy sector	**119**	**120**	**127**	**109**	**102**	**93**	**100**	**100**	**0.3**	**-1.0**
Electricity	*28*	*29*	*30*	*26*	*24*	*23*	*24*	*25*	*0.2*	*-0.9*
TFC	**481**	**503**	**539**	**452**	**450**	**438**	**100**	**100**	**0.8**	**-0.1**
Coal	12	12	12	10	9	8	2	2	0.2	-1.6
Oil	130	134	136	123	121	106	25	24	0.6	-0.4
Gas	159	167	184	148	148	148	34	34	0.9	-0.0
Electricity	71	77	85	65	67	73	16	17	1.3	0.6
Heat	107	110	117	101	100	95	22	22	0.6	-0.3
Bioenergy	3	4	4	4	4	6	1	1	1.6	2.6
Other renewables	0	0	0	0	1	2	0	1	n.a.	n.a.
Industry	**177**	**187**	**204**	**167**	**167**	**168**	**100**	**100**	**1.0**	**0.2**
Coal	9	10	10	8	8	7	5	4	1.2	-0.4
Oil	24	23	22	23	23	22	11	13	-0.2	-0.1
Gas	67	71	77	63	61	59	38	35	0.8	-0.3
Electricity	32	35	38	31	32	33	19	20	1.2	0.6
Heat	43	47	54	41	41	41	26	24	1.7	0.6
Bioenergy	1	2	2	2	2	3	1	2	3.8	5.2
Other renewables	0	0	0	0	0	2	0	1	n.a.	n.a.
Transport	**105**	**109**	**115**	**99**	**97**	**88**	**100**	**100**	**0.7**	**-0.4**
Oil	66	67	68	62	60	46	59	52	0.3	-1.2
Electricity	8	8	10	8	9	14	9	16	1.4	2.8
Biofuels	-	-	-	-	-	-	-	-	n.a.	n.a.
Other fuels	32	33	37	28	28	28	32	32	1.1	-0.1
Buildings	**155**	**159**	**168**	**144**	**141**	**134**	**100**	**100**	**0.4**	**-0.5**
Coal	2	2	1	2	1	0	1	0	-4.6	-9.9
Oil	12	13	14	10	9	8	8	6	1.1	-1.3
Gas	49	52	58	48	48	50	34	37	0.9	0.3
Electricity	29	31	33	24	24	23	20	17	1.0	-0.5
Heat	61	60	60	58	56	51	36	38	-0.3	-0.9
Bioenergy	2	2	2	2	2	1	1	1	-0.2	-1.3
Traditional biomass	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*n.a.*	*n.a.*
Other renewables	0	0	0	0	0	1	0	0	n.a.	n.a.
Other	**44**	**47**	**52**	**43**	**45**	**48**	**100**	**100**	**1.6**	**1.3**
Petrochem. feedstock	*24*	*27*	*31*	*24*	*27*	*31*	*19*	*23*	*2.7*	*2.6*

Russia: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**876**	**1 055**	**1 076**	**1 124**	**1 168**	**1 213**	**1 251**	**100**	**100**	**0.6**
Coal	176	158	145	154	141	143	131	13	11	-0.4
Oil	33	8	8	6	5	3	2	1	0	-5.0
Gas	370	521	536	544	568	557	537	50	43	0.0
Nuclear	131	195	197	210	213	226	251	18	20	1.0
Renewables	167	172	190	209	241	283	329	18	26	2.3
Hydro	164	168	186	198	209	219	226	17	18	0.8
Bioenergy	3	3	3	5	9	18	32	0	3	10.6
Wind	0	0	0	4	16	33	51	0	4	27.6
Geothermal	0	0	0	2	6	12	18	0	1	16.6
Solar PV	-	0	0	1	1	2	2	0	0	8.7
CSP	-	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**256**	**259**	**260**	**264**	**271**	**282**	**100**	**100**	**0.4**
Coal	51	52	39	30	27	23	20	8	-3.3
Oil	4	4	2	2	1	1	1	0	-5.1
Gas	121	122	127	130	127	128	47	45	0.2
Nuclear	27	28	30	31	32	34	11	12	0.9
Renewables	53	54	61	71	83	96	21	34	2.5
Hydro	52	52	56	59	61	63	20	22	0.8
Bioenergy	1	1	2	3	5	8	1	3	7.1
Wind	0	0	2	7	14	20	0	7	24.7
Geothermal	0	0	0	1	2	3	0	1	15.0
Solar PV	0	0	1	1	2	2	0	1	14.9
CSP	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**1 456**	**1 441**	**1 450**	**1 433**	**1 415**	**1 411**	**1 385**	**100**	**100**	**-0.2**
Coal	443	346	327	321	300	301	282	23	20	-0.6
Oil	318	329	339	335	330	318	305	23	22	-0.4
Gas	695	765	784	777	785	791	798	54	58	0.1
Power generation	**860**	**791**	**778**	**748**	**724**	**717**	**694**	**100**	**100**	**-0.5**
Coal	347	272	260	252	230	230	210	33	30	-0.9
Oil	75	33	30	27	26	23	23	4	3	-1.1
Gas	438	486	488	469	468	464	462	63	67	-0.2
TFC	**541**	**583**	**602**	**622**	**630**	**634**	**632**	**100**	**100**	**0.2**
Coal	94	69	62	64	65	67	67	10	11	0.3
Oil	212	260	270	275	273	265	253	45	40	-0.3
Transport	*126*	*177*	*185*	*188*	*187*	*181*	*172*	*31*	*27*	*-0.3*
Gas	235	254	269	283	291	302	311	45	49	0.6

Russia: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**1 163**	**1 225**	**1 328**	**1 069**	**1 067**	**1 110**	**100**	**100**	**0.9**	**0.1**
Coal	172	181	186	103	57	21	14	2	1.0	-7.8
Oil	6	5	2	6	5	2	0	0	-5.3	-5.2
Gas	559	592	585	483	401	228	44	20	0.4	-3.5
Nuclear	219	219	272	249	279	316	20	28	1.3	2.0
Renewables	207	228	283	228	325	544	21	49	1.7	4.5
Hydro	199	212	240	209	246	313	18	28	1.1	2.2
Bioenergy	5	7	21	8	29	88	2	8	8.7	15.4
Wind	1	2	9	5	35	99	1	9	18.5	31.2
Geothermal	2	6	13	6	13	36	1	3	15.0	19.9
Solar PV	1	1	1	1	2	9	0	1	4.4	14.5
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	-	-	-	0	1	-	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**264**	**266**	**288**	**252**	**259**	**298**	**100**	**100**	**0.4**	**0.6**
Coal	41	34	31	35	22	9	11	3	-2.2	-7.1
Oil	2	2	1	2	2	1	0	0	-5.6	-5.4
Gas	129	134	141	113	101	86	49	29	0.6	-1.4
Nuclear	31	32	37	36	39	45	13	15	1.2	2.0
Renewables	59	64	78	66	97	157	27	53	1.6	4.6
Hydro	56	59	67	59	69	86	23	29	1.1	2.1
Bioenergy	2	2	5	3	7	20	2	7	5.3	11.4
Wind	0	1	4	2	16	38	1	13	16.0	28.0
Geothermal	0	1	2	1	2	5	1	2	13.3	18.1
Solar PV	1	1	1	1	2	9	0	3	10.3	21.0
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	-	-	-	0	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**1 484**	**1 507**	**1 531**	**1 314**	**1 170**	**948**	**100**	**100**	**0.2**	**-1.8**
Coal	345	342	326	245	170	101	21	11	-0.0	-4.8
Oil	344	347	341	323	306	245	22	26	0.0	-1.3
Gas	795	817	864	746	694	601	56	63	0.4	-1.1
Power generation	**780**	**781**	**773**	**659**	**543**	**409**	**100**	**100**	**-0.0**	**-2.6**
Coal	276	273	256	187	121	70	33	17	-0.1	-5.3
Oil	27	26	22	26	23	18	3	4	-1.2	-2.0
Gas	476	482	494	447	399	321	64	78	0.1	-1.7
TFC	**640**	**662**	**695**	**595**	**573**	**493**	**100**	**100**	**0.6**	**-0.8**
Coal	64	65	66	55	47	29	9	6	0.2	-3.1
Oil	284	289	288	266	253	203	41	41	0.3	-1.2
Transport	*194*	*198*	*201*	*185*	*176*	*137*	*29*	*28*	*0.4*	*-1.2*
Gas	293	308	342	274	272	261	49	53	1.0	-0.1

Asia Pacific: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**3 009**	**5 606**	**5 699**	**6 679**	**7 226**	**7 684**	**8 068**	**100**	**100**	**1.5**
Coal	1 081	2 784	2 772	2 929	3 027	3 078	3 107	49	39	0.5
Oil	959	1 380	1 418	1 631	1 726	1 780	1 817	25	23	1.0
Gas	257	581	607	809	943	1 074	1 185	11	15	2.8
Nuclear	132	111	123	307	372	430	469	2	6	5.7
Hydro	45	134	142	167	192	211	227	2	3	2.0
Bioenergy	509	524	532	579	611	645	681	9	8	1.0
Other renewables	27	93	105	256	355	465	582	2	7	7.4
Power generation	**1 029**	**2 265**	**2 331**	**2 851**	**3 172**	**3 457**	**3 704**	**100**	**100**	**1.9**
Coal	599	1 578	1 593	1 682	1 752	1 791	1 816	68	49	0.5
Oil	103	65	63	44	42	34	28	3	1	-3.4
Gas	121	257	271	324	372	419	458	12	12	2.2
Nuclear	132	111	123	307	372	430	469	5	13	5.7
Hydro	45	134	142	167	192	211	227	6	6	2.0
Bioenergy	6	57	64	117	146	177	209	3	6	5.1
Other renewables	23	64	75	209	298	394	499	3	13	8.2
Other energy sector	**311**	**637**	**642**	**670**	**697**	**716**	**733**	**100**	**100**	**0.6**
Electricity	*69*	*143*	*149*	*176*	*199*	*220*	*241*	*23*	*33*	*2.0*
TFC	**2 075**	**3 711**	**3 771**	**4 508**	**4 894**	**5 220**	**5 497**	**100**	**100**	**1.6**
Coal	382	899	881	926	941	948	947	23	17	0.3
Oil	770	1 214	1 246	1 490	1 595	1 664	1 715	33	31	1.3
Gas	102	268	280	439	528	611	684	7	12	3.8
Electricity	298	762	788	1 053	1 214	1 365	1 504	21	27	2.7
Heat	30	89	94	108	111	111	110	3	2	0.6
Bioenergy	489	451	452	445	447	450	454	12	8	0.0
Other renewables	4	28	30	47	58	71	83	1	2	4.3
Industry	**678**	**1 554**	**1 572**	**1 883**	**2 044**	**2 186**	**2 303**	**100**	**100**	**1.6**
Coal	278	717	708	754	779	799	812	45	35	0.6
Oil	133	163	168	181	183	183	181	11	8	0.3
Gas	39	130	136	223	273	321	365	9	16	4.2
Electricity	151	418	429	552	615	672	719	27	31	2.2
Heat	21	59	62	70	69	67	63	4	3	0.1
Bioenergy	55	67	68	102	121	139	154	4	7	3.4
Other renewables	0	0	0	1	3	6	9	0	0	14.2
Transport	**350**	**685**	**696**	**905**	**1 012**	**1 093**	**1 165**	**100**	**100**	**2.2**
Oil	341	631	639	797	874	922	963	92	83	1.7
Electricity	4	19	20	33	44	56	68	3	6	5.2
Biofuels	0	6	7	20	27	34	42	1	4	7.5
Other fuels	5	28	29	54	67	80	93	4	8	4.9
Buildings	**802**	**1 055**	**1 073**	**1 177**	**1 251**	**1 321**	**1 386**	**100**	**100**	**1.1**
Coal	76	103	99	83	71	59	47	9	3	-3.1
Oil	117	137	141	140	137	132	129	13	9	-0.4
Gas	35	89	93	130	151	170	183	9	13	2.8
Electricity	128	290	302	420	502	580	656	28	47	3.3
Heat	9	31	32	38	41	44	47	3	3	1.6
Bioenergy	434	378	376	321	296	272	251	35	18	-1.7
Traditional biomass	*426*	*367*	*365*	*307*	*278*	*253*	*231*	*34*	*17*	*-1.9*
Other renewables	4	27	29	44	53	63	73	3	5	3.9
Other	**246**	**417**	**430**	**544**	**586**	**620**	**643**	**100**	**100**	**1.7**
Petrochem. feedstock	*151*	*237*	*250*	*329*	*359*	*387*	*409*	*23*	*29*	*2.1*

Asia Pacific: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**6 947**	**7 700**	**9 017**	**6 122**	**6 252**	**6 479**	**100**	**100**	**1.9**	**0.5**
Coal	3 177	3 485	4 050	2 429	2 041	1 457	45	22	1.6	-2.6
Oil	1 697	1 841	2 031	1 541	1 519	1 334	23	21	1.5	-0.3
Gas	808	936	1 204	828	980	1 162	13	18	2.9	2.7
Nuclear	306	373	460	345	487	680	5	11	5.7	7.4
Hydro	165	184	212	178	212	264	2	4	1.7	2.6
Bioenergy	567	586	628	457	454	580	7	9	0.7	0.4
Other renewables	226	294	432	343	560	1 001	5	15	6.1	9.9
Power generation	**3 016**	**3 460**	**4 281**	**2 580**	**2 707**	**3 031**	**100**	**100**	**2.6**	**1.1**
Coal	1 884	2 127	2 597	1 262	919	473	61	16	2.1	-4.9
Oil	45	42	29	42	37	25	1	1	-3.2	-3.8
Gas	323	364	457	338	404	461	11	15	2.2	2.2
Nuclear	306	373	460	345	487	680	11	22	5.7	7.4
Hydro	165	184	212	178	212	264	5	9	1.7	2.6
Bioenergy	110	129	166	134	172	255	4	8	4.0	5.9
Other renewables	182	242	361	283	476	874	8	29	6.8	10.8
Other energy sector	**701**	**749**	**838**	**623**	**613**	**581**	**100**	**100**	**1.1**	**-0.4**
Electricity	*191*	*222*	*284*	*162*	*172*	*193*	*34*	*33*	*2.7*	*1.1*
TFC	**4 637**	**5 119**	**5 946**	**4 196**	**4 337**	**4 524**	**100**	**100**	**1.9**	**0.8**
Coal	965	1 007	1 065	869	826	707	18	16	0.8	-0.9
Oil	1 551	1 704	1 922	1 410	1 405	1 260	32	28	1.8	0.0
Gas	437	525	696	446	534	665	12	15	3.9	3.7
Electricity	1 088	1 274	1 624	1 000	1 121	1 364	27	30	3.1	2.3
Heat	113	119	125	104	101	91	2	2	1.2	-0.2
Bioenergy	440	440	442	307	265	308	7	7	-0.1	-1.6
Other renewables	44	52	72	61	84	128	1	3	3.6	6.2
Industry	**1 935**	**2 141**	**2 504**	**1 794**	**1 861**	**1 932**	**100**	**100**	**2.0**	**0.9**
Coal	781	825	897	706	682	610	36	32	1.0	-0.6
Oil	186	191	194	172	166	152	8	8	0.6	-0.4
Gas	224	278	386	221	264	337	15	17	4.5	3.9
Electricity	567	645	786	522	553	604	31	31	2.6	1.4
Heat	74	76	76	68	64	51	3	3	0.9	-0.8
Bioenergy	103	123	159	101	119	152	6	8	3.6	3.4
Other renewables	1	2	4	6	12	25	0	1	11.0	19.3
Transport	**927**	**1 056**	**1 262**	**857**	**906**	**922**	**100**	**100**	**2.5**	**1.2**
Oil	840	952	1 121	733	713	576	89	62	2.4	-0.4
Electricity	26	30	40	33	57	145	3	16	2.9	8.6
Biofuels	14	19	28	33	56	86	2	9	5.7	10.8
Other fuels	47	54	73	57	79	115	6	12	3.9	5.9
Buildings	**1 222**	**1 320**	**1 501**	**1 008**	**997**	**1 049**	**100**	**100**	**1.4**	**-0.1**
Coal	92	86	71	78	60	19	5	2	-1.4	-6.7
Oil	150	150	145	138	133	107	10	10	0.1	-1.2
Gas	134	157	193	135	156	171	13	16	3.1	2.6
Electricity	445	541	729	399	460	561	49	53	3.7	2.6
Heat	39	42	49	36	38	40	3	4	1.7	0.9
Bioenergy	321	294	248	169	83	54	17	5	-1.7	-7.7
Traditional biomass	*307*	*278*	*231*	*153*	*63*	*32*	*15*	*3*	*-1.9*	*-9.6*
Other renewables	42	49	66	53	69	98	4	9	3.4	5.2
Other	**553**	**602**	**679**	**537**	**574**	**621**	**100**	**100**	**1.9**	**1.5**
Petrochem. feedstock	*330*	*364*	*424*	*327*	*355*	*402*	*28*	*38*	*2.2*	*2.0*

Asia Pacific: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**4 262**	**10 497**	**10 852**	**14 277**	**16 390**	**18 371**	**20 200**	**100**	**100**	**2.6**
Coal	2 170	6 357	6 386	7 006	7 375	7 634	7 818	59	39	0.8
Oil	432	258	248	156	140	109	83	2	0	-4.4
Gas	591	1 356	1 428	1 837	2 154	2 467	2 756	13	14	2.8
Nuclear	505	425	470	1 180	1 428	1 651	1 798	4	9	5.7
Renewables	564	2 101	2 319	4 099	5 294	6 510	7 745	21	38	5.2
Hydro	520	1 557	1 654	1 945	2 233	2 458	2 636	15	13	2.0
Bioenergy	18	157	178	365	471	584	703	2	3	5.9
Wind	3	253	318	934	1 295	1 685	2 095	3	10	8.2
Geothermal	23	32	33	61	84	110	138	0	1	6.1
Solar PV	1	101	135	774	1 171	1 607	2 076	1	10	12.1
CSP	-	1	1	18	36	56	80	0	0	21.7
Marine	0	1	1	2	4	9	17	0	0	14.3

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**2 668**	**2 852**	**4 221**	**4 957**	**5 690**	**6 378**	**100**	**100**	**3.4**
Coal	1 287	1 360	1 652	1 767	1 874	1 970	48	31	1.6
Oil	115	116	93	82	68	53	4	1	-3.2
Gas	359	368	535	612	694	768	13	12	3.1
Nuclear	105	112	167	193	220	239	4	4	3.2
Renewables	802	896	1 773	2 304	2 835	3 349	31	53	5.6
Hydro	501	518	651	741	810	862	18	14	2.1
Bioenergy	36	39	69	86	104	123	1	2	4.9
Wind	165	189	456	610	768	922	7	14	6.8
Geothermal	5	5	9	13	16	21	0	0	6.1
Solar PV	94	144	581	841	1 116	1 392	5	22	9.9
CSP	0	0	6	11	16	23	0	0	20.0
Marine	0	0	1	2	3	6	0	0	13.7

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**7 065**	**15 029**	**15 137**	**16 464**	**17 282**	**17 830**	**18 223**	**100**	**100**	**0.8**
Coal	4 190	10 524	10 517	10 919	11 210	11 351	11 405	69	63	0.3
Oil	2 337	3 226	3 275	3 739	3 959	4 074	4 164	22	23	1.0
Gas	539	1 278	1 345	1 807	2 112	2 405	2 655	9	15	2.9
Power generation	**3 115**	**7 284**	**7 371**	**7 777**	**8 140**	**8 365**	**8 512**	**100**	**100**	**0.6**
Coal	2 499	6 472	6 533	6 875	7 134	7 271	7 346	89	86	0.5
Oil	331	201	196	137	128	106	86	3	1	-3.4
Gas	284	611	643	765	877	988	1 080	9	13	2.2
TFC	**3 604**	**7 152**	**7 169**	**8 112**	**8 573**	**8 902**	**9 154**	**100**	**100**	**1.0**
Coal	1 570	3 787	3 723	3 804	3 847	3 864	3 857	52	42	0.1
Oil	1 857	2 828	2 874	3 405	3 638	3 776	3 884	40	42	1.3
Transport	*1 023*	*1 890*	*1 918*	*2 395*	*2 626*	*2 774*	*2 897*	*27*	*32*	*1.7*
Gas	177	537	571	903	1 088	1 262	1 413	8	15	3.8

Asia Pacific: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**14 862**	**17 361**	**22 098**	**13 467**	**14 952**	**17 976**	**100**	**100**	**3.0**	**2.1**
Coal	7 917	9 093	11 427	5 188	3 772	1 851	52	10	2.5	-5.0
Oil	158	142	88	142	116	69	0	0	-4.2	-5.2
Gas	1 824	2 084	2 700	1 895	2 251	2 531	12	14	2.7	2.4
Nuclear	1 175	1 433	1 765	1 323	1 871	2 611	8	15	5.7	7.4
Renewables	3 788	4 609	6 118	4 919	6 942	10 915	28	61	4.1	6.7
Hydro	1 920	2 140	2 460	2 076	2 463	3 066	11	17	1.7	2.6
Bioenergy	343	411	547	427	567	872	2	5	4.8	6.8
Wind	794	1 042	1 551	1 300	1 992	3 267	7	18	6.8	10.2
Geothermal	57	74	110	82	152	280	0	2	5.1	9.3
Solar PV	660	922	1 408	978	1 611	2 951	6	16	10.3	13.7
CSP	12	19	34	53	152	455	0	3	17.4	30.9
Marine	1	2	8	2	6	23	0	0	10.8	15.9

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**4 128**	**4 791**	**5 974**	**4 420**	**5 259**	**6 802**	**100**	**100**	**3.1**	**3.7**
Coal	1 743	1 963	2 397	1 472	1 316	964	40	14	2.4	-1.4
Oil	93	82	55	94	83	53	1	1	-3.1	-3.2
Gas	528	608	759	500	556	741	13	11	3.1	3.0
Nuclear	169	195	235	187	255	348	4	5	3.1	4.8
Renewables	1 596	1 943	2 528	2 168	3 049	4 696	42	69	4.4	7.1
Hydro	640	706	802	703	825	1 008	13	15	1.8	2.8
Bioenergy	65	76	96	80	103	153	2	2	3.8	5.9
Wind	391	495	681	626	915	1 394	11	20	5.5	8.7
Geothermal	9	11	16	13	23	41	0	1	5.1	9.2
Solar PV	488	649	921	728	1 134	1 957	15	29	8.0	11.5
CSP	4	6	10	18	46	135	0	2	15.8	29.3
Marine	0	1	3	1	2	8	0	0	10.2	15.3

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**17 643**	**19 409**	**22 567**	**14 175**	**12 346**	**8 505**	**100**	**100**	**1.7**	**-2.4**
Coal	11 914	13 031	15 106	8 852	6 823	3 341	67	39	1.5	-4.7
Oil	3 926	4 286	4 774	3 478	3 349	2 730	21	32	1.6	-0.8
Gas	1 803	2 092	2 688	1 845	2 173	2 433	12	29	2.9	2.5
Power generation	**8 604**	**9 661**	**11 711**	**6 066**	**4 557**	**1 980**	**100**	**100**	**1.9**	**-5.3**
Coal	7 701	8 672	10 544	5 140	3 499	925	90	47	2.0	-7.8
Oil	139	130	89	129	115	77	1	4	-3.2	-3.8
Gas	764	859	1 077	797	943	978	9	49	2.2	1.8
TFC	**8 439**	**9 139**	**10 223**	**7 587**	**7 326**	**6 166**	**100**	**100**	**1.5**	**-0.6**
Coal	3 962	4 114	4 331	3 497	3 147	2 303	42	37	0.6	-2.0
Oil	3 582	3 948	4 464	3 171	3 078	2 531	44	41	1.9	-0.5
Transport	*2 522*	*2 862*	*3 374*	*2 201*	*2 143*	*1 733*	*33*	*28*	*2.4*	*-0.4*
Gas	896	1 077	1 428	919	1 101	1 332	14	22	3.9	3.6

China: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**1 143**	**2 990**	**3 006**	**3 439**	**3 631**	**3 742**	**3 797**	**100**	**100**	**1.0**
Coal	668	1 992	1 957	1 908	1 873	1 803	1 706	65	45	-0.6
Oil	227	538	552	676	711	716	716	18	19	1.1
Gas	23	160	172	309	374	428	469	6	12	4.3
Nuclear	4	45	56	166	218	261	287	2	8	7.1
Hydro	19	96	102	108	117	125	130	3	3	1.0
Bioenergy	198	114	112	131	149	169	192	4	5	2.3
Other renewables	3	46	55	141	189	240	297	2	8	7.3
Power generation	**380**	**1 272**	**1 303**	**1 558**	**1 700**	**1 805**	**1 871**	**100**	**100**	**1.5**
Coal	334	1 047	1 042	1 034	1 043	1 025	984	80	53	-0.2
Oil	16	7	7	7	6	6	5	1	0	-1.5
Gas	5	34	41	93	112	129	142	3	8	5.3
Nuclear	4	45	56	166	218	261	287	4	15	7.1
Hydro	19	96	102	108	117	125	130	8	7	1.0
Bioenergy	1	23	28	51	64	78	93	2	5	5.1
Other renewables	0	20	27	100	139	182	230	2	12	9.4
Other energy sector	**127**	**406**	**403**	**390**	**385**	**375**	**365**	**100**	**100**	**-0.4**
Electricity	*27*	*83*	*85*	*94*	*100*	*106*	*110*	*21*	*30*	*1.1*
TFC	**791**	**1 915**	**1 924**	**2 281**	**2 421**	**2 505**	**2 557**	**100**	**100**	**1.2**
Coal	274	702	683	639	596	550	498	35	19	-1.3
Oil	186	484	492	626	668	677	683	26	27	1.4
Gas	13	106	111	211	261	303	335	6	13	4.7
Electricity	92	423	437	582	658	721	770	23	30	2.4
Heat	25	83	89	102	104	105	104	5	4	0.7
Bioenergy	197	90	84	80	85	91	99	4	4	0.7
Other renewables	2	26	28	41	49	59	68	1	3	3.7
Industry	**304**	**969**	**972**	**1 077**	**1 113**	**1 132**	**1 131**	**100**	**100**	**0.6**
Coal	185	540	529	484	451	414	374	54	33	-1.4
Oil	35	57	58	57	55	51	47	6	4	-0.9
Gas	4	40	42	93	120	144	163	4	14	5.8
Electricity	60	277	283	359	394	421	439	29	39	1.8
Heat	19	56	59	67	67	65	61	6	5	0.1
Bioenergy	-	-	-	16	25	35	43	-	4	n.a.
Other renewables	0	0	0	1	1	3	5	0	0	13.5
Transport	**91**	**301**	**299**	**426**	**474**	**493**	**513**	**100**	**100**	**2.3**
Oil	85	264	261	355	384	387	391	87	76	1.7
Electricity	1	15	16	26	33	40	46	5	9	4.5
Biofuels	-	2	2	9	14	18	22	1	4	10.4
Other fuels	4	19	20	36	43	48	52	7	10	4.2
Buildings	**316**	**436**	**438**	**497**	**530**	**558**	**581**	**100**	**100**	**1.2**
Coal	61	85	81	66	56	46	37	18	6	-3.2
Oil	20	52	53	53	49	43	38	12	7	-1.3
Gas	4	41	43	71	85	97	105	10	18	3.8
Electricity	26	117	123	180	213	242	268	28	46	3.3
Heat	7	28	29	35	38	40	43	7	7	1.6
Bioenergy	197	88	82	53	42	34	28	19	5	-4.3
Traditional biomass	*197*	*88*	*82*	*51*	*39*	*30*	*23*	*19*	*4*	*-5.2*
Other renewables	2	25	27	40	47	55	62	6	11	3.5
Other	**79**	**209**	**216**	**281**	**304**	**322**	**333**	**100**	**100**	**1.8**
Petrochem. feedstock	*42*	*107*	*118*	*171*	*192*	*211*	*226*	*27*	*39*	*2.7*

China: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						**Shares** (%)		**CAAGR** (%)	
	2025	**2030**	**2040**	**2025**	**2030**	**2040**	**2040**		**2016e-40**	
	Current Policies			**Sustainable Development**			**CPS**	**SDS**	**CPS**	**SDS**
TPED	**3 617**	**3 941**	**4 408**	**3 146**	**3 142**	**3 021**	**100**	**100**	**1.6**	**0.0**
Coal	2 077	2 176	2 300	1 599	1 305	833	52	28	0.7	-3.5
Oil	720	785	840	633	606	482	19	16	1.8	-0.6
Gas	308	378	502	311	395	516	11	17	4.5	4.7
Nuclear	160	204	267	189	288	395	6	13	6.8	8.5
Hydro	107	114	126	114	125	140	3	5	0.9	1.3
Bioenergy	124	136	166	114	151	218	4	7	1.7	2.8
Other renewables	120	148	208	186	273	436	5	14	5.7	9.0
Power generation	**1 660**	**1 878**	**2 229**	**1 388**	**1 422**	**1 500**	**100**	**100**	**2.3**	**0.6**
Coal	1 163	1 276	1 447	780	578	307	65	20	1.4	-5.0
Oil	7	6	5	6	6	5	0	0	-1.5	-1.8
Gas	95	119	161	98	136	197	7	13	5.9	6.7
Nuclear	160	204	267	189	288	395	12	26	6.8	8.5
Hydro	107	114	126	114	125	140	6	9	0.9	1.3
Bioenergy	48	57	75	63	80	111	3	7	4.2	5.9
Other renewables	81	102	148	137	209	345	7	23	7.4	11.3
Other energy sector	**407**	**416**	**428**	**357**	**331**	**277**	**100**	**100**	**0.3**	**-1.5**
Electricity	*99*	*110*	*130*	*85*	*85*	*87*	*30*	*31*	*1.8*	*0.1*
TFC	**2 374**	**2 581**	**2 872**	**2 145**	**2 179**	**2 114**	**100**	**100**	**1.7**	**0.4**
Coal	672	652	596	600	521	349	21	17	-0.6	-2.8
Oil	668	737	802	588	569	462	28	22	2.1	-0.3
Gas	207	257	346	210	260	329	12	16	4.8	4.6
Electricity	605	699	858	548	599	691	30	33	2.8	1.9
Heat	106	112	119	98	95	85	4	4	1.2	-0.2
Bioenergy	76	78	91	51	71	107	3	5	0.3	1.0
Other renewables	39	46	61	49	64	91	2	4	3.2	5.0
Industry	**1 118**	**1 189**	**1 296**	**1 023**	**1 009**	**937**	**100**	**100**	**1.2**	**-0.2**
Coal	507	489	444	453	392	260	34	28	-0.7	-2.9
Oil	60	59	54	54	48	35	4	4	-0.3	-2.0
Gas	93	123	180	94	121	164	14	17	6.3	5.8
Electricity	372	419	500	340	355	371	39	40	2.4	1.1
Heat	71	74	74	65	61	49	6	5	1.0	-0.8
Bioenergy	15	24	42	15	26	46	3	5	n.a.	n.a.
Other renewables	0	0	2	3	6	12	0	1	8.4	18.0
Transport	**440**	**499**	**562**	**403**	**421**	**400**	**100**	**100**	**2.7**	**1.2**
Oil	384	433	478	327	306	209	85	52	2.5	-0.9
Electricity	20	22	28	25	39	85	5	21	2.3	7.2
Biofuels	7	10	16	14	26	39	3	10	8.8	13.1
Other fuels	30	33	41	37	49	67	7	17	3.1	5.2
Buildings	**528**	**576**	**651**	**443**	**456**	**461**	**100**	**100**	**1.7**	**0.2**
Coal	74	69	56	62	46	12	9	3	-1.5	-7.6
Oil	59	58	47	49	41	21	7	5	-0.5	-3.7
Gas	73	88	109	68	77	86	17	19	4.0	2.9
Electricity	196	238	310	168	189	219	48	47	3.9	2.4
Heat	35	39	44	33	34	36	7	8	1.8	0.9
Bioenergy	52	41	26	19	13	11	4	2	-4.6	-8.1
Traditional biomass	*51*	*39*	*23*	*16*	*9*	*4*	*4*	*1*	*-5.2*	*-11.4*
Other renewables	38	45	58	45	56	76	9	16	3.2	4.4
Other	**288**	**317**	**363**	**275**	**294**	**316**	**100**	**100**	**2.2**	**1.6**
Petrochem. feedstock	*173*	*198*	*242*	*168*	*187*	*216*	*37*	*47*	*3.0*	*2.6*

China: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**1 387**	**5 882**	**6 079**	**7 887**	**8 838**	**9 621**	**10 231**	**100**	**100**	**2.2**
Coal	1 079	4 134	4 080	4 171	4 232	4 174	4 008	67	39	-0.1
Oil	47	10	10	6	6	5	3	0	0	-4.6
Gas	18	158	198	525	642	747	832	3	8	6.2
Nuclear	17	171	213	635	835	1 002	1 102	4	11	7.1
Renewables	226	1 409	1 577	2 549	3 122	3 693	4 285	26	42	4.3
Hydro	222	1 114	1 191	1 251	1 359	1 448	1 513	20	15	1.0
Bioenergy	2	64	77	161	209	259	311	1	3	6.0
Wind	1	186	242	685	907	1 129	1 356	4	13	7.4
Geothermal	0	0	0	1	3	7	14	0	0	20.2
Solar PV	0	45	66	436	615	806	1 031	1	10	12.1
CSP	-	0	0	15	29	44	58	0	1	39.3
Marine	0	0	0	0	1	1	2	0	0	24.6

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**1 507**	**1 626**	**2 406**	**2 761**	**3 075**	**3 348**	**100**	**100**	**3.1**
Coal	900	945	1 061	1 089	1 096	1 087	58	32	0.6
Oil	9	9	8	8	7	4	1	0	-3.0
Gas	67	67	145	173	199	219	4	7	5.0
Nuclear	29	34	86	111	132	145	2	4	6.3
Renewables	503	571	1 107	1 380	1 641	1 892	35	57	5.1
Hydro	320	332	400	440	471	493	20	15	1.7
Bioenergy	11	12	25	33	41	49	1	1	5.9
Wind	129	149	336	429	515	593	9	18	5.9
Geothermal	0	0	0	0	1	2	0	0	19.5
Solar PV	43	77	340	469	600	738	5	22	9.8
CSP	0	0	5	9	13	16	0	0	28.0
Marine	0	0	0	0	0	1	0	0	23.7

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**3 127**	**9 056**	**8 973**	**9 199**	**9 212**	**8 990**	**8 633**	**100**	**100**	**-0.2**
Coal	2 537	7 405	7 307	6 920	6 713	6 384	5 947	81	69	-0.9
Oil	548	1 295	1 285	1 557	1 620	1 594	1 570	14	18	0.8
Gas	43	356	380	722	879	1 011	1 115	4	13	4.6
Power generation	**1 449**	**4 395**	**4 394**	**4 478**	**4 544**	**4 493**	**4 337**	**100**	**100**	**-0.1**
Coal	1 382	4 291	4 272	4 236	4 258	4 170	3 985	97	92	-0.3
Oil	56	24	25	22	22	20	17	1	0	-1.5
Gas	12	79	97	220	264	303	335	2	8	5.3
TFC	**1 529**	**4 324**	**4 243**	**4 411**	**4 368**	**4 213**	**4 026**	**100**	**100**	**-0.2**
Coal	1 071	2 923	2 849	2 523	2 305	2 077	1 839	67	46	-1.8
Oil	439	1 176	1 162	1 443	1 510	1 490	1 472	27	37	1.0
Transport	*258*	*795*	*786*	*1 068*	*1 156*	*1 166*	*1 179*	*19*	*29*	*1.7*
Gas	19	226	232	445	553	645	715	5	18	4.8

China: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**8 224**	**9 433**	**11 485**	**7 370**	**7 938**	**8 973**	**100**	**100**	**2.7**	**1.6**
Coal	4 771	5 333	6 227	3 094	2 267	1 127	54	13	1.8	-5.2
Oil	6	6	3	5	4	2	0	0	-4.6	-6.4
Gas	524	658	901	499	650	903	8	10	6.5	6.5
Nuclear	613	784	1 024	724	1 104	1 517	9	17	6.8	8.5
Renewables	2 309	2 652	3 329	3 047	3 913	5 424	29	60	3.2	5.3
Hydro	1 241	1 323	1 469	1 328	1 454	1 630	13	18	0.9	1.3
Bioenergy	152	184	247	205	264	366	2	4	5.0	6.7
Wind	559	688	968	953	1 310	1 914	8	21	5.9	9.0
Geothermal	1	2	8	1	4	19	0	0	17.2	21.7
Solar PV	346	440	610	512	749	1 214	5	14	9.7	12.9
CSP	10	15	25	48	132	279	0	3	34.5	48.7
Marine	0	0	2	0	1	2	0	0	23.4	25.1

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**2 320**	**2 623**	**3 098**	**2 531**	**2 868**	**3 385**	**100**	**100**	**2.7**	**3.1**
Coal	1 123	1 218	1 348	964	846	629	44	19	1.5	-1.7
Oil	8	8	4	8	8	4	0	0	-3.0	-3.0
Gas	144	176	234	131	158	229	8	7	5.3	5.2
Nuclear	83	105	135	100	149	199	4	6	6.0	7.7
Renewables	963	1 117	1 376	1 329	1 708	2 324	44	69	3.7	6.0
Hydro	395	424	477	431	476	536	15	16	1.5	2.0
Bioenergy	24	29	39	32	42	58	1	2	4.8	6.6
Wind	276	329	422	457	600	814	14	24	4.4	7.3
Geothermal	0	0	1	0	1	3	0	0	16.6	21.0
Solar PV	265	330	430	392	550	835	14	25	7.4	10.4
CSP	3	5	7	16	39	76	0	2	23.8	36.5
Marine	0	0	1	0	0	1	0	0	22.5	24.2

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**9 994**	**10 618**	**11 364**	**7 802**	**6 319**	**3 309**	**100**	**100**	**1.0**	**-4.1**
Coal	7 591	7 905	8 271	5 645	4 095	1 336	73	40	0.5	-6.8
Oil	1 684	1 826	1 906	1 432	1 309	879	17	27	1.7	-1.6
Gas	719	886	1 187	724	914	1 094	10	33	4.9	4.5
Power generation	**5 012**	**5 516**	**6 287**	**3 436**	**2 479**	**820**	**100**	**100**	**1.5**	**-6.8**
Coal	4 766	5 215	5 890	3 185	2 147	430	94	52	1.3	-9.1
Oil	22	22	17	21	20	16	0	2	-1.5	-1.8
Gas	224	279	380	230	313	374	6	46	5.9	5.8
TFC	**4 654**	**4 773**	**4 752**	**4 094**	**3 611**	**2 335**	**100**	**100**	**0.5**	**-2.5**
Coal	2 656	2 527	2 229	2 319	1 840	846	47	36	-1.0	-4.9
Oil	1 564	1 706	1 792	1 332	1 221	818	38	35	1.8	-1.5
Transport	*1 156*	*1 305*	*1 438*	*985*	*923*	*630*	*30*	*27*	*2.6*	*-0.9*
Gas	435	541	730	444	550	672	15	29	4.9	4.5

India: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**441**	**851**	**897**	**1 228**	**1 466**	**1 694**	**1 901**	**100**	**100**	**3.2**
Coal	146	379	402	560	667	768	860	45	45	3.2
Oil	112	206	222	300	357	409	450	25	24	3.0
Gas	23	43	47	83	108	132	157	5	8	5.2
Nuclear	4	10	10	29	44	58	72	1	4	8.7
Hydro	6	12	11	18	24	28	32	1	2	4.4
Bioenergy	149	196	200	206	211	215	218	22	11	0.4
Other renewables	0	5	6	32	55	83	112	1	6	13.2
Power generation	**133**	**316**	**339**	**480**	**586**	**688**	**785**	**100**	**100**	**3.6**
Coal	103	254	274	340	384	427	464	81	59	2.2
Oil	9	8	8	10	11	9	7	2	1	-0.5
Gas	9	14	15	29	41	50	61	4	8	6.0
Nuclear	4	10	10	29	44	58	72	3	9	8.7
Hydro	6	12	11	18	24	28	32	3	4	4.4
Bioenergy	1	15	16	26	31	37	43	5	5	4.2
Other renewables	0	4	5	29	51	78	106	1	14	13.6
Other energy sector	**41**	**76**	**81**	**110**	**134**	**156**	**177**	**100**	**100**	**3.3**
Electricity	*17*	*31*	*33*	*45*	*56*	*68*	*79*	*41*	*45*	*3.8*
TFC	**315**	**578**	**605**	**843**	**1 012**	**1 178**	**1 327**	**100**	**100**	**3.3**
Coal	35	108	111	184	233	280	325	18	24	4.6
Oil	94	174	188	268	325	380	424	31	32	3.4
Gas	10	29	31	52	66	80	93	5	7	4.7
Electricity	32	88	94	161	210	260	309	16	23	5.1
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	144	177	180	176	175	173	170	30	13	-0.2
Other renewables	0	1	1	2	3	5	6	0	0	9.0
Industry	**83**	**208**	**216**	**350**	**437**	**520**	**596**	**100**	**100**	**4.3**
Coal	26	94	96	171	221	270	317	45	53	5.1
Oil	17	24	26	36	42	47	52	12	9	2.9
Gas	2	19	21	33	39	44	48	10	8	3.5
Electricity	14	39	41	69	87	104	120	19	20	4.5
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	26	31	32	42	48	53	57	15	10	2.4
Other renewables	0	0	0	0	1	2	2	0	0	17.6
Transport	**32**	**86**	**92**	**148**	**194**	**243**	**286**	**100**	**100**	**4.8**
Oil	31	82	88	134	172	211	242	95	85	4.3
Electricity	1	1	2	3	6	9	14	2	5	9.5
Biofuels	0	0	1	3	4	6	8	1	3	12.1
Other fuels	0	2	3	7	11	17	23	3	8	9.6
Buildings	**158**	**224**	**231**	**248**	**269**	**291**	**311**	**100**	**100**	**1.3**
Coal	9	14	14	13	12	11	8	6	3	-2.3
Oil	19	30	33	37	40	44	47	14	15	1.5
Gas	0	1	2	4	5	7	9	1	3	7.5
Electricity	11	32	34	63	87	113	138	15	44	6.0
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	119	145	148	131	122	114	105	64	34	-1.4
Traditional biomass	*113*	*139*	*141*	*122*	*114*	*105*	*96*	*61*	*31*	*-1.6*
Other renewables	0	1	1	2	2	3	4	0	1	7.1
Other	**42**	**60**	**65**	**97**	**112**	**124**	**134**	**100**	**100**	**3.0**
Petrochem. feedstock	*20*	*20*	*23*	*36*	*43*	*50*	*55*	*10*	*18*	*3.8*

India: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**1 275**	**1 544**	**2 073**	**1 118**	**1 236**	**1 479**	**100**	**100**	**3.6**	**2.1**
Coal	607	751	1 060	463	456	409	51	28	4.1	0.1
Oil	310	376	492	293	331	348	24	24	3.4	1.9
Gas	80	100	139	102	135	203	7	14	4.6	6.3
Nuclear	25	34	52	28	59	116	3	8	7.3	10.9
Hydro	18	23	29	19	26	38	1	3	4.0	5.2
Bioenergy	205	208	210	168	142	167	10	11	0.2	-0.8
Other renewables	31	51	91	45	87	199	4	13	12.2	15.9
Power generation	**515**	**640**	**904**	**427**	**481**	**605**	**100**	**100**	**4.2**	**2.4**
Coal	382	459	643	256	204	89	71	15	3.6	-4.6
Oil	10	11	7	10	11	7	1	1	-0.3	-0.6
Gas	27	36	50	46	64	111	6	18	5.2	8.7
Nuclear	25	34	52	28	59	116	6	19	7.3	10.9
Hydro	18	23	29	19	26	38	3	6	4.0	5.2
Bioenergy	25	29	36	28	36	59	4	10	3.4	5.6
Other renewables	29	49	86	41	80	186	10	31	12.7	16.3
Other energy sector	**119**	**147**	**201**	**104**	**121**	**147**	**100**	**100**	**3.9**	**2.6**
Electricity	*53*	*67*	*98*	*41*	*49*	*65*	*49*	*44*	*4.7*	*2.9*
TFC	**858**	**1 040**	**1 385**	**781**	**881**	**1 079**	**100**	**100**	**3.5**	**2.4**
Coal	188	242	342	172	206	258	25	24	4.8	3.6
Oil	277	342	465	261	300	328	34	30	3.8	2.3
Gas	51	63	87	55	69	89	6	8	4.4	4.5
Electricity	165	216	320	154	197	287	23	27	5.2	4.8
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	175	174	167	135	102	103	12	10	-0.3	-2.3
Other renewables	2	3	5	4	7	13	0	1	7.8	12.3
Industry	**356**	**447**	**612**	**336**	**400**	**505**	**100**	**100**	**4.4**	**3.6**
Coal	174	227	329	159	195	253	54	50	5.3	4.1
Oil	37	44	54	36	40	48	9	10	3.1	2.6
Gas	32	37	45	33	39	46	7	9	3.2	3.4
Electricity	69	88	122	64	76	96	20	19	4.6	3.6
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	43	50	60	43	48	56	10	11	2.7	2.4
Other renewables	0	1	2	1	3	6	0	1	16.4	22.3
Transport	**150**	**200**	**305**	**140**	**173**	**226**	**100**	**100**	**5.1**	**3.8**
Oil	139	185	275	123	143	151	90	67	4.9	2.3
Electricity	3	4	7	3	9	36	2	16	6.5	14.1
Biofuels	1	1	3	5	11	22	1	10	7.4	16.9
Other fuels	7	10	20	7	11	16	7	7	9.1	8.1
Buildings	**254**	**278**	**329**	**209**	**198**	**219**	**100**	**100**	**1.5**	**-0.2**
Coal	15	14	12	13	11	6	4	3	-0.7	-3.7
Oil	38	42	51	41	48	49	16	22	1.9	1.7
Gas	4	5	9	6	9	13	3	6	7.3	9.2
Electricity	65	92	149	61	83	121	45	55	6.3	5.4
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	131	122	105	86	42	25	32	11	-1.4	-7.2
Traditional biomass	*122*	*114*	*96*	*78*	*33*	*16*	*29*	*7*	*-1.6*	*-8.6*
Other renewables	1	2	3	3	4	7	1	3	5.8	9.4
Other	**98**	**115**	**139**	**96**	**110**	**130**	**100**	**100**	**3.2**	**2.9**
Petrochem. feedstock	*36*	*43*	*55*	*37*	*44*	*56*	*17*	*26*	*3.7*	*3.9*

India: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**570**	**1 383**	**1 476**	**2 383**	**3 075**	**3 784**	**4 480**	**100**	**100**	**4.7**
Coal	390	1 042	1 123	1 470	1 691	1 919	2 116	76	47	2.7
Oil	29	23	23	29	33	28	22	2	0	-0.2
Gas	56	68	75	162	237	300	372	5	8	6.9
Nuclear	17	37	37	110	169	223	276	3	6	8.7
Renewables	77	213	217	612	945	1 314	1 695	15	38	8.9
Hydro	74	137	133	213	276	325	373	9	8	4.4
Bioenergy	1	27	29	61	82	103	124	2	3	6.3
Wind	2	43	49	154	240	346	458	3	10	9.8
Geothermal	-	-	-	0	1	1	2	-	0	n.a.
Solar PV	0	6	7	182	342	530	723	0	16	21.7
CSP	-	1	1	2	4	8	14	0	0	13.5
Marine	-	-	-	-	0	0	1	-	0	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**320**	**349**	**693**	**932**	**1 209**	**1 484**	**100**	**100**	**6.2**
Coal	194	213	326	388	466	542	61	36	4.0
Oil	8	8	11	13	12	10	2	1	0.9
Gas	29	29	59	74	91	111	8	7	5.8
Nuclear	6	7	16	24	32	39	2	3	7.5
Renewables	84	93	281	433	608	783	27	53	9.3
Hydro	46	47	68	84	97	108	13	7	3.6
Bioenergy	8	8	14	17	20	24	2	2	4.6
Wind	25	29	83	124	174	224	8	15	8.9
Geothermal	-	-	0	0	0	0	-	0	n.a.
Solar PV	5	9	116	207	314	422	3	28	17.4
CSP	0	0	1	1	3	5	0	0	13.5
Marine	-	-	-	0	0	0	-	0	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**890**	**2 065**	**2 214**	**3 101**	**3 717**	**4 302**	**4 825**	**100**	**100**	**3.3**
Coal	577	1 495	1 585	2 190	2 598	2 987	3 338	72	69	3.2
Oil	277	498	534	736	889	1 032	1 151	24	24	3.3
Gas	36	72	95	174	230	283	336	4	7	5.4
Power generation	**459**	**1 065**	**1 149**	**1 449**	**1 656**	**1 843**	**2 009**	**100**	**100**	**2.4**
Coal	409	1 009	1 089	1 351	1 527	1 698	1 844	95	92	2.2
Oil	28	24	25	30	33	27	22	2	1	-0.5
Gas	22	32	35	69	96	118	144	3	7	6.0
TFC	**399**	**963**	**1 027**	**1 606**	**2 011**	**2 403**	**2 753**	**100**	**100**	**4.2**
Coal	164	483	493	834	1 063	1 280	1 485	48	54	4.7
Oil	230	441	475	670	818	963	1 081	46	39	3.5
Transport	*95*	*249*	*267*	*407*	*524*	*641*	*737*	*26*	*27*	*4.3*
Gas	5	38	58	102	130	160	187	6	7	5.0

India: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**2 527**	**3 279**	**4 817**	**2 264**	**2 847**	**4 069**	**100**	**100**	**5.1**	**4.3**
Coal	1 641	1 995	2 845	1 111	911	399	59	10	3.9	-4.2
Oil	30	34	23	30	33	22	0	1	0.0	-0.3
Gas	155	214	320	263	382	703	7	17	6.2	9.8
Nuclear	95	131	201	107	227	444	4	11	7.3	10.9
Renewables	607	905	1 426	755	1 294	2 502	30	61	8.2	10.7
Hydro	214	271	342	223	306	446	7	11	4.0	5.2
Bioenergy	59	75	101	69	98	183	2	4	5.4	8.0
Wind	153	233	386	191	339	664	8	16	9.0	11.5
Geothermal	0	0	1	1	2	5	0	0	n.a.	n.a.
Solar PV	179	323	592	268	533	1 040	12	26	20.7	23.5
CSP	1	2	4	3	16	163	0	4	7.7	25.6
Marine	-	-	1	0	0	1	0	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**694**	**933**	**1 398**	**724**	**1 018**	**1 616**	**100**	**100**	**6.0**	**6.6**
Coal	335	416	616	269	262	204	44	13	4.5	-0.2
Oil	11	14	10	11	13	10	1	1	1.1	0.8
Gas	53	68	93	62	86	188	7	12	5.0	8.1
Nuclear	14	19	29	16	33	63	2	4	6.3	9.7
Renewables	279	416	649	366	623	1 151	46	71	8.4	11.1
Hydro	68	81	97	72	94	132	7	8	3.1	4.4
Bioenergy	13	16	20	15	20	34	1	2	3.8	6.2
Wind	83	120	186	104	174	314	13	19	8.1	10.5
Geothermal	0	0	0	0	0	1	0	0	n.a.	n.a.
Solar PV	115	198	345	174	329	614	25	38	16.4	19.2
CSP	0	1	1	1	6	56	0	3	7.5	25.7
Marine	-	-	0	0	0	0	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**3 307**	**4 087**	**5 695**	**2 717**	**2 798**	**2 621**	**100**	**100**	**4.0**	**0.7**
Coal	2 377	2 933	4 122	1 787	1 705	1 349	72	51	4.1	-0.7
Oil	764	944	1 279	712	805	836	22	32	3.7	1.9
Gas	166	210	294	219	289	436	5	17	4.8	6.5
Power generation	**1 611**	**1 941**	**2 696**	**1 156**	**991**	**564**	**100**	**100**	**3.6**	**-2.9**
Coal	1 517	1 824	2 555	1 018	807	281	95	50	3.6	-5.5
Oil	30	34	23	30	33	21	1	4	-0.3	-0.6
Gas	64	84	118	107	151	261	4	46	5.2	8.7
TFC	**1 650**	**2 095**	**2 932**	**1 518**	**1 766**	**2 016**	**100**	**100**	**4.5**	**2.9**
Coal	854	1 101	1 557	763	892	1 061	53	53	4.9	3.2
Oil	696	870	1 204	647	740	786	41	39	4.0	2.1
Transport	*424*	*562*	*838*	*376*	*435*	*461*	*29*	*23*	*4.9*	*2.3*
Gas	100	123	171	108	134	169	6	8	4.6	4.5

Japan: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**518**	**430**	**431**	**414**	**402**	**392**	**384**	**100**	**100**	**-0.5**
Coal	97	117	118	104	96	88	81	27	21	-1.5
Oil	255	185	179	143	126	112	100	41	26	-2.4
Gas	66	100	104	80	84	89	90	24	23	-0.6
Nuclear	84	2	4	53	56	58	61	1	16	11.8
Hydro	7	7	7	8	8	9	9	2	2	0.8
Bioenergy	5	11	12	14	14	14	14	3	4	0.6
Other renewables	4	6	7	12	17	23	29	2	8	5.8
Power generation	**229**	**185**	**186**	**192**	**195**	**198**	**202**	**100**	**100**	**0.3**
Coal	48	70	69	58	53	49	46	37	23	-1.7
Oil	36	20	17	8	6	3	2	9	1	-8.5
Gas	49	72	74	44	46	48	48	40	24	-1.8
Nuclear	84	2	4	53	56	58	61	2	30	11.8
Hydro	7	7	7	8	8	9	9	4	4	0.8
Bioenergy	2	8	8	9	10	10	10	5	5	0.5
Other renewables	3	6	7	12	16	21	27	4	13	5.8
Other energy sector	**54**	**42**	**43**	**41**	**39**	**36**	**34**	**100**	**100**	**-1.0**
Electricity	*10*	*7*	*7*	*8*	*8*	*8*	*8*	*17*	*23*	*0.2*
TFC	**328**	**291**	**293**	**271**	**260**	**250**	**241**	**100**	**100**	**-0.8**
Coal	24	24	24	22	21	19	17	8	7	-1.4
Oil	194	152	150	126	114	103	94	51	39	-1.9
Gas	22	29	32	35	37	38	38	11	16	0.7
Electricity	83	82	82	82	83	84	85	28	35	0.2
Heat	1	1	1	1	1	1	1	0	0	0.1
Bioenergy	3	3	4	4	4	4	4	1	2	0.7
Other renewables	1	1	0	1	1	2	2	0	1	6.1
Industry	**100**	**87**	**88**	**85**	**80**	**76**	**73**	**100**	**100**	**-0.8**
Coal	24	23	23	22	20	18	17	26	23	-1.4
Oil	32	23	23	20	17	15	13	26	18	-2.3
Gas	8	11	12	14	15	15	15	14	20	0.8
Electricity	34	26	26	25	24	24	24	30	32	-0.5
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	3	3	4	4	4	4	4	4	6	0.7
Other renewables	-	-	-	0	0	0	0	-	1	n.a.
Transport	**84**	**71**	**71**	**58**	**53**	**49**	**46**	**100**	**100**	**-1.8**
Oil	83	70	69	55	49	44	41	98	89	-2.2
Electricity	2	2	2	2	3	3	4	2	8	3.8
Biofuels	-	-	-	-	-	-	-	-	-	n.a.
Other fuels	0	0	0	1	1	1	1	0	3	12.2
Buildings	**101**	**98**	**99**	**98**	**97**	**97**	**97**	**100**	**100**	**-0.1**
Coal	1	0	0	0	0	0	0	0	0	-1.8
Oil	38	25	25	21	19	17	15	25	15	-2.0
Gas	14	18	19	20	21	22	22	20	23	0.5
Electricity	47	54	54	55	56	57	58	54	60	0.3
Heat	1	1	1	1	1	1	1	1	1	0.1
Bioenergy	0	0	0	0	0	0	0	0	0	-0.7
Traditional biomass	-	-	-	-	-	-	-	-	-	*n.a.*
Other renewables	1	0	0	1	1	1	2	0	2	5.6
Other	**42**	**35**	**34**	**31**	**29**	**27**	**26**	**100**	**100**	**-1.2**
Petrochem. feedstock	*33*	*30*	*28*	*26*	*24*	*23*	*21*	*29*	*22*	*-1.2*

Japan: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**419**	**413**	**400**	**379**	**347**	**316**	**100**	**100**	**-0.3**	**-1.3**
Coal	112	112	103	82	53	34	26	11	-0.6	-5.1
Oil	145	131	109	130	105	74	27	23	-2.0	-3.6
Gas	82	83	92	74	74	48	23	15	-0.5	-3.2
Nuclear	48	48	46	55	63	77	12	24	10.5	12.9
Hydro	8	8	9	8	10	13	2	4	0.6	2.3
Bioenergy	13	13	14	14	15	18	3	6	0.5	1.7
Other renewables	12	17	28	17	26	53	7	17	5.6	8.6
Power generation	**195**	**201**	**207**	**172**	**163**	**167**	**100**	**100**	**0.5**	**-0.4**
Coal	65	69	67	39	15	4	32	3	-0.1	-10.8
Oil	8	6	3	5	2	0	1	0	-7.4	-13.7
Gas	46	44	48	41	40	14	23	8	-1.7	-6.8
Nuclear	48	48	46	55	63	77	22	46	10.5	12.9
Hydro	8	8	9	8	10	13	4	8	0.6	2.3
Bioenergy	9	9	9	10	11	13	4	7	0.2	1.7
Other renewables	12	16	26	14	22	47	13	28	5.7	8.3
Other energy sector	**41**	**39**	**35**	**38**	**35**	**28**	**100**	**100**	**-0.8**	**-1.8**
Electricity	*8*	*8*	*8*	*7*	*6*	*6*	*23*	*21*	*0.5*	*-1.0*
TFC	**275**	**267**	**254**	**252**	**229**	**200**	**100**	**100**	**-0.6**	**-1.6**
Coal	22	21	17	21	18	14	7	7	-1.3	-2.2
Oil	128	118	102	116	97	70	40	35	-1.6	-3.1
Gas	36	37	40	32	32	31	16	15	0.9	-0.2
Electricity	84	85	88	76	73	73	35	36	0.3	-0.5
Heat	1	1	1	0	0	0	0	0	0.3	-0.3
Bioenergy	4	4	4	4	5	5	2	3	1.0	1.8
Other renewables	1	1	1	3	4	6	1	3	4.5	11.4
Industry	**85**	**82**	**75**	**81**	**75**	**64**	**100**	**100**	**-0.7**	**-1.3**
Coal	22	20	17	20	18	14	22	21	-1.3	-2.2
Oil	20	18	14	19	16	11	18	17	-2.1	-3.0
Gas	14	15	16	14	14	13	21	21	1.1	0.3
Electricity	25	25	24	24	23	21	32	33	-0.4	-0.9
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	4	4	4	4	4	4	6	6	1.0	0.7
Other renewables	0	0	0	0	1	1	0	2	n.a.	n.a.
Transport	**59**	**55**	**51**	**53**	**45**	**36**	**100**	**100**	**-1.4**	**-2.8**
Oil	57	52	47	50	40	27	93	75	-1.6	-3.9
Electricity	2	2	3	2	4	7	6	19	2.7	6.2
Biofuels	-	-	-	0	1	1	-	3	n.a.	n.a.
Other fuels	0	0	0	0	1	1	1	4	7.5	12.1
Buildings	**100**	**101**	**103**	**87**	**81**	**75**	**100**	**100**	**0.1**	**-1.2**
Coal	0	0	0	0	0	0	0	0	-1.3	-5.8
Oil	21	19	16	17	14	8	15	11	-1.8	-4.4
Gas	21	22	24	18	17	16	23	22	0.8	-0.8
Electricity	56	58	61	49	46	45	60	60	0.5	-0.8
Heat	1	1	1	0	0	0	1	1	0.3	-0.3
Bioenergy	0	0	0	0	0	0	0	0	-0.7	-0.7
Traditional biomass	-	-	-	-	-	-	-	-	*n.a.*	*n.a.*
Other renewables	1	1	1	2	3	5	1	7	4.4	11.2
Other	**31**	**29**	**26**	**31**	**29**	**25**	**100**	**100**	**-1.2**	**-1.3**
Petrochem. feedstock	*26*	*24*	*21*	*26*	*24*	*21*	*21*	*28*	*-1.2*	*-1.2*

Japan: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**1 088**	**1 035**	**1 043**	**1 040**	**1 052**	**1 066**	**1 080**	**100**	**100**	**0.1**
Coal	234	343	339	291	270	251	236	33	22	-1.5
Oil	179	103	85	42	31	19	11	8	1	-8.2
Gas	254	410	418	272	287	304	303	40	28	-1.3
Nuclear	322	9	16	205	216	222	233	2	22	11.8
Renewables	99	170	184	231	248	270	296	18	27	2.0
Hydro	85	85	86	91	95	99	104	8	10	0.8
Bioenergy	10	41	44	48	48	48	48	4	4	0.4
Wind	0	5	6	14	20	26	32	1	3	7.3
Geothermal	3	3	3	5	9	14	19	0	2	8.1
Solar PV	0	36	46	72	75	81	87	4	8	2.7
CSP	-	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	0	1	2	7	-	1	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**312**	**323**	**330**	**327**	**328**	**332**	**100**	**100**	**0.1**
Coal	50	50	48	48	45	41	15	12	-0.8
Oil	44	44	24	14	9	5	14	2	-8.5
Gas	82	85	91	94	94	92	26	28	0.3
Nuclear	42	41	34	31	30	32	13	10	-1.1
Renewables	94	103	133	140	150	161	32	49	1.9
Hydro	50	50	51	52	54	55	15	16	0.4
Bioenergy	7	7	9	10	10	10	2	3	1.5
Wind	3	3	7	9	11	13	1	4	6.2
Geothermal	1	1	1	2	2	3	0	1	7.9
Solar PV	34	42	65	68	73	78	13	24	2.6
CSP	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	0	0	1	3	-	1	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**1 140**	**1 131**	**1 130**	**914**	**850**	**793**	**742**	**100**	**100**	**-1.7**
Coal	371	458	460	402	371	341	317	41	43	-1.5
Oil	603	426	414	319	279	244	217	37	29	-2.7
Gas	166	247	256	192	200	208	208	23	28	-0.9
Power generation	**460**	**555**	**543**	**394**	**370**	**349**	**330**	**100**	**100**	**-2.1**
Coal	231	315	311	260	240	221	207	57	63	-1.7
Oil	114	64	53	25	18	11	6	10	2	-8.5
Gas	115	176	179	108	112	118	117	33	35	-1.8
TFC	**633**	**525**	**535**	**475**	**440**	**407**	**378**	**100**	**100**	**-1.4**
Coal	119	114	119	113	104	95	87	22	23	-1.3
Oil	463	342	342	280	250	223	202	64	53	-2.2
Transport	*248*	*208*	*205*	*165*	*147*	*132*	*121*	*38*	*32*	*-2.2*
Gas	51	68	74	82	86	88	89	14	23	0.7

Japan: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**1 061**	**1 082**	**1 123**	**956**	**922**	**913**	**100**	**100**	**0.3**	**-0.6**
Coal	329	351	347	199	75	19	31	2	0.1	-11.3
Oil	42	31	14	28	11	3	1	0	-7.2	-13.7
Gas	282	274	310	255	261	85	28	9	-1.2	-6.4
Nuclear	182	185	176	210	243	295	16	32	10.5	12.9
Renewables	226	241	276	264	333	511	25	56	1.7	4.3
Hydro	91	93	100	99	116	147	9	16	0.6	2.3
Bioenergy	47	46	46	49	54	63	4	7	0.2	1.5
Wind	13	18	30	23	50	125	3	14	7.1	13.6
Geothermal	5	10	19	5	11	27	2	3	8.3	9.9
Solar PV	70	73	79	87	101	138	7	15	2.3	4.7
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	0	1	0	1	11	0	1	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**332**	**331**	**330**	**334**	**340**	**379**	**100**	**100**	**0.1**	**0.7**
Coal	51	53	52	45	32	8	16	2	0.2	-7.6
Oil	24	14	7	24	14	5	2	1	-7.5	-8.8
Gas	93	99	98	76	70	56	30	15	0.6	-1.7
Nuclear	34	29	24	34	35	40	7	11	-2.2	-0.1
Renewables	130	136	149	156	190	270	45	71	1.6	4.1
Hydro	51	52	53	55	62	73	16	19	0.2	1.6
Bioenergy	9	9	10	9	11	12	3	3	1.3	2.3
Wind	6	8	12	11	21	48	4	13	5.9	12.2
Geothermal	1	2	3	1	2	5	1	1	8.0	9.6
Solar PV	63	65	71	79	94	128	21	34	2.2	4.8
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	0	0	0	0	4	0	1	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**959**	**932**	**870**	**764**	**569**	**337**	**100**	**100**	**-1.1**	**-4.9**
Coal	437	444	413	306	177	92	47	27	-0.4	-6.5
Oil	325	291	243	281	218	143	28	42	-2.2	-4.3
Gas	197	197	214	177	174	102	25	30	-0.8	-3.8
Power generation	**432**	**438**	**428**	**292**	**164**	**33**	**100**	**100**	**-1.0**	**-11.1**
Coal	295	312	302	176	60	2	70	6	-0.1	-19.0
Oil	25	18	8	17	7	2	2	5	-7.4	-13.7
Gas	112	108	118	99	97	29	28	89	-1.7	-7.3
TFC	**482**	**453**	**407**	**430**	**369**	**277**	**100**	**100**	**-1.1**	**-2.7**
Coal	113	105	88	104	93	71	22	26	-1.3	-2.2
Oil	286	262	226	251	202	134	55	49	-1.7	-3.8
Transport	*169*	*156*	*140*	*149*	*118*	*79*	*35*	*29*	*-1.6*	*-3.9*
Gas	83	87	93	75	74	72	23	26	0.9	-0.1

Southeast Asia: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**385**	**623**	**643**	**806**	**892**	**977**	**1 062**	**100**	**100**	**2.1**
Coal	32	109	112	176	208	237	271	17	26	3.7
Oil	156	212	220	270	288	301	308	34	29	1.4
Gas	74	140	141	162	180	203	225	22	21	2.0
Nuclear	-	-	-	-	-	1	4	-	0	n.a.
Hydro	4	9	11	17	23	27	30	2	3	4.4
Bioenergy	101	126	129	132	132	133	136	20	13	0.2
Other renewables	18	27	28	49	62	75	88	4	8	4.8
Power generation	**95**	**204**	**215**	**303**	**355**	**409**	**466**	**100**	**100**	**3.3**
Coal	19	80	83	132	155	177	205	39	44	3.8
Oil	18	7	9	6	6	5	4	4	1	-3.0
Gas	34	75	77	85	91	101	107	36	23	1.4
Nuclear	-	-	-	-	-	1	4	-	1	n.a.
Hydro	4	9	11	17	23	27	30	5	6	4.4
Bioenergy	1	5	7	15	20	25	31	3	7	6.4
Other renewables	18	27	28	49	61	73	86	13	18	4.7
Other energy sector	**47**	**55**	**56**	**60**	**64**	**70**	**76**	**100**	**100**	**1.2**
Electricity	*4*	*8*	*9*	*13*	*16*	*19*	*22*	*16*	*29*	*3.8*
TFC	**276**	**440**	**453**	**560**	**614**	**665**	**714**	**100**	**100**	**1.9**
Coal	13	29	29	44	51	57	63	6	9	3.3
Oil	126	196	202	252	269	281	288	45	40	1.5
Gas	17	37	37	54	66	80	94	8	13	4.0
Electricity	28	68	73	105	126	148	172	16	24	3.7
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	92	110	112	106	102	98	94	25	13	-0.7
Other renewables	-	-	-	0	1	1	2	-	0	n.a.
Industry	**76**	**127**	**129**	**176**	**202**	**228**	**255**	**100**	**100**	**2.9**
Coal	13	28	27	42	49	56	62	21	24	3.4
Oil	24	22	22	27	28	29	30	17	12	1.2
Gas	9	30	29	42	52	63	75	23	29	4.0
Electricity	12	28	30	41	48	55	62	23	24	3.2
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	18	20	21	23	24	25	26	16	10	1.0
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Transport	**61**	**118**	**123**	**157**	**170**	**180**	**186**	**100**	**100**	**1.7**
Oil	61	111	115	145	157	164	168	94	90	1.6
Electricity	0	0	0	1	1	2	2	0	1	9.5
Biofuels	-	3	4	7	8	9	10	3	5	4.0
Other fuels	0	3	3	4	5	5	5	2	3	2.5
Buildings	**108**	**144**	**149**	**161**	**170**	**180**	**193**	**100**	**100**	**1.1**
Coal	1	1	1	2	2	2	2	1	1	0.3
Oil	19	17	18	19	20	21	21	12	11	0.8
Gas	0	0	0	2	3	4	5	0	3	11.4
Electricity	15	39	42	62	76	90	105	28	55	3.9
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	73	86	87	76	70	63	58	59	30	-1.7
Traditional biomass	*73*	*86*	*87*	*75*	*69*	*63*	*57*	*58*	*30*	*-1.7*
Other renewables	-	-	-	0	1	1	1	-	1	n.a.
Other	**30**	**51**	**52**	**68**	**72**	**76**	**79**	**100**	**100**	**1.8**
Petrochem. feedstock	*20*	*33*	*34*	*46*	*49*	*52*	*54*	*23*	*28*	*2.0*

Southeast Asia: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						**Shares** (%)		**CAAGR** (%)	
	2025	**2030**	**2040**	**2025**	**2030**	**2040**	**2040**		**2016e-40**	
	Current Policies			**Sustainable Development**			**CPS**	**SDS**	**CPS**	**SDS**
TPED	**823**	**925**	**1 133**	**732**	**781**	**891**	**100**	**100**	**2.4**	**1.4**
Coal	189	236	338	135	108	78	30	9	4.7	-1.5
Oil	277	300	333	256	260	248	29	28	1.7	0.5
Gas	164	184	229	165	182	200	20	22	2.0	1.4
Nuclear	-	-	4	-	-	9	0	1	n.a.	n.a.
Hydro	15	19	24	19	27	42	2	5	3.4	5.9
Bioenergy	131	131	133	90	81	99	12	11	0.1	-1.1
Other renewables	46	55	73	68	122	215	6	24	4.0	8.8
Power generation	**312**	**372**	**503**	**290**	**332**	**419**	**100**	**100**	**3.6**	**2.8**
Coal	145	181	266	94	63	28	53	7	5.0	-4.4
Oil	6	6	5	6	5	3	1	1	-2.7	-4.5
Gas	86	93	105	88	95	90	21	22	1.3	0.7
Nuclear	-	-	4	-	-	9	1	2	n.a.	n.a.
Hydro	15	19	24	19	27	42	5	10	3.4	5.9
Bioenergy	15	19	27	17	23	38	5	9	5.8	7.3
Other renewables	45	54	71	66	119	209	14	50	3.9	8.7
Other energy sector	**62**	**68**	**83**	**57**	**59**	**62**	**100**	**100**	**1.6**	**0.4**
Electricity	*14*	*17*	*24*	*13*	*14*	*17*	*29*	*28*	*4.2*	*2.7*
TFC	**570**	**633**	**752**	**500**	**524**	**584**	**100**	**100**	**2.1**	**1.1**
Coal	44	53	66	40	44	48	9	8	3.5	2.1
Oil	257	280	312	240	245	234	41	40	1.8	0.6
Gas	55	67	97	54	65	88	13	15	4.1	3.7
Electricity	107	130	181	102	119	157	24	27	3.9	3.3
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	106	102	95	62	48	50	13	9	-0.7	-3.3
Other renewables	0	1	1	1	3	7	0	1	n.a.	n.a.
Industry	**179**	**207**	**265**	**166**	**180**	**211**	**100**	**100**	**3.0**	**2.1**
Coal	43	51	64	39	43	47	24	22	3.6	2.3
Oil	27	29	31	25	25	25	12	12	1.3	0.5
Gas	43	54	78	40	46	60	30	29	4.2	3.1
Electricity	42	49	64	39	42	52	24	24	3.3	2.3
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	24	25	28	22	23	24	10	11	1.2	0.6
Other renewables	0	0	0	0	1	3	0	1	n.a.	n.a.
Transport	**160**	**178**	**203**	**151**	**158**	**156**	**100**	**100**	**2.1**	**1.0**
Oil	150	166	188	134	134	119	93	76	2.1	0.1
Electricity	0	1	1	1	3	8	1	5	6.3	15.2
Biofuels	6	7	8	10	14	18	4	12	3.2	6.5
Other fuels	4	4	5	5	7	11	3	7	2.4	5.8
Buildings	**163**	**175**	**205**	**116**	**114**	**138**	**100**	**100**	**1.3**	**-0.3**
Coal	2	2	2	2	1	1	1	0	1.6	-3.9
Oil	20	21	23	20	22	23	11	17	1.2	1.1
Gas	2	3	5	3	5	8	3	6	11.4	13.1
Electricity	64	80	114	61	73	96	56	70	4.3	3.5
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	76	70	58	30	11	7	28	5	-1.7	-10.1
Traditional biomass	*75*	*69*	*57*	*29*	*9*	*6*	*28*	*4*	*-1.7*	*-10.8*
Other renewables	0	0	1	1	2	3	0	3	n.a.	n.a.
Other	**68**	**72**	**80**	**68**	**72**	**79**	**100**	**100**	**1.8**	**1.8**
Petrochem. feedstock	*45*	*49*	*54*	*46*	*49*	*55*	*26*	*40*	*2.0*	*2.1*

Southeast Asia: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**370**	**867**	**918**	**1 341**	**1 617**	**1 905**	**2 219**	**100**	**100**	**3.7**
Coal	79	308	321	548	655	764	898	35	40	4.4
Oil	72	30	35	21	21	18	15	4	1	-3.5
Gas	154	384	395	455	501	569	630	43	28	2.0
Nuclear	-	-	-	-	-	2	16	-	1	n.a.
Renewables	65	145	167	317	440	553	659	18	30	5.9
Hydro	47	109	124	193	263	312	347	14	16	4.4
Bioenergy	1	12	15	43	58	76	97	2	4	8.1
Wind	-	1	1	13	22	36	55	0	2	16.7
Geothermal	16	21	22	42	54	65	75	2	3	5.2
Solar PV	0	3	4	25	43	63	85	0	4	13.5
CSP	-	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**228**	**241**	**349**	**418**	**490**	**566**	**100**	**100**	**3.6**
Coal	62	66	107	123	139	160	27	28	3.8
Oil	25	26	24	22	19	13	11	2	-2.8
Gas	88	93	116	132	156	181	39	32	2.8
Nuclear	-	-	-	-	1	2	-	0	n.a.
Renewables	53	57	102	141	176	210	23	37	5.6
Hydro	39	41	61	82	96	105	17	19	4.1
Bioenergy	7	7	12	14	16	19	3	3	3.9
Wind	1	1	5	9	14	22	0	4	13.8
Geothermal	3	3	6	8	10	11	1	2	5.1
Solar PV	3	4	17	28	40	53	2	9	11.1
CSP	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**692**	**1 242**	**1 278**	**1 682**	**1 885**	**2 080**	**2 273**	**100**	**100**	**2.4**
Coal	134	439	453	710	833	950	1 083	35	48	3.7
Oil	413	508	529	636	681	712	729	41	32	1.3
Gas	146	295	297	336	371	418	461	23	20	1.9
Power generation	**217**	**520**	**543**	**749**	**856**	**966**	**1 087**	**100**	**100**	**2.9**
Coal	78	322	335	532	624	714	823	62	76	3.8
Oil	58	23	27	18	18	16	13	5	1	-3.0
Gas	81	175	181	199	214	237	251	33	23	1.4
TFC	**410**	**649**	**663**	**867**	**964**	**1 046**	**1 116**	**100**	**100**	**2.2**
Coal	55	118	118	178	209	236	261	18	23	3.4
Oil	333	468	485	598	642	672	690	73	62	1.5
Transport	*185*	*333*	*345*	*434*	*468*	*491*	*502*	*52*	*45*	*1.6*
Gas	21	63	60	92	113	138	165	9	15	4.3

Southeast Asia: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**1 380**	**1 683**	**2 352**	**1 299**	**1 520**	**1 997**	**100**	**100**	**4.0**	**3.3**
Coal	601	766	1 178	392	268	128	50	6	5.6	-3.8
Oil	24	23	16	22	16	10	1	0	-3.2	-5.2
Gas	461	514	627	484	533	534	27	27	1.9	1.3
Nuclear	-	-	14	-	-	36	1	2	n.a.	n.a.
Renewables	295	380	517	402	703	1 289	22	65	4.8	8.9
Hydro	180	227	281	216	315	492	12	25	3.5	5.9
Bioenergy	43	55	85	48	70	123	4	6	7.5	9.2
Wind	13	20	35	43	125	246	1	12	14.5	24.2
Geothermal	39	48	64	59	107	183	3	9	4.5	9.2
Solar PV	21	31	52	36	85	243	2	12	11.2	18.6
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	-	-	-	0	2	-	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**349**	**416**	**557**	**367**	**472**	**677**	**100**	**100**	**3.6**	**4.4**
Coal	115	142	215	92	84	63	39	9	5.0	-0.2
Oil	24	22	13	23	22	12	2	2	-2.7	-2.9
Gas	118	135	173	114	119	133	31	20	2.6	1.5
Nuclear	-	-	2	-	-	5	0	1	n.a.	n.a.
Renewables	93	118	154	137	247	464	28	69	4.3	9.2
Hydro	56	70	85	70	99	151	15	22	3.1	5.6
Bioenergy	12	13	17	13	16	24	3	4	3.4	5.0
Wind	5	8	13	20	55	100	2	15	11.3	21.2
Geothermal	6	7	9	9	16	27	2	4	4.3	9.0
Solar PV	14	20	30	26	60	161	5	24	8.6	16.4
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	-	-	-	0	1	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**1 759**	**2 039**	**2 615**	**1 481**	**1 399**	**1 203**	**100**	**100**	**3.0**	**-0.2**
Coal	763	942	1 345	544	427	261	51	22	4.6	-2.3
Oil	656	717	802	596	598	544	31	45	1.8	0.1
Gas	340	380	468	342	375	398	18	33	1.9	1.2
Power generation	**802**	**964**	**1 333**	**605**	**489**	**302**	**100**	**100**	**3.8**	**-2.4**
Coal	582	726	1 072	380	251	81	80	27	5.0	-5.8
Oil	20	20	14	18	15	9	1	3	-2.7	-4.5
Gas	201	218	248	207	223	212	19	70	1.3	0.7
TFC	**889**	**1 006**	**1 204**	**817**	**854**	**851**	**100**	**100**	**2.5**	**1.0**
Coal	181	215	273	164	175	180	23	21	3.6	1.8
Oil	615	675	761	561	567	520	63	61	1.9	0.3
Transport	*448*	*496*	*562*	*401*	*401*	*354*	*47*	*42*	*2.1*	*0.1*
Gas	93	115	170	92	112	151	14	18	4.4	3.9

OECD: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**5 295**	**5 259**	**5 255**	**5 221**	**5 138**	**5 066**	**5 049**	**100**	**100**	**-0.2**
Coal	1 095	950	886	765	702	634	597	17	12	-1.6
Oil	2 115	1 893	1 902	1 742	1 617	1 485	1 392	36	28	-1.3
Gas	1 163	1 373	1 402	1 468	1 508	1 563	1 593	27	32	0.5
Nuclear	586	514	511	517	489	468	461	10	9	-0.4
Hydro	115	119	121	134	139	143	147	2	3	0.8
Bioenergy	184	303	312	378	408	435	460	6	9	1.6
Other renewables	37	108	120	216	274	338	399	2	8	5.1
Power generation	**2 136**	**2 155**	**2 144**	**2 107**	**2 107**	**2 119**	**2 155**	**100**	**100**	**0.0**
Coal	894	748	691	579	526	467	437	32	20	-1.9
Oil	145	61	56	24	19	15	11	3	1	-6.6
Gas	320	512	549	523	543	571	582	26	27	0.2
Nuclear	586	514	511	517	489	468	461	24	21	-0.4
Hydro	115	119	121	134	139	143	147	6	7	0.8
Bioenergy	46	104	107	137	148	159	170	5	8	1.9
Other renewables	31	98	109	192	242	296	348	5	16	5.0
Other energy sector	**424**	**475**	**464**	**494**	**492**	**496**	**503**	**100**	**100**	**0.3**
Electricity	*122*	*126*	*127*	*124*	*125*	*126*	*129*	*27*	*26*	*0.1*
TFC	**3 633**	**3 634**	**3 660**	**3 682**	**3 630**	**3 575**	**3 552**	**100**	**100**	**-0.1**
Coal	139	111	109	102	95	88	82	3	2	-1.2
Oil	1 838	1 732	1 747	1 618	1 502	1 384	1 301	48	37	-1.2
Gas	744	718	718	774	789	802	809	20	23	0.5
Electricity	718	808	815	867	897	931	967	22	27	0.7
Heat	50	57	57	58	57	56	54	2	2	-0.2
Bioenergy	138	198	203	239	258	273	287	6	8	1.5
Other renewables	6	10	11	24	33	42	52	0	1	6.6
Industry	**921**	**836**	**846**	**882**	**876**	**869**	**869**	**100**	**100**	**0.1**
Coal	118	89	89	85	81	76	71	10	8	-0.9
Oil	149	122	126	121	115	109	104	15	12	-0.8
Gas	286	272	275	299	299	298	299	33	34	0.3
Electricity	280	255	258	271	273	276	281	30	32	0.4
Heat	18	24	24	24	22	21	20	3	2	-0.9
Bioenergy	70	72	74	81	84	87	90	9	10	0.8
Other renewables	0	0	0	1	2	3	5	0	1	9.8
Transport	**1 143**	**1 231**	**1 241**	**1 172**	**1 117**	**1 063**	**1 035**	**100**	**100**	**-0.8**
Oil	1 109	1 147	1 156	1 048	964	881	827	93	80	-1.4
Electricity	9	9	9	17	23	31	42	1	4	6.4
Biofuels	4	49	51	71	82	89	95	4	9	2.6
Other fuels	21	25	25	37	49	61	70	2	7	4.5
Buildings	**1 142**	**1 197**	**1 201**	**1 230**	**1 244**	**1 259**	**1 275**	**100**	**100**	**0.3**
Coal	17	18	16	13	11	8	7	1	1	-3.4
Oil	211	136	138	107	87	68	54	11	4	-3.8
Gas	391	397	394	405	407	409	407	33	32	0.1
Electricity	423	531	536	568	590	612	634	45	50	0.7
Heat	32	33	32	34	34	34	34	3	3	0.3
Bioenergy	62	73	75	83	87	92	95	6	7	1.0
Traditional biomass	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*n.a.*
Other renewables	5	9	9	21	28	36	44	1	3	6.6
Other	**426**	**370**	**373**	**398**	**393**	**384**	**374**	**100**	**100**	**0.0**
Petrochem. feedstock	*266*	*221*	*221*	*239*	*234*	*226*	*218*	*18*	*17*	*-0.1*

OECD: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**5 379**	**5 409**	**5 524**	**4 906**	**4 624**	**4 258**	**100**	**100**	**0.2**	**-0.9**
Coal	840	806	766	473	277	194	14	5	-0.6	-6.1
Oil	1 801	1 730	1 601	1 600	1 353	928	29	22	-0.7	-2.9
Gas	1 510	1 580	1 735	1 464	1 398	1 136	31	27	0.9	-0.9
Nuclear	529	526	514	553	586	618	9	15	0.0	0.8
Hydro	134	138	146	137	145	157	3	4	0.8	1.1
Bioenergy	367	391	441	419	478	551	8	13	1.5	2.4
Other renewables	198	238	321	260	387	674	6	16	4.2	7.5
Power generation	**2 199**	**2 254**	**2 374**	**1 946**	**1 884**	**1 950**	**100**	**100**	**0.4**	**-0.4**
Coal	652	627	590	301	124	71	25	4	-0.7	-9.0
Oil	25	20	12	20	13	6	1	0	-6.1	-9.0
Gas	547	585	663	569	520	310	28	16	0.8	-2.3
Nuclear	529	526	514	553	586	618	22	32	0.0	0.8
Hydro	134	138	146	137	145	157	6	8	0.8	1.1
Bioenergy	133	141	158	140	160	201	7	10	1.6	2.7
Other renewables	181	217	290	225	335	587	12	30	4.2	7.3
Other energy sector	**510**	**520**	**560**	**464**	**436**	**380**	**100**	**100**	**0.8**	**-0.8**
Electricity	*129*	*133*	*142*	*116*	*112*	*110*	*25*	*29*	*0.5*	*-0.6*
TFC	**3 764**	**3 777**	**3 831**	**3 516**	**3 337**	**3 026**	**100**	**100**	**0.2**	**-0.8**
Coal	104	98	87	94	83	64	2	2	-0.9	-2.2
Oil	1 672	1 605	1 499	1 486	1 258	866	39	29	-0.6	-2.9
Gas	787	809	845	733	718	681	22	23	0.7	-0.2
Electricity	893	937	1 028	835	856	930	27	31	1.0	0.6
Heat	59	59	59	56	54	49	2	2	0.1	-0.6
Bioenergy	232	248	281	277	316	348	7	11	1.4	2.3
Other renewables	17	22	32	35	52	88	1	3	4.5	9.0
Industry	**893**	**898**	**907**	**845**	**812**	**760**	**100**	**100**	**0.3**	**-0.4**
Coal	86	82	73	79	71	57	8	8	-0.8	-1.8
Oil	123	118	109	113	103	85	12	11	-0.6	-1.6
Gas	303	307	312	286	274	247	34	33	0.5	-0.4
Electricity	274	279	291	260	251	247	32	32	0.5	-0.2
Heat	24	23	21	23	21	17	2	2	-0.6	-1.5
Bioenergy	83	88	98	81	85	94	11	12	1.2	1.0
Other renewables	1	1	3	3	6	14	0	2	7.9	14.9
Transport	**1 201**	**1 175**	**1 157**	**1 112**	**1 004**	**817**	**100**	**100**	**-0.3**	**-1.7**
Oil	1 091	1 048	997	940	758	446	86	55	-0.6	-3.9
Electricity	14	17	23	25	52	128	2	16	3.8	11.5
Biofuels	65	73	90	110	142	161	8	20	2.4	4.9
Other fuels	31	37	47	37	53	83	4	10	2.8	5.2
Buildings	**1 271**	**1 310**	**1 389**	**1 168**	**1 136**	**1 086**	**100**	**100**	**0.6**	**-0.4**
Coal	14	13	11	12	8	4	1	0	-1.8	-6.2
Oil	116	101	75	97	71	32	5	3	-2.5	-5.9
Gas	420	432	452	377	359	319	32	29	0.6	-0.9
Electricity	592	629	702	540	542	546	51	50	1.1	0.1
Heat	35	35	37	33	33	32	3	3	0.6	-0.0
Bioenergy	80	82	87	80	81	83	6	8	0.6	0.4
Traditional biomass	-	-	-	-	-	-	-	-	*n.a.*	*n.a.*
Other renewables	15	18	26	29	42	69	2	6	4.4	8.7
Other	**398**	**394**	**377**	**392**	**384**	**362**	**100**	**100**	**0.0**	**-0.1**
Petrochem. feedstock	*238*	*232*	*216*	*237*	*231*	*216*	*16*	*20*	*-0.1*	*-0.1*

OECD: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**9 767**	**10 839**	**10 935**	**11 558**	**11 909**	**12 305**	**12 746**	**100**	**100**	**0.6**
Coal	3 793	3 228	2 964	2 545	2 332	2 095	1 986	27	16	-1.7
Oil	637	261	237	100	79	59	39	2	0	-7.2
Gas	1 543	2 846	3 089	3 104	3 292	3 504	3 606	28	28	0.6
Nuclear	2 249	1 971	1 962	1 985	1 876	1 796	1 768	18	14	-0.4
Renewables	1 545	2 534	2 684	3 824	4 329	4 851	5 347	25	42	2.9
Hydro	1 339	1 379	1 410	1 558	1 620	1 665	1 710	13	13	0.8
Bioenergy	143	355	371	484	529	572	609	3	5	2.1
Wind	29	556	622	1 163	1 403	1 666	1 901	6	15	4.8
Geothermal	33	50	54	74	96	122	145	0	1	4.2
Solar PV	1	183	216	525	643	762	878	2	7	6.0
CSP	1	9	10	17	26	38	54	0	0	7.4
Marine	1	1	1	4	12	26	50	0	0	16.8

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**2 995**	**3 056**	**3 413**	**3 579**	**3 764**	**3 942**	**100**	**100**	**1.1**
Coal	617	605	516	478	432	405	20	10	-1.7
Oil	190	188	97	75	63	52	6	1	-5.2
Gas	902	913	1 042	1 108	1 186	1 253	30	32	1.3
Nuclear	313	314	276	253	241	237	10	6	-1.2
Renewables	973	1 035	1 481	1 665	1 842	1 995	34	51	2.8
Hydro	482	485	510	525	536	547	16	14	0.5
Bioenergy	74	77	98	106	113	119	3	3	1.8
Wind	238	263	445	518	590	649	9	16	3.8
Geothermal	8	8	11	14	18	21	0	1	3.9
Solar PV	166	198	409	489	562	624	6	16	4.9
CSP	4	4	6	9	12	16	0	0	5.8
Marine	1	1	2	5	11	20	0	1	16.3

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**12 371**	**11 602**	**11 456**	**10 491**	**9 956**	**9 420**	**9 072**	**100**	**100**	**-1.0**
Coal	4 421	3 714	3 472	2 960	2 702	2 410	2 251	30	25	-1.8
Oil	5 335	4 756	4 776	4 216	3 853	3 497	3 257	42	36	-1.6
Gas	2 615	3 132	3 208	3 315	3 401	3 513	3 565	28	39	0.4
Power generation	**4 914**	**4 521**	**4 352**	**3 711**	**3 516**	**3 313**	**3 197**	**100**	**100**	**-1.3**
Coal	3 697	3 116	2 878	2 400	2 176	1 922	1 794	66	56	-2.0
Oil	467	194	178	77	61	48	35	4	1	-6.6
Gas	751	1 210	1 296	1 234	1 279	1 343	1 369	30	43	0.2
TFC	**6 821**	**6 345**	**6 375**	**6 000**	**5 671**	**5 343**	**5 112**	**100**	**100**	**-0.9**
Coal	653	481	480	448	418	386	359	8	7	-1.2
Oil	4 516	4 256	4 288	3 841	3 510	3 185	2 964	67	58	-1.5
Transport	*3 295*	*3 423*	*3 450*	*3 124*	*2 875*	*2 628*	*2 467*	*54*	*48*	*-1.4*
Gas	1 653	1 608	1 607	1 710	1 742	1 772	1 789	25	35	0.4

OECD: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**11 914**	**12 473**	**13 616**	**11 088**	**11 266**	**12 087**	**100**	**100**	**0.9**	**0.4**
Coal	2 875	2 801	2 723	1 315	523	267	20	2	-0.4	-9.5
Oil	104	83	47	80	47	15	0	0	-6.5	-11.0
Gas	3 233	3 540	4 130	3 370	3 130	1 765	30	15	1.2	-2.3
Nuclear	2 030	2 018	1 972	2 124	2 249	2 373	14	20	0.0	0.8
Renewables	3 672	4 030	4 744	4 200	5 317	7 667	35	63	2.4	4.5
Hydro	1 552	1 608	1 698	1 590	1 683	1 823	12	15	0.8	1.1
Bioenergy	468	498	559	507	594	769	4	6	1.7	3.1
Wind	1 091	1 259	1 589	1 365	1 943	3 073	12	25	4.0	6.9
Geothermal	73	92	129	81	121	206	1	2	3.7	5.7
Solar PV	470	544	706	626	889	1 446	5	12	5.1	8.3
CSP	16	21	41	25	72	273	0	2	6.3	14.9
Marine	3	7	22	4	15	77	0	1	12.9	18.9

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**3 404**	**3 554**	**3 895**	**3 473**	**3 763**	**4 451**	**100**	**100**	**1.0**	**1.6**
Coal	539	515	488	478	336	143	13	3	-0.9	-5.8
Oil	98	78	56	87	64	38	1	1	-5.0	-6.5
Gas	1 075	1 161	1 350	958	979	1 040	35	23	1.6	0.5
Nuclear	284	274	262	293	305	318	7	7	-0.8	0.0
Renewables	1 407	1 526	1 739	1 657	2 079	2 913	45	65	2.2	4.4
Hydro	508	520	541	522	548	586	14	13	0.5	0.8
Bioenergy	95	100	109	103	119	151	3	3	1.5	2.9
Wind	420	470	555	517	698	1 025	14	23	3.2	5.8
Geothermal	11	13	19	12	18	30	0	1	3.4	5.4
Solar PV	367	412	494	492	667	1 010	13	23	3.9	7.0
CSP	6	7	12	9	24	80	0	2	4.7	13.2
Marine	1	3	9	2	6	31	0	1	12.2	18.3

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**11 089**	**10 907**	**10 707**	**8 866**	**7 065**	**4 518**	**100**	**100**	**-0.3**	**-3.8**
Coal	3 275	3 144	2 928	1 766	921	432	27	10	-0.7	-8.3
Oil	4 393	4 186	3 892	3 806	3 082	1 866	36	41	-0.8	-3.8
Gas	3 422	3 577	3 887	3 294	3 061	2 221	36	49	0.8	-1.5
Power generation	**4 073**	**4 045**	**4 044**	**2 656**	**1 692**	**662**	**100**	**100**	**-0.3**	**-7.5**
Coal	2 704	2 601	2 442	1 253	477	129	60	19	-0.7	-12.1
Oil	80	65	40	64	42	19	1	3	-6.0	-8.9
Gas	1 288	1 379	1 562	1 340	1 173	515	39	78	0.8	-3.8
TFC	**6 207**	**6 045**	**5 815**	**5 492**	**4 735**	**3 389**	**100**	**100**	**-0.4**	**-2.6**
Coal	457	433	385	412	354	237	7	7	-0.9	-2.9
Oil	4 004	3 819	3 553	3 467	2 810	1 691	61	50	-0.8	-3.8
Transport	*3 253*	*3 127*	*2 974*	*2 803*	*2 260*	*1 329*	*51*	*39*	*-0.6*	*-3.9*
Gas	1 745	1 793	1 876	1 613	1 571	1 460	32	43	0.6	-0.4

Non-OECD: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
TPED	**4 467**	**7 995**	**8 117**	**9 503**	**10 367**	**11 180**	**11 918**	**100**	**100**	**1.6**
Coal	1 215	2 887	2 869	3 076	3 194	3 275	3 332	35	28	0.6
Oil	1 281	2 055	2 099	2 448	2 619	2 762	2 879	26	24	1.3
Gas	909	1 565	1 605	1 954	2 208	2 474	2 721	20	23	2.2
Nuclear	89	157	170	322	408	481	541	2	5	5.0
Hydro	110	216	229	279	320	356	385	3	3	2.2
Bioenergy	839	1 023	1 042	1 151	1 216	1 275	1 325	13	11	1.0
Other renewables	23	92	105	274	402	558	734	1	6	8.4
Power generation	**1 507**	**3 031**	**3 109**	**3 702**	**4 118**	**4 537**	**4 939**	**100**	**100**	**1.9**
Coal	671	1 620	1 633	1 758	1 834	1 885	1 915	53	39	0.7
Oil	177	216	219	176	152	137	126	7	3	-2.3
Gas	428	691	709	817	907	1 007	1 100	23	22	1.9
Nuclear	89	157	170	322	408	481	541	5	11	5.0
Hydro	110	216	229	279	320	356	385	7	8	2.2
Bioenergy	11	67	75	128	162	203	248	2	5	5.1
Other renewables	20	64	74	224	334	469	623	2	13	9.3
Other energy sector	**552**	**1 016**	**1 022**	**1 106**	**1 168**	**1 221**	**1 267**	**100**	**100**	**0.9**
Electricity	*117*	*223*	*230*	*268*	*300*	*334*	*366*	*22*	*29*	*2.0*
TFC	**3 133**	**5 357**	**5 438**	**6 532**	**7 170**	**7 762**	**8 291**	**100**	**100**	**1.8**
Coal	409	928	911	964	985	1 000	1 011	17	12	0.4
Oil	1 006	1 707	1 743	2 130	2 326	2 487	2 620	32	32	1.7
Gas	373	689	708	958	1 117	1 273	1 417	13	17	2.9
Electricity	375	932	963	1 292	1 507	1 721	1 927	18	23	2.9
Heat	198	214	217	237	243	247	249	4	3	0.6
Bioenergy	770	858	866	901	924	944	956	16	12	0.4
Other renewables	3	28	31	50	68	90	111	1	1	5.5
Industry	**946**	**1 961**	**1 980**	**2 388**	**2 613**	**2 829**	**3 026**	**100**	**100**	**1.8**
Coal	282	732	723	780	812	840	865	37	29	0.7
Oil	178	209	213	234	241	246	249	11	8	0.7
Gas	128	323	332	461	538	618	696	17	23	3.1
Electricity	182	475	487	632	710	782	846	25	28	2.3
Heat	83	100	102	119	122	123	122	5	4	0.8
Bioenergy	92	121	122	161	187	213	238	6	8	2.8
Other renewables	0	0	0	1	3	6	9	0	0	15.5
Transport	**542**	**1 082**	**1 093**	**1 398**	**1 568**	**1 713**	**1 842**	**100**	**100**	**2.2**
Oil	485	954	961	1 201	1 330	1 431	1 513	88	82	1.9
Electricity	10	27	27	41	53	66	80	2	4	4.6
Biofuels	6	26	27	48	61	74	88	2	5	5.1
Other fuels	41	75	78	108	124	142	161	7	9	3.1
Buildings	**1 308**	**1 761**	**1 792**	**1 997**	**2 163**	**2 328**	**2 477**	**100**	**100**	**1.4**
Coal	91	116	111	93	80	67	54	6	2	-2.9
Oil	135	185	190	198	203	209	217	11	9	0.6
Gas	141	232	238	308	364	415	455	13	18	2.7
Electricity	159	386	402	556	674	795	918	22	37	3.5
Heat	110	111	112	115	118	121	123	6	5	0.4
Bioenergy	669	704	710	680	662	639	610	40	25	-0.6
Traditional biomass	*646*	*673*	*678*	*642*	*619*	*591*	*557*	*38*	*22*	*-0.8*
Other renewables	3	27	30	47	63	82	99	2	4	5.2
Other	**338**	**553**	**572**	**750**	**825**	**892**	**946**	**100**	**100**	**2.1**
Petrochem. feedstock	*176*	*289*	*308*	*439*	*496*	*551*	*599*	*17*	*24*	*2.8*

Non-OECD: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**9 831**	**10 942**	**13 099**	**8 612**	**8 801**	**9 397**	**100**	**100**	**2.0**	**0.6**
Coal	3 326	3 656	4 280	2 550	2 180	1 583	33	17	1.7	-2.4
Oil	2 542	2 792	3 233	2 295	2 277	2 083	25	22	1.8	-0.0
Gas	1 996	2 285	2 916	1 906	2 078	2 274	22	24	2.5	1.5
Nuclear	310	374	483	367	534	775	4	8	4.5	6.5
Hydro	275	309	367	292	344	439	3	5	2.0	2.8
Bioenergy	1 139	1 194	1 285	830	738	920	10	10	0.9	-0.5
Other renewables	243	332	535	373	649	1 322	4	14	7.0	11.1
Power generation	**3 890**	**4 431**	**5 551**	**3 367**	**3 542**	**4 038**	**100**	**100**	**2.4**	**1.1**
Coal	1 960	2 209	2 695	1 317	986	507	49	13	2.1	-4.8
Oil	179	156	132	147	107	56	2	1	-2.1	-5.5
Gas	848	966	1 234	790	826	803	22	20	2.3	0.5
Nuclear	310	374	483	367	534	775	9	19	4.5	6.5
Hydro	275	309	367	292	344	439	7	11	2.0	2.8
Bioenergy	122	147	202	145	192	310	4	8	4.2	6.1
Other renewables	196	270	438	309	553	1 149	8	28	7.7	12.1
Other energy sector	**1 146**	**1 243**	**1 429**	**975**	**960**	**946**	**100**	**100**	**1.4**	**-0.3**
Electricity	*286*	*329*	*419*	*248*	*263*	*300*	*29*	*32*	*2.5*	*1.1*
TFC	**6 701**	**7 472**	**8 914**	**6 015**	**6 224**	**6 719**	**100**	**100**	**2.1**	**0.9**
Coal	1 004	1 053	1 132	904	863	754	13	11	0.9	-0.8
Oil	2 215	2 485	2 958	2 022	2 057	1 943	33	29	2.2	0.5
Gas	964	1 126	1 448	945	1 083	1 312	16	20	3.0	2.6
Electricity	1 333	1 577	2 061	1 230	1 402	1 768	23	26	3.2	2.6
Heat	245	255	272	229	225	210	3	3	0.9	-0.2
Bioenergy	893	914	946	620	497	559	11	8	0.4	-1.8
Other renewables	47	62	97	64	96	174	1	3	4.9	7.5
Industry	**2 446**	**2 723**	**3 253**	**2 275**	**2 373**	**2 520**	**100**	**100**	**2.1**	**1.0**
Coal	806	859	952	729	710	651	29	26	1.2	-0.4
Oil	239	249	263	222	219	213	8	8	0.9	-0.0
Gas	464	549	728	446	501	592	22	24	3.3	2.4
Electricity	649	742	917	597	636	708	28	28	2.7	1.6
Heat	124	130	139	115	111	99	4	4	1.3	-0.1
Bioenergy	164	192	250	159	182	228	8	9	3.0	2.6
Other renewables	1	2	4	5	13	29	0	1	12.2	21.4
Transport	**1 435**	**1 646**	**2 038**	**1 334**	**1 414**	**1 462**	**100**	**100**	**2.6**	**1.2**
Oil	1 263	1 452	1 784	1 112	1 100	927	88	63	2.6	-0.1
Electricity	33	39	51	41	66	165	2	11	2.6	7.8
Biofuels	38	46	65	68	101	145	3	10	3.8	7.3
Other fuels	100	110	139	113	146	224	7	15	2.4	4.5
Buildings	**2 061**	**2 259**	**2 635**	**1 669**	**1 635**	**1 832**	**100**	**100**	**1.6**	**0.1**
Coal	103	96	80	87	67	22	3	1	-1.4	-6.5
Oil	210	223	247	198	201	192	9	10	1.1	0.1
Gas	318	377	476	305	348	395	18	22	2.9	2.1
Electricity	586	722	1 001	531	633	820	38	45	3.9	3.0
Heat	118	122	129	111	111	108	5	6	0.6	-0.2
Bioenergy	680	662	611	380	195	155	23	8	-0.6	-6.1
Traditional biomass	*642*	*619*	*557*	*340*	*148*	*102*	*21*	*6*	*-0.8*	*-7.6*
Other renewables	45	59	90	56	80	139	3	8	4.7	6.6
Other	**759**	**843**	**987**	**737**	**802**	**906**	**100**	**100**	**2.3**	**1.9**
Petrochem. feedstock	*440*	*499*	*612*	*434*	*487*	*585*	*23*	*32*	*2.9*	*2.7*

Non-OECD: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total generation	**5 710**	**13 401**	**13 835**	**18 100**	**20 955**	**23 792**	**26 543**	**100**	**100**	**2.8**
Coal	2 212	6 305	6 319	7 130	7 548	7 873	8 100	46	31	1.0
Oil	623	761	770	619	542	490	452	6	2	-2.2
Gas	1 210	2 674	2 761	3 626	4 288	4 940	5 574	20	21	3.0
Nuclear	341	600	649	1 233	1 564	1 846	2 076	5	8	5.0
Renewables	1 323	3 061	3 337	5 492	7 014	8 644	10 341	24	39	4.8
Hydro	1 280	2 509	2 660	3 246	3 724	4 135	4 484	19	17	2.2
Bioenergy	21	175	199	382	507	653	814	1	3	6.1
Wind	3	282	359	1 029	1 434	1 882	2 369	3	9	8.2
Geothermal	19	30	32	66	101	147	203	0	1	8.1
Solar PV	0	63	87	740	1 184	1 709	2 284	1	9	14.6
CSP	-	1	1	28	63	116	183	0	1	24.3
Marine	0	0	0	0	1	2	3	0	0	26.4

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total capacity	**3 419**	**3 621**	**5 234**	**6 146**	**7 093**	**8 018**	**100**	**100**	**3.4**
Coal	1 346	1 415	1 711	1 818	1 928	2 028	39	25	1.5
Oil	249	255	237	213	196	181	7	2	-1.4
Gas	718	737	1 044	1 217	1 384	1 547	20	19	3.1
Nuclear	92	99	172	214	251	280	3	3	4.4
Renewables	1 013	1 116	2 069	2 684	3 334	3 983	31	50	5.4
Hydro	728	757	950	1 082	1 193	1 284	21	16	2.2
Bioenergy	46	50	82	103	128	154	1	2	4.8
Wind	176	203	487	656	834	1 015	6	13	6.9
Geothermal	5	5	10	15	22	30	0	0	7.9
Solar PV	58	100	530	806	1 119	1 444	3	18	11.7
CSP	1	1	10	21	37	56	0	1	19.3
Marine	0	0	0	0	1	1	0	0	25.0

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2015	2016e	2025	2030	2035	2040	2016e	2040	2016e-40
Total CO_2	**9 800**	**19 311**	**19 424**	**21 504**	**22 785**	**23 893**	**24 812**	**100**	**100**	**1.0**
Coal	4 531	10 773	10 744	11 340	11 690	11 920	12 049	55	49	0.5
Oil	3 335	5 216	5 248	5 950	6 308	6 604	6 852	27	28	1.1
Gas	1 935	3 322	3 432	4 214	4 787	5 369	5 911	18	24	2.3
Power generation	**4 329**	**8 901**	**9 001**	**9 618**	**10 045**	**10 417**	**10 702**	**100**	**100**	**0.7**
Coal	2 757	6 598	6 649	7 147	7 435	7 621	7 718	74	72	0.6
Oil	566	679	684	550	476	427	395	8	4	-2.3
Gas	1 005	1 624	1 668	1 921	2 134	2 369	2 588	19	24	1.8
TFC	**4 930**	**9 503**	**9 508**	**10 962**	**11 792**	**12 506**	**13 115**	**100**	**100**	**1.3**
Coal	1 665	3 918	3 846	3 962	4 032	4 082	4 117	40	31	0.3
Oil	2 546	4 250	4 261	5 085	5 513	5 851	6 128	45	47	1.5
Transport	*1 452*	*2 855*	*2 878*	*3 599*	*3 985*	*4 288*	*4 534*	*30*	*35*	*1.9*
Gas	719	1 335	1 400	1 914	2 247	2 572	2 869	15	22	3.0

Non-OECD: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**18 810**	**22 111**	**28 705**	**17 138**	**19 281**	**23 894**	**100**	**100**	**3.1**	**2.3**
Coal	8 022	9 238	11 662	5 260	3 948	1 928	41	8	2.6	-4.8
Oil	632	560	476	513	365	177	2	1	-2.0	-5.9
Gas	3 800	4 619	6 299	3 533	3 820	3 819	22	16	3.5	1.4
Nuclear	1 188	1 434	1 853	1 407	2 047	2 972	6	12	4.5	6.5
Renewables	5 168	6 260	8 416	6 425	9 100	14 997	29	63	3.9	6.5
Hydro	3 202	3 594	4 266	3 395	4 005	5 105	15	21	2.0	2.8
Bioenergy	366	455	652	445	616	1 038	2	4	5.1	7.1
Wind	892	1 172	1 769	1 420	2 249	3 877	6	16	6.9	10.4
Geothermal	62	86	152	89	170	357	1	1	6.8	10.6
Solar PV	626	916	1 486	1 002	1 844	3 819	5	16	12.6	17.1
CSP	20	37	88	74	214	793	0	3	20.6	32.1
Marine	0	0	2	0	2	8	0	0	25.2	31.8

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**5 160**	**6 003**	**7 600**	**5 426**	**6 475**	**8 649**	**100**	**100**	**3.1**	**3.7**
Coal	1 802	2 019	2 467	1 513	1 350	1 007	32	12	2.3	-1.4
Oil	238	215	186	235	210	173	2	2	-1.3	-1.6
Gas	1 063	1 263	1 634	980	1 053	1 257	21	15	3.4	2.3
Nuclear	165	198	251	198	281	402	3	5	3.9	6.0
Renewables	1 891	2 307	3 063	2 501	3 581	5 811	40	67	4.3	7.1
Hydro	933	1 038	1 216	1 004	1 176	1 474	16	17	2.0	2.8
Bioenergy	79	94	125	93	124	196	2	2	3.9	5.9
Wind	422	536	750	667	1 008	1 603	10	19	5.6	9.0
Geothermal	9	13	22	14	26	52	0	1	6.6	10.4
Solar PV	441	614	922	696	1 179	2 236	12	26	9.7	13.8
CSP	7	12	27	26	68	247	0	3	15.7	27.0
Marine	0	0	1	0	1	3	0	0	23.9	30.7

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2016e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**22 863**	**25 277**	**29 969**	**18 789**	**16 974**	**12 779**	**100**	**100**	**1.8**	**-1.7**
Coal	12 333	13 506	15 743	9 189	7 236	3 670	53	29	1.6	-4.4
Oil	6 222	6 811	7 890	5 501	5 293	4 465	26	35	1.7	-0.7
Gas	4 308	4 961	6 336	4 099	4 445	4 643	21	36	2.6	1.3
Power generation	**10 523**	**11 724**	**14 210**	**7 658**	**6 028**	**3 025**	**100**	**100**	**1.9**	**-4.4**
Coal	7 969	8 963	10 895	5 339	3 767	1 079	77	36	2.1	-7.3
Oil	559	489	412	461	333	176	3	6	-2.1	-5.5
Gas	1 995	2 272	2 904	1 858	1 928	1 770	20	58	2.3	0.2
TFC	**11 385**	**12 546**	**14 635**	**10 300**	**10 172**	**9 103**	**100**	**100**	**1.8**	**-0.2**
Coal	4 124	4 305	4 606	3 642	3 294	2 460	31	27	0.8	-1.8
Oil	5 337	5 981	7 105	4 768	4 716	4 095	49	45	2.2	-0.2
Transport	*3 786*	*4 350*	*5 348*	*3 331*	*3 294*	*2 777*	*37*	*31*	*2.6*	*-0.1*
Gas	1 924	2 260	2 924	1 890	2 162	2 548	20	28	3.1	2.5

World: New Policies Scenario

	Emissions of pollutants by energy sector					Shares (%)		CAAGR (%)
	2015	2025	2030	2035	2040	2015	2040	2015-40
SO_2 emissions from all energy activities (Mt)								
Total	**79.2**	**61.5**	**57.6**	**58.3**	**59.2**	**100**	**100**	**-1.2**
Power	26.7	17.6	14.4	14.4	15.0	34	25	-2.3
Industry*	35.4	34.2	33.8	34.7	35.3	45	60	-0.0
Transport	10.0	3.7	3.9	4.1	4.3	13	7	-3.3
Buildings	5.9	4.8	4.3	3.8	3.5	7	6	-2.1
Agriculture	1.3	1.2	1.2	1.2	1.1	2	2	-0.4
NO_X emissions from all energy activities (Mt)								
Total	**108.0**	**94.5**	**91.7**	**91.4**	**93.3**	**100**	**100**	**-0.6**
Power	16.3	12.3	12.1	12.1	13.1	15	14	-0.9
Industry*	27.7	26.0	26.4	27.4	28.5	26	31	0.1
Transport	55.6	48.6	46.0	44.7	44.8	51	48	-0.9
Buildings	4.7	4.7	4.7	4.7	4.6	4	5	-0.1
Agriculture	3.7	2.8	2.6	2.5	2.4	3	3	-1.7
$PM_{2.5}$ emissions from all energy activities (Mt)								
Total	**30.8**	**28.9**	**28.5**	**28.7**	**28.7**	**100**	**100**	**-0.3**
Power	1.9	1.3	1.2	1.3	1.3	6	4	-1.5
Industry*	8.7	9.1	9.5	10.2	10.8	28	38	0.9
Transport	2.5	2.3	2.3	2.4	2.6	8	9	0.1
Buildings	16.9	15.5	14.7	14.1	13.4	55	47	-0.9
Agriculture	0.8	0.7	0.7	0.7	0.7	3	2	-0.5

** Industry also includes other transformation.*

	Emissions of pollutants by fuel					Shares (%)		CAAGR (%)
	2015	2025	2030	2035	2040	2015	2040	2015-40
SO_2 emissions from combustion activities (Mt)								
Total	**59.1**	**42.4**	**37.8**	**37.8**	**38.4**	**100**	**100**	**-1.7**
Coal	34.0	25.0	20.2	20.3	20.6	57	54	-2.0
Oil	22.9	14.7	14.7	14.3	14.2	39	37	-1.9
Gas	0.3	0.4	0.5	0.5	0.6	1	2	2.4
Bioenergy	1.9	2.3	2.4	2.7	3.1	3	8	1.9
NO_X emissions from combustion activities (Mt)								
Total	**95.8**	**83.0**	**79.8**	**78.8**	**80.2**	**100**	**100**	**-0.7**
Coal	16.9	12.1	11.6	10.9	10.9	18	14	-1.7
Oil	66.4	57.3	53.8	52.1	51.9	69	65	-1.0
Gas	8.9	9.4	10.0	11.1	12.4	9	15	1.3
Bioenergy	3.6	4.1	4.4	4.7	5.0	4	6	1.4
$PM_{2.5}$ emissions from combustion activities (Mt)								
Total	**24.0**	**21.3**	**20.3**	**19.8**	**19.2**	**100**	**100**	**-0.9**
Coal	4.3	3.2	2.8	2.6	2.5	18	13	-2.2
Oil	3.8	2.9	2.7	2.7	2.7	16	14	-1.3
Gas	0.1	0.1	0.1	0.1	0.2	0	1	1.9
Bioenergy	15.8	15.1	14.7	14.3	13.9	66	72	-0.5

World: Current Policies and Sustainable Development Scenarios

	Emissions of pollutants by energy sector						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2015-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
SO_2 emissions from all energy activities (Mt)										
Total	**64.1**	**61.1**	**65.4**	**48.7**	**36.5**	**17.8**	**100**	**100**	**-0.8**	**-5.8**
Power	18.9	16.1	18.0	13.0	8.0	1.6	28	9	-1.5	-10.6
Industry*	34.7	34.5	36.4	28.2	22.7	12.8	56	72	0.1	-4.0
Transport	4.1	4.5	5.3	2.9	2.6	2.0	8	11	-2.5	-6.3
Buildings	5.1	4.8	4.3	3.7	2.5	1.1	7	6	-1.2	-6.6
Agriculture	1.3	1.3	1.3	1.0	0.7	0.3	2	1	0.0	-6.1
NO_X emissions from all energy activities (Mt)										
Total	**100.6**	**102.0**	**111.7**	**78.6**	**66.0**	**46.5**	**100**	**100**	**0.1**	**-3.3**
Power	13.2	13.5	16.0	9.6	7.3	2.2	14	5	-0.1	-7.7
Industry*	26.5	27.1	29.8	22.1	18.9	13.0	27	28	0.3	-3.0
Transport	53.2	53.7	58.3	40.6	34.7	27.5	52	59	0.2	-2.8
Buildings	4.8	4.9	5.0	3.6	2.8	2.0	4	4	0.2	-3.4
Agriculture	2.9	2.8	2.7	2.6	2.3	1.8	2	4	-1.2	-2.7
$PM_{2.5}$ emissions from all energy activities (Mt)										
Total	**29.3**	**29.0**	**29.8**	**18.6**	**12.3**	**5.8**	**100**	**100**	**-0.1**	**-6.5**
Power	1.4	1.3	1.5	1.0	0.7	0.1	5	2	-0.8	-9.9
Industry*	9.2	9.6	11.1	7.2	5.6	2.1	37	37	1.0	-5.4
Transport	2.3	2.4	2.8	2.1	2.0	2.1	10	36	0.4	-0.8
Buildings	15.6	14.9	13.6	7.7	3.5	1.1	46	19	-0.9	-10.4
Agriculture	0.7	0.7	0.8	0.6	0.5	0.3	3	5	-0.3	-3.9

** Industry also includes other transformation.*

	Emissions of pollutants by fuel						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2015-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
SO_2 emissions from combustion activities (Mt)										
Total	**45.0**	**41.3**	**44.4**	**32.3**	**22.3**	**8.8**	**100**	**100**	**-1.1**	**-7.3**
Coal	26.8	22.7	25.2	18.7	11.2	3.1	57	35	-1.2	-9.2
Oil	15.4	15.8	15.9	11.3	8.6	3.5	36	39	-1.5	-7.3
Gas	0.4	0.5	0.6	0.4	0.5	0.5	1	6	2.7	1.9
Bioenergy	2.2	2.4	2.7	1.8	2.1	1.8	6	20	1.4	-0.3
NO_X emissions from combustion activities (Mt)										
Total	**89.1**	**90.0**	**98.5**	**68.3**	**56.6**	**39.2**	**100**	**100**	**0.1**	**-3.5**
Coal	13.1	13.1	13.7	9.1	6.3	2.1	14	5	-0.9	-8.0
Oil	62.3	62.2	66.4	47.9	40.3	31.2	67	80	-0.0	-3.0
Gas	9.6	10.4	13.6	8.1	7.1	3.5	14	9	1.7	-3.7
Bioenergy	4.1	4.4	4.9	3.2	2.9	2.4	5	6	1.3	-1.6
$PM_{2.5}$ emissions from combustion activities (Mt)										
Total	**21.7**	**20.8**	**20.2**	**12.5**	**7.1**	**3.0**	**100**	**100**	**-0.7**	**-8.0**
Coal	3.4	3.2	3.2	2.4	1.5	0.3	16	11	-1.2	-9.8
Oil	3.0	2.9	3.1	2.5	2.0	1.6	15	53	-0.9	-3.4
Gas	0.1	0.1	0.2	0.1	0.1	0.1	1	4	2.2	0.5
Bioenergy	15.1	14.6	13.8	7.4	3.5	1.0	68	33	-0.6	-10.5

Policies and measures by scenario

World Energy Outlook-2017 (*WEO-2017*) presents projections for three core scenarios, which are differentiated primarily by their underlying assumptions about the evolution of energy-related government policies.

The ***New Policies Scenario*** (NPS) is the central scenario of this *Outlook*, and aims to provide a sense of the direction in which latest policy ambitions could take the energy sector. In addition to incorporating policies and measures that governments around the world have already put in place, it also takes into account the effects of announced policies, as expressed in official targets and plans. The Nationally Determined Contributions of the Paris Agreement provide important guidance regarding policy intentions, although some have been supplemented or superseded by more recent announcements. Given that "new policies" are by definition not yet fully reflected in legislation or regulation, the prospects and timing for their full realisation are based upon our assessment of the relevant political, regulatory, market, infrastructural and financial constraints.

The ***Current Policies Scenario*** (CPS) considers the impact of only those policies and measures that are firmly enshrined in legislation as of mid-2017. In addition, where existing policies target a range of outcomes, it is assumed that the lower end of the range is achieved. In this way, CPS provides a cautious assessment of where existing policies might lead the energy sector in the absence of additional impetus from governments. It provides a benchmark against which the impact of "new policies" can be measured.

The ***Sustainable Development Scenario*** (SDS) is introduced for the first time in *WEO-2017*. It builds on the Sustainable Development Goals (SDGs) of the United Nations and aims to provide an energy sector pathway that integrates three closely associated but distinct policy objectives: to ensure universal access to affordable, reliable and modern energy services by 2030 (SDG 7.1); to substantially reduce the air pollution which causes deaths and illness (SDG 3.9); and to take effective action to combat climate change (SDG 13). The objective of the SDS is to lay out an integrated strategy for the achievement of these important policy objectives, alongside energy security, in order to show how the respective objectives can be reconciled, dealing with potentially conflicting priorities, so as to realise mutually-supportive benefits.

The key policies assumed to be adopted in each of the main scenarios of *WEO-2017* are presented by sector and region. The policies are cumulative: measures listed under the SDS supplement those under the NPS, which in turn supplement policies under the CPS. The tables below begin with broad cross-cutting policy frameworks, followed by more detailed policies by sector: power, transport, industry and buildings.

Table B.1 ▷ Cross-cutting policy assumptions by scenario for selected regions

	Scenario	Assumptions
All regions	CPS	• Fossil-fuel subsidies phased out in countries that already have relevant policies in place.
	NPS	• Fossil-fuel subsidies phased out in the next ten years in all net-importing countries, and in net-exporting countries where specific policies have been announced.
	SDS	• Universal access to electricity and clean cooking facilities by 2030. • Staggered introduction of CO_2 prices in all advanced economies. • Fossil-fuel subsidies phased out by 2025 in net-importers and by 2035 in net-exporters. • Maximum sulfur content of oil products capped at 0.5% for heavy fuel oil, 0.1% for gasoil and 50 ppm for gasoline and diesel.
United States	CPS	• State-level renewable portfolio standards with the option of using energy efficiency as a means of compliance. • Regional Greenhouse Gas Initiative: mandatory cap-and-trade scheme covering fossil-fuel power plants in nine northeast states. • Economy-wide cap-and-trade scheme in California with binding commitments.
Japan	NPS	• NDC targets: economy-wide target of reducing GHG emissions by 26% below fiscal year 2013 levels by fiscal year 2030; sector-specific targets.
European Union	CPS	• 2020 Climate and Energy Package: o Reduce GHG emissions 20% below 1990 levels. o Increase share of renewables to at least 20%. o Partial implementation of 20% energy savings. • ETS reducing GHG emissions 21% below 2005 level in 2020.
	NPS	• NDC targets and 2030 Climate and Energy Framework: o Reduce GHG emissions 40% below 1990 levels. o Increase share of renewables to at least 27%. o Save 27% of energy use compared with business-as-usual scenarios. • ETS reducing GHG emissions 43% below the 2005 level in 2030. • National Emission Ceilings Directive to reduce emissions of SO_2 by 79%, NO_X by 63%, $PM_{2.5}$ by 49%, NMVOC by 40% and NH_3 by 19% below 2005 levels by 2030. • Increase share of renewables in heating and cooling by 1% per year to 2030.
Russia	NPS	• NDC target: limit GHG emissions to 70-75% of 1990 levels by 2030.
China	CPS	• Action Plan for Prevention and Control of Air Pollution.
	NPS	• NDC GHG targets: achieve peak CO_2 emissions around 2030, with best efforts to peak early; lower CO_2 emissions per unit of GDP 60-65% below 2005 levels by 2030. • NDC energy target: increase the share of non-fossil fuels in primary energy consumption to 20% by 2030. • 13th Five-Year Plan targets for 2020: o Services sector value to be increased to 56%. o Non-fossil fuels to reach 15% of TPED. o Energy intensity per unit of GDP limited to 15% below 2015 levels. o Carbon emissions per unit of GDP limited to 18% below 2015 levels. o SO_2 and NO_X emissions reduced by 15%. • "Made in China 2025" transition from heavy industry to higher value-added manufacturing. • Expand the role of natural gas. • ETS covering power and selected industry sectors from 2017. • Energy price reform, including more frequent adjustments in oil product prices and reduction in natural gas price for non-residential consumers.

Table B.1 ▹ Cross-cutting policy assumptions by scenario for selected regions (continued)

	Scenario	Assumptions
India	CPS	• National Mission on Enhanced Energy Efficiency. • National Clean Energy Fund to promote clean energy technologies based on a levy of INR 400 (USD 6) per tonne of coal. • "Make in India" campaign to increase the share of manufacturing in the national economy.
	NPS	• NDC GHG target: reduce emissions intensity of GDP 33-35% below 2005 levels by 2030. • NDC energy target: achieve about 40% cumulative installed capacity from non-fossil fuel sources by 2030 with the help of technology transfer and low-cost international finance. • Efforts to expedite environmental clearances and land acquisition for energy projects. • Open the coal sector to private and foreign investors.
Brazil	NPS	• NDC GHG targets: reduce GHG emissions 37% below 2005 levels by 2025. • NDC energy targets for 2030: o Increase share of sustainable biofuels to around 18% of TPED. o Increase renewables to 45% of TPED. o Increase non-hydro renewables to 28-30% of TPED and 23% of power supply. • Partial implementation of National Energy Efficiency Plan.

Notes: NDC = Nationally Determined Contributions; GHG = greenhouse gases; LPG = liquefied petroleum gas; SO_2 = sulfur dioxide; NO_X = nitrogen oxides; $PM_{2.5}$ = fine particulate matter; NMVOC = non-methane volatile organic compounds; NH_3 = ammonia; TPED = total primary energy demand; ETS = emissions trading system. Pricing of CO_2 emissions is by emissions trading systems or taxes.

Table B.2 ▷ Power sector policies and measures as modelled by scenario for selected regions

	Scenario	Assumptions
All regions	SDS	• Increased low-carbon generation from renewables and nuclear. • Expanded support for the deployment of CCS. • Efficiency and emissions standards preventing the refurbishment of old inefficient plants. • Stringent emissions limits for industrial facilities above 50 MW_{th} input using solid fuels, set at 200 mg/m^3 for SO_2 and NO_X and 30 mg/m^3 for $PM_{2.5}$. • RD&D on innovative technologies and support to innovative market designs.
United States	CPS	• Extension of Investment Tax Credit and Production Tax Credit. • State renewable portfolio standards and support for renewables. • Mercury and Air Toxics Standards. • New Source Performance Standards. • Clean Air Interstate Rule regulating SO_2 and NO_X. • Lifetimes of some nuclear plants extended beyond 60 years. • Funding for CCS at demonstration scale.
	NPS	• Extension and strengthening of support for renewables. • Increased support for renewables, nuclear and CCS.
Japan	CPS	• Air Pollution Control Law. • Retail power market liberalisation. • Support for renewables-based power generation.
	NPS	• Achievement of the power mix target by 2030 (renewables: 22-24%, nuclear power: 20-22%, gas: 27%, coal: 26%, oil: 3%). • Lifetime of nuclear plants typically extended to 40 years, with possible extensions to 60 years. • Non-fossil fuels to supply 44% of power generation by 2030, corresponding to carbon intensity of 370 g CO_2/kWh. • Implementation of the feed-in tariff amendment law. • Efficiency standards for new thermal power plants (coal: 42%, gas: 50.5%, oil: 39%).
European Union	CPS	• ETS in accordance with 2020 Climate and Energy Package. • No new coal power plants post-2020 in 26 of 28 member states. • Early retirement of all nuclear plants in Germany by end-2022. • Removal of some barriers to CHP plants. • Support for renewables in accordance with overall target. • Industrial Emissions Directive.
	NPS	• ETS in accordance with 2030 Climate and Energy Framework. • Reduction of nuclear share in France to 50% of output. • Extended and strengthened support to renewables-based power generation technologies in accordance with overall target. • Further removal of barriers to CHP through partial implementation of the Energy Efficiency Directive. • Power market reforms to enable recovery of investments for adequacy.
Russia	CPS	• Competitive wholesale electricity market.
	NPS	• State support to hydro and nuclear. • Strengthened and broadened support mechanisms for non-hydro renewables.

Table B.2 ▷ Power sector policies and measures as modelled by scenario for selected regions (continued)

	Scenario	Assumptions
China	CPS	• Air pollutant emissions standard for thermal power plants with limits on $PM_{2.5}$: 30 mg/m^3; SO_2: 100-200 mg/m^3 for new plants and 200-400 mg/m^3 for existing plants; NO_X: 100-200 mg/m^3.
	NPS	• ETS in force from 2017. • 13th Five-Year Plan targets for 2020: o 58 GW nuclear, 380 GW hydro, at least 210 GW wind and at least 110 GW solar. o Retrofit of 133 GW of CHP and 86 GW of condensing coal plants in order to increase flexibility. o Coal limited to 1 100 GW, by delaying 150 GW of new builds and retiring 20 GW of existing plants.
India	CPS	• Renewable Purchase Obligation and other fiscal measures to promote renewables. • Increased use of supercritical coal technology. • Restructured Accelerated Power Development and Reform Programme to finance the modernisation of transmission and distribution networks.
	NPS	• Environmental (Protection) Amendment Rules. • Universal electricity access achieved by 2025. • Strengthened measures such as competitive bidding to increase the use of renewables towards the national target of 175 GW of renewables capacity by 2022 (100 GW solar, 75 GW non-solar). • Expanded efforts to strengthen the national grid, upgrade the transmission and distribution network and reduce aggregate technical and commercial losses to 15%. • Increased efforts to establish the financial viability of all power market participants, especially network and distribution companies.
Brazil	CPS	• Power auctions for all fuel types. • Guidance on fuel mix from the Ten-Year Plan for Energy Expansion.

Notes: CCS = carbon capture and storage; CHP = combined heat and power; SO_2 = sulfur dioxide; NO_X = nitrogen oxides; $PM_{2.5}$ = fine particulate matter; g CO_2/kWh = grammes of carbon dioxide per kilowatt-hour; GW = gigawatts; PV = photovoltaic; ETS = emissions trading system; RD&D = research, development, and demonstration.

Table B.3 ▷ Transport sector policies and measures as modelled by scenario in selected regions

	Scenario	Assumptions
All regions	NPS	• Road transport: fuel sulfur standards of 10-15 ppm. • Aviation: ICAO goal to improve fuel efficiency by 2% per year until 2020; aiming for carbon-neutral growth from 2020 onwards. • Maritime transport: global cap of 0.5% on fuel sulfur content in 2020 and tightened NO_X emissions standards in control areas by 2025.
	SDS	• Strong support for electric mobility and enhanced support to alternative fuels. • PLDVs: on-road stock emissions intensity limited to 55 g CO_2/km in advanced economies and 75 g CO_2/km elsewhere by 2040. • Two/three-wheelers: phase-out of two-stroke engines. • Light-duty gasoline vehicles: three-way catalysts and tight evaporative controls required. • Light-duty diesel vehicles: limit emissions to 0.1 g/km NO_X and 0.01 g/km PM. • Light commercial vehicles: full technology spill-over from PLDVs. • Medium- and heavy-freight vehicles: 30% more efficient by 2040 than in the NPS. • Heavy-duty diesel vehicles: limit emissions to 3.5 g/km NO_X and 0.03 g/km PM. • Aviation: fuel intensity reduced by 2.6% per year; scale-up of biofuels to reduce CO_2 emissions by 50% below 2005 levels in 2050. • Maritime transport: increased oil-to-gas switching and use of low-sulfur fuels. • Retail fuel prices kept at a level similar to the NPS.
United States	CPS	• Renewables Fuel Standard 2. • PLDVs: CAFE standards requiring 33 miles per gallon by 2017. • LDVs: Tier 3 emissions standards, EURO 6 fuel sulfur standards. • HDVs: US 2010 emissions standards, EURO VI fuel sulfur standards. • Trucks: average on-road fuel consumption to be reduced by up to 18% in 2018.
	NPS	• Moderate increase of ethanol blending mandates. • PLDVs: CAFE standards requiring 54.5 miles per gallon by 2025. • EVs: stock target of 5 million by 2025 across eight states. • Trucks: CO_2 and fuel consumption reduced by 16% for heavy-duty pickup trucks and vans, 16-19% for vocational vehicles, and up to 30% for tractor-trailers in 2018-2027. • Road freight: support for natural gas.
Japan	CPS	• Financial incentives for plug-in hybrid, electric and fuel-cell vehicles. • PLDVs: fuel economy target at 20.3 kilometres per litre (km/l) by 2020. • Post New Long-Term Emissions Standards for LDVs and HDVs equivalent to Euro 6/VI.
	NPS	• Target sales share of next generation vehicles (clean diesel, hybrid, plug-in hybrid, electric and fuel-cell vehicles) of 50-70% by 2030. • EVs: stock target of 1 million by 2020, including purchase incentives and government support for charging installation costs.
European Union	CPS	• Subsidy support to biofuels blending, 7% cap on conventional biofuels blending rate. • LDVs: Euro 6 emissions and fuel sulfur standards. • HDVs: Euro VI emissions and fuel sulfur standards. • Domestic aviation: ETS.
	NPS	• Announcements to phase out gasoline and diesel car sales including France, Norway, the Netherlands, and the United Kingdom. • Increase renewables-based fuels to 10% of transport energy demand by 2020. • Fuel Quality Directive, reducing GHG intensity of road transport fuels by 6% in 2020. • PLDVs: emissions target at 95 g CO_2/km by 2021; • Commercial LDVs: emissions target at 147 g CO_2/km by 2020. • EVs: enhanced support to alternative fuels and vehicle powertrains, including sales and stock share targets for EVs, but limited role for food-based biofuels. • Domestic aviation: ETS in accordance with 2030 Climate and Energy Framework.

Table B.3 ▷ Transport sector policies and measures as modelled by scenario in selected regions (continued)

	Scenario	Assumptions
China	CPS	• Ethanol and biodiesel blending mandates of 10% and 7% respectively in some provinces. • Promotion of fuel-efficient cars. • Subsidies for hybrid cars and EVs; consolidation of vehicle charging standards. • PLDVs: cap on sales in some cities to reduce air pollution and traffic. • LDVs: China 5 emissions standards and EURO 6 equivalent fuel sulfur standards. • HDVs: China V (diesel) emissions standards and EURO VI equivalent fuel sulfur standards.
	NPS	• Extended subsidies for alternative-fuel vehicles, mainly electric scooters and buses. • Electric PVs: stock target of 5 million by 2020, including purchase and use incentives and a sales target of 5 million in 2025. • Declared intent to fully phase-out gasoline and diesel car sales. • PLDVs: fuel economy target at 5 litres per 100 km by 2020, and ambitions for 4 litres per 100 km by 2025; China 6 emission standards from 2020. • HDVs: fuel-economy standards. • Promotion of public transport in large and medium cities.
India	CPS	• Increasing blending mandate for ethanol. • Support for alternative-fuel vehicles. • LDVs: Bharat IV emissions standards and EURO 4 equivalent fuel sulfur standards, • HDVs: Bharat IV emissions standards and EURO IV equivalent fuel sulfur standards.
	NPS	• Declared intent to move to full electrification of vehicle sales by 2030. • Extended support for alternative-fuel vehicles, including 2020 National Electric Mobility Mission Plan; subsequent support for electric two/three-wheelers, cars and buses. • Continued efforts to increase blending mandates for bioethanol and biodiesel. • PLDVs: Bharat VI emissions standards by 2020; fuel-economy standards at 130 g CO_2/km in 2017 and 113 g CO_2/km in 2022. • HDVs: Bharat VI emissions standards by 2020; fuel-economy targets for 2018 and 2021. • Increased support for natural gas in road transport, particularly urban public transport. • Dedicated rail corridors to encourage shift away from road freight.
Brazil	CPS	• Ethanol blending mandates in road transport of minimum 27%. • Biodiesel blending mandate of 8% in 2017, 9% in 2018 and 10% in 2019. • LDVs: L-6 emissions standards; EURO 2 (gasoline) and EURO 4 (diesel) equivalent fuel sulfur standards. • HDVs: P-7 emissions standards; EURO II (gasoline) and EURO IV (diesel) equivalent fuel sulfur standards.
	NPS	• Further increase of ethanol and biodiesel blending mandates. • PLDVs: Inovar-Auto initiative targeting fuel efficiency improvement of at least 12% in 2017, compared with 2012-13. • Local renewables-based fuel targets for urban transport. • National urban mobility plan. • Long-term plan for freight transport.

Notes: ICAO = International Civil Aviation Organization; ppm = parts per million; NO_x = nitrogen oxides; g/km = grammes per kilometre; PM = particulate matter; CAFE = Corporate Average Fuel Economy; PLDVs = passenger light-duty vehicles; LDVs = light-duty vehicles; HDVs = heavy-duty vehicles; EVs = electric vehicles; GHG = greenhouse gases; CO_2/km = grammes of carbon dioxide per kilometre; ETS = emissions trading system.

Table B.4 ▷ Industry sector policies and measures as modelled by scenario in selected regions

	Scenario	Assumptions
All regions	SDS	• Stringent emissions limits for industrial facilities above 50 MW_{th} input using solid fuels, set at 200 mg/m^3 for NO_X and SO_2 and 30 mg/m^3 for $PM_{2.5}$. • Emission limits for facilities below 50 MW_{th} based on size, fuel and combustion process. • Industrial processing plants to be fitted with the best available technologies in order to obtain operating permits. Existing plants to be retrofitted within ten years. • Enhanced minimum energy performance standards by 2025, in particular for electric motors; incentives for the introduction of variable speed drives in variable load systems, and implementation of system-wide measures. • International agreements on steel and cement industry energy intensity targets. • Mandatory energy management systems or energy audits. • Policies to support the introduction of CCS in industry. • Wider hosting of international projects to offset CO_2 emissions.
United States	CPS	• Better Buildings, Better Plants Programme and Energy Star Programme for Industry. • Boiler Maximum Achievable Control Technology to impose stricter emissions limits on industrial and commercial boilers, and process heaters. • Superior Energy Performance certification that supports the introduction of energy management systems. • Industrial Assessment Centers providing no-cost energy assessments to SMEs. • Permit programme for GHGs and other air pollutants for large industrial installations. • Business Energy Investment Tax Credit and funding for efficient technologies.
	NPS	• Continuation of tax reduction and funding for efficient technologies and strengthened research and development in low-carbon technologies. • Further assistance for SME manufacturers to adopt “smart manufacturing technologies” through technical assistance and grant programmes.
Japan	CPS	• Energy efficiency benchmarking. • Tax credits for investments in energy efficiency. • Financial incentives for SMEs to invest in energy conserving equipment and facilities. • Free energy audits for SMEs. • Mandatory energy management for large business operators. • Top Runner Programme of minimum energy standards for machinery and equipment.
	NPS	• Maintenance and strengthening of top-end low-carbon efficiency standards: o Higher efficiency CHP systems. o Promotion of state-of-the-art technology, faster replacement of ageing equipment. o Continuation of voluntary ETS.
European Union	CPS	• ETS in accordance with 2020 Climate and Energy Package. • White certificate scheme in Italy and energy saving obligation scheme in Denmark. • Voluntary energy efficiency agreements in Belgium, Denmark, Finland, Hungary, Ireland, Luxembourg, Netherlands, Portugal, Sweden and United Kingdom. • Ecodesign Directive standards for motors, pumps, fans, compressors and insulation. • Implementation of Medium Combustion Plant Directive. • Industrial Emissions Directive.
	NPS	• ETS in accordance with 2030 Climate and Energy Framework. • Implementation of Energy Efficiency Directive and extension to 2030: o Mandatory and regular energy audits for large enterprises. o Incentives for the use of energy management systems. o Encouragement for SMEs to undergo energy audits. o Technical assistance and targeted information for SMEs.

Table B.4 ▷ Industry sector policies and measures as modelled by scenario in selected regions (continued)

	Scenario	Assumptions
Russia	CPS	• Competitive wholesale electricity market price. • Investment tax credit for energy-efficient technologies and projects. • Regional energy savings programmes, providing subsidies and governmental guarantees. • Complete phase-out of open hearth furnaces in the iron and steel industry.
	NPS	• Energy audits for large industry and tax incentives for new, highly energy-efficient assets. • Limited phase-out of natural gas subsidy to domestic consumers.
China	CPS	• Accelerated elimination of outdated production capacity. • Partial implementation of Industrial Energy Performance Standards. • Mandatory adoption of coke dry-quenching and top-pressure turbines in new iron and steel plants. Support of non-blast furnace in iron production. • Mechanism to incentivise energy-efficient "leaders", i.e. manufacturers and brands that exceed specific benchmarks set by the China Energy Label. • Pilot of China's ETS for some provinces and industrial sectors.
	NPS	• Accelerated retrofit of older coal-fired industrial boilers. • Expansion of ETS in accordance with overall target. • "Made in China 2025" targets for industrial energy intensity. • Continuation of industrial energy intensity reduction contributing to the 13th Five-Year Plan target (2016-20). • Full implementation of Industrial Energy Performance Standards. • Enhanced use of energy service companies and energy performance contracting.
India	CPS	• Energy Conservation Act: o Mandatory energy audits. o Appointment of an energy manager in seven energy-intensive industries. • National Mission on Enhanced Energy Efficiency (NMEEE): o Cycle II and III of Perform, Achieve and Trade (PAT) scheme, which benchmarks facilities' performance against best practice and enables trading of energy savings certificates. o Income and corporate tax incentives for energy service companies, including the Energy Efficiency Financing Platform. o Framework for Energy-Efficient Economic Development offering a risk guarantee for performance contracts and a venture capital fund for energy efficiency. • Energy efficiency intervention in selected SME clusters including capacity building.
	NPS	• Further implementation of the NMEEE's recommendations including: o Tightening of the PAT mechanism under Cycle III. o Further strengthening of fiscal instruments to promote energy efficiency. • Strengthen existing policies to realise the energy efficiency potential in SMEs.
Brazil	CPS	• PROCEL (National Programme for Energy Conservation). • PROESCO (Support for Energy Efficiency Projects). • Incentives to increase biomass use in industry.
	NPS	• Partial implementation of the National Energy Efficiency Plan, with fiscal and tax incentives for industrial upgrading, investment in training efficiency and encouragement to reuse industrial waste. • Extension of PROESCO.

Notes: CCS = carbon capture and storage; MW_{th} = megawatts thermal; mg/m³ = milligrams per cubic metre; ETS = emissions trading system; SO_2 = sulfur dioxide; NO_X = nitrogen oxides; PM = particulate matter; CHP = combined heat and power; SMEs = small and medium enterprises.

Table B.5 ▷ Buildings sector policies and measures as modelled by scenario in selected regions

	Scenario	Assumptions
All regions	SDS	• SDG 7.1: universal access to affordable, reliable and modern energy achieved by 2030. • Phase-out of least efficient appliances, light bulbs and heating or cooling equipment by 2030 at the latest. • Emissions limits for biomass boilers set at 40-60 mg/m³ for PM and 200 mg/m³ for NO_X. • Introduction of mandatory energy efficiency labelling requirements for all appliances. • Mandatory energy conservation building codes, including net-zero emissions requirement for all new buildings, by 2030 at the latest. • Increased support for energy efficiency measures, direct use of solar thermal and geothermal, and heat pumps. • Digitalisation of buildings electricity demand to increase demand-side response potential, through greater flexibility and controllability of end-use devices.
United States	CPS	• Association of Home Appliance Manufacturers – American Council for an Energy-Efficient Economy Multi-Product Standards Agreement. • Energy Star: new appliance efficiency standards. • Steady upgrades of building codes; incentives for utilities to improve building efficiency. • Weatherisation programmes: funding for refurbishments of residential buildings. • Federal and state rebates for renewables-based heat, including Residential Renewable Energy Tax Credits for solar water heaters, heat pumps and biomass stoves.
	NPS	• Partial implementation of the Energy Efficiency Improvement Act of 2015. • Mandatory energy requirements in building codes in some states. • Tightening of efficiency standards for appliances.
Japan	CPS	• The Building Efficiency Act for new buildings, renovations, and extensions. • Top Runner Programme efficiency standards for home appliances. • Large operators to reduce energy consumption 1% per year and complete annual reports. • Energy efficiency standards for new buildings and houses larger than 300 m². • Capital Grant Scheme for renewable energy technologies.
	NPS	• Extension of the Top Runner Programme. • Voluntary equipment labelling programmes. • Building Energy Efficiency Act regulations for new large-scale non-residential buildings and incentives for all new buildings. • Net zero-energy buildings by 2030 for all new construction.
European Union	CPS	• Energy Performance of Buildings Directive 2010. • EcoDesign and Energy Labelling Directive including requirements for boilers to have 75-77% efficiency depending on size and to limit pollutant emissions (PM: 40-60 mg/m³; NO_X: 200 mg/m³ for biomass boilers and 350 mg/m³ for fossil-fuel boilers; CO: 500-700 mg/m³). • Individual member state financial incentives for renewables-based heat in buildings.
	NPS	• Partial implementation of the Energy Efficiency Directive. • Update of Energy Performance of Buildings Directive mandating new buildings to be nearly zero-energy by 2020. • Mandatory labelling for sale or rental of all buildings and some appliances. • Further product groups in EcoDesign Directive. • Enhanced renewables-based heat support in member states.
Russia	CPS	• Implementation of federal law on energy conservation and efficiency. • Voluntary labelling programme for electrical products.
	NPS	• New building codes, meter installations and refurbishment programmes. • Limited phase-out of natural gas and electricity subsidies.

Table B.5 ▷ Buildings sector policies and measures as modelled by scenario in selected regions (continued)

	Scenario	Assumptions
China	CPS	• Civil Construction Energy Conservation Design Standards. • Appliance standards and labelling programme.
	NPS	• Promotion of green buildings: o New urban residential buildings to increase energy efficiency by 20% from 2015 levels to 2020. o 50% of new urban buildings to meet energy conservation requirements. • Retrofit of 500 million m^2 of residential buildings and 100 million m^2 of public buildings. • Promotion of electricity to replace de-centralised coal and oil boilers. • Urban gasification of 57% by 2020. • Solar water heaters to cover 800 million m^2 by 2020. • Mandatory energy efficiency labels for appliances and equipment.
India	CPS	• Universal electricity access achieved by 2025. • Rural electrification under Deen Dayal Upadhyaya Gram Jyoti Yojana scheme. • Promotion of clean cooking access with LPG, including free connections to poor rural households through Pradhan Mantri Ujjwala Yojana. • Measures under the National Solar Mission. • Energy Conservation Building Code 2007 with voluntary standards for commercial buildings. • "Green Rating for Integrated Habitat Assessment" rating system for green buildings. • Promotion and distribution of LEDs through the Efficient Lighting Programme.
	NPS	• Standards and Labelling Programme, mandatory for air conditioners, lights, televisions, and refrigerators, voluntary for seven other products and LEDs. • Phase out incandescent light bulbs by 2020. • Voluntary Star Ratings for the services sector. • Measures under the National Mission on Enhanced Energy Efficiency. • Energy Conservation in Building Codes made mandatory in eight states that regulate building envelope, lighting and hot water. • Efforts to plan and rationalise urbanisation in line with the "100 smart cities" concept. • Enhanced efforts to increase electricity access for households.
Brazil	CPS	• Labelling programme for household goods and public buildings equipment.
	NPS	• Partial implementation of National Energy Efficiency Plan. • Mandatory certification of public lighting; ban on inefficient incandescent bulbs.

Notes: mg/m^3 = milligrams per cubic metre; SO_2 = sulfur dioxide; NO_X = nitrogen oxides; PM = particulate matter; LED = light-emitting diode; LPG = liquefied petroleum gas; HVAC = heating, ventilation and air conditioning.

Definitions

This annex provides general information on terminology used throughout *WEO-2017* including: units and general conversion factors; definitions of fuels, processes and sectors; regional and country groupings; and abbreviations and acronyms.

Units

Area	Ha	hectare
	km^2	square kilometre
Coal	Mtce	million tonnes of coal equivalent (equals 0.7 Mtoe)
	Mtpa	million tonnes per annum
	gce	grammes of coal equivalent
Emissions	ppm	parts per million (by volume)
	Gt CO_2-eq	gigatonnes of carbon-dioxide equivalent (using 100-year global warming potentials for different greenhouse gases)
	kg CO_2-eq	kilogrammes of carbon-dioxide equivalent
	g CO_2/km	grammes of carbon dioxide per kilometre
	g CO_2/kWh	grammes of carbon dioxide per kilowatt-hour
Energy	boe	barrel of oil equivalent
	toe	tonne of oil equivalent
	ktoe	thousand tonnes of oil equivalent
	Mtoe	million tonnes of oil equivalent
	MBtu	million British thermal units
	kcal	kilocalorie (1 calorie x 10^3)
	Gcal	gigacalorie (1 calorie x 10^9)
	MJ	megajoule (1 joule x 10^6)
	GJ	gigajoule (1 joule x 10^9)
	TJ	terajoule (1 joule x 10^{12})
	PJ	petajoule (1 joule x 10^{15})
	EJ	exajoule (1 joule x 10^{18})
	kWh	kilowatt-hour
	MWh	megawatt-hour
	GWh	gigawatt-hour
	TWh	terawatt-hour
Gas	mcm	million cubic metres
	bcm	billion cubic metres
	tcm	trillion cubic metres
	scf	standard cubic foot

Mass	kg	kilogramme (1 000 kg = 1 tonne)
	kt	kilotonnes (1 tonne x 10^3)
	Mt	million tonnes (1 tonne x 10^6)
	Gt	gigatonnes (1 tonne x 10^9)
	tU	tonnes of uranium
Monetary	$ million	1 US dollar x 10^6
	$ billion	1 US dollar x 10^9
	$ trillion	1 US dollar x 10^{12}
Oil	b/d	barrels per day
	kb/d	thousand barrels per day
	mb/d	million barrels per day
	mboe/d	million barrels of oil equivalent per day
Power	W	watt (1 joule per second)
	kW	kilowatt (1 watt x 10^3)
	MW	megawatt (1 watt x 10^6)
	GW	gigawatt (1 watt x 10^9)
	TW	terawatt (1 watt x 10^{12})
Water	bcm	billion cubic metres
	m^3	cubic metre

General conversion factors for energy

Convert to:	TJ	Gcal	Mtoe	MBtu	GWh
From:	multiply by:				
TJ	1	238.8	2.388 x 10^{-5}	947.8	0.2778
Gcal	4.1868 x 10^{-3}	1	10^{-7}	3.968	1.163 x 10^{-3}
Mtoe	4.1868 x 10^4	10^7	1	3.968 x 10^7	11 630
MBtu	1.0551 x 10^{-3}	0.252	2.52 x 10^{-8}	1	2.931 x 10^{-4}
GWh	3.6	860	8.6 x 10^{-5}	3 412	1

Note: There is no generally accepted definition of boe; typically conversion factors vary from 7.15 to 7.40 boe per toe.

Currency conversions

***Exchange rates** (2016 annual average)*	**1 US Dollar equals:**
British Pound	0.74
Chinese Yuan Renminbi	6.64
Euro	0.90
Indian Rupee	67.19
Indonesian Rupiah	13 308.33
Japanese Yen	108.79
Russian Ruble	67.06
South African Rand	14.71

Source: OECD National Accounts database, October 2017.

Definitions

Advanced biofuels: Sustainable fuels produced from non-food crop feedstocks, which are capable of delivering significant life-cycle greenhouse-gas emissions savings compared with fossil fuel alternatives, and which do not directly compete with food and feed crops for agricultural land or cause adverse sustainability impacts. This definition differs from the one used for "advanced biofuels" in the US legislation, which is based on a minimum 50% lifecycle greenhouse gas reduction and which, therefore, includes sugar cane ethanol.

Agriculture: Includes all energy used on farms, in forestry and for fishing.

Back-up generation capacity: Households and businesses connected to the main power grid may also have some form of "back-up" power generation capacity that can, in the event of disruption, provide electricity. Back-up generators are typically fuelled with diesel or gasoline and capacity can be from as little as a few kilowatts. Such capacity is distinct from mini-grid and off-grid systems that are not connected to the main power grid.

Biodiesel: Diesel-equivalent, processed fuel made from the transesterification (a chemical process that converts triglycerides in oils) of vegetable oils and animal fats.

Bioenergy: Energy content in solid, liquid and gaseous products derived from biomass feedstocks, biogas and waste. It includes solid biomass, biofuels and biogas.

Biofuels: Liquid fuels derived from biomass or waste feedstocks and include ethanol and biodiesel. They can be classified as conventional and advanced biofuels according to the technologies used to produce them and their respective maturity.

Biogas: A mixture of methane and carbon dioxide produced by bacterial degradation of organic matter and used as a fuel.

Buildings: The buildings sector includes energy used in residential, commercial and institutional buildings, and non-specified other. Building energy use includes space heating and cooling, water heating, lighting, appliances and cooking equipment.

Bunkers: Includes both international marine bunkers and international aviation bunkers.

Capacity credit: Proportion of the capacity that can be reliably expected to generate electricity during times of peak demand in the grid to which it is connected.

Clean cooking facilities: Cooking facilities that are considered safer, more efficient and more environmentally sustainable than the traditional facilities that make use of solid biomass (such as a three-stone fire). This refers primarily to improved solid biomass cookstoves, biogas systems, liquefied petroleum gas stoves, ethanol and solar stoves.

Coal: Includes both primary coal (including lignite, coking and steam coal) and derived fuels (including patent fuel, brown-coal briquettes, coke-oven coke, gas coke, gas-works gas, coke-oven gas, blast-furnace gas and oxygen steel furnace gas). Peat is also included.

Coalbed methane (CBM): Category of unconventional natural gas, which refers to methane found in coal seams.

Coal-to-gas (CTG): Process in which mined coal is first turned into syngas (a mixture of hydrogen and carbon monoxide) and then into "synthetic" methane.

Coal-to-liquids (CTL): Transformation of coal into liquid hydrocarbons. It can be achieved through either coal gasification into syngas (a mixture of hydrogen and carbon monoxide), combined using the Fischer-Tropsch or methanol-to-gasoline synthesis process to produce liquid fuels, or through the less developed direct-coal liquefaction technologies in which coal is directly reacted with hydrogen.

Coking coal: Type of coal that can be used for steel making (as a chemical reductant and heat source), where it produces coke capable of supporting a blast furnace charge. Coal of this quality is also commonly known as metallurgical coal.

Conventional biofuels: Fuels produced from food crop feedstocks. These biofuels are commonly referred to as first-generation and include sugar cane ethanol, starch-based ethanol, fatty acid methyl esther (FAME) and straight vegetable oil (SVO).

Decommissioning (nuclear): The process of dismantling and decontaminating a nuclear power plant at the end of its operational lifetime and restoring the site for other uses.

Decomposition analysis: Statistical approach that decomposes an aggregate indicator to quantify the relative contribution of a set of pre-defined factors leading to a change in the aggregate indicator. The *World Energy Outlook* uses an additive index decomposition of the type Logarithmic Mean Divisia Index method I (LMDI-I).

Demand-side integration (DSI): Consists of two types of measures: actions that influence load shape such as energy efficiency and electrification; and actions that manage load such as demand-side response.

Demand-side response (DSR): Describes actions which can influence the load profile such as shifting the load curve in time without affecting the total electricity demand, or load shedding such as interrupting demand for short duration or adjusting the intensity of demand for a certain amount of time.

Dispatchable generation: Refers to technologies whose power output can be readily controlled – increased to maximum rated capacity or decreased to zero – in order to match supply with demand.

Electricity generation: Defined as the total amount of electricity generated by power only or combined heat and power plants including generation required for own-use. This is also referred to as gross generation.

Energy services: Energy that is available to end-users to satisfy their needs. This is also sometimes referred to as "useful energy". Due to transformation losses the amount of useful energy is lower than the corresponding final energy. Forms of energy services include transportation, machine drive, lighting or heat for space heating.

Ethanol: Refers to bio-ethanol only. Ethanol is produced from fermenting any biomass high in carbohydrates. Today, ethanol is made from starches and sugars, but second-generation technologies will allow it to be made from cellulose and hemicellulose, the fibrous material that makes up the bulk of most plant matter.

Gas (also referred to as natural gas): Comprises gases occurring in deposits, whether liquefied or gaseous, consisting mainly of methane. It includes both "non-associated" gas originating from fields producing hydrocarbons only in gaseous form, and "associated" gas produced in association with crude oil as well as methane recovered from coal mines (colliery gas). Natural gas liquids (NGLs), manufactured gas (produced from municipal or industrial waste, or sewage) and quantities vented or flared are not included. Gas data in cubic metres are expressed on a "gross" calorific value basis and are measured at 15 °C and at 760 mm Hg ("Standard Conditions"). Gas data expressed in tonnes of oil equivalent, mainly for comparison reasons with other fuels, are on a "net" calorific basis. The difference between the "net" and the "gross" calorific value is the latent heat of vaporisation of the water vapour produced during combustion of the fuel (for gas the net calorific value is 10% lower than the gross calorific value).

Gas-to-liquids (GTL): Process featuring reaction of methane with oxygen or steam to produce syngas (a mixture of hydrogen and carbon monoxide) followed by synthesis of liquid products (such as diesel and naphtha) from the syngas using Fischer-Tropsch catalytic synthesis. The process is similar to those used in coal-to-liquids.

High-level waste (HLW): The highly radioactive and long-lived waste materials generated during the course of the nuclear fuel cycle, including spent nuclear fuel (if it is declared as waste) and some waste streams from reprocessing.

Heat (end-use): Can be obtained from the combustion of fossil or renewable fuels, direct geothermal or solar heat systems, exothermic chemical processes and electricity (through resistance heating or heat pumps which can extract it from ambient air and liquids). This category refers to the wide range of end-uses, including space and water heating, and cooking in buildings, desalination and process applications in industry. It does not include cooling applications.

Heat (supply): Obtained from the combustion of fuels, nuclear reactors, geothermal resources and the capture of sunlight. It may be used for heating or cooling, or converted into mechanical energy for transport or electricity generation. Commercial heat sold is reported under total final consumption with the fuel inputs allocated under power generation.

Hydropower: The energy content of the electricity produced in hydropower plants, assuming 100% efficiency. It excludes output from pumped storage and marine (tide and wave) plants.

Industry: Includes fuel used within the manufacturing and construction industries. Key industry branches include iron and steel, chemical and petrochemical, cement, and pulp and paper. Use by industries for the transformation of energy into another form or for the production of fuels is excluded and reported separately under other energy sector. Consumption of fuels for the transport of goods is reported as part of the transport sector, while consumption by off-road vehicles is reported under industry.

International aviation bunkers: Includes the deliveries of aviation fuels to aircraft for international aviation. Fuels used by airlines for their road vehicles are excluded. The domestic/international split is determined on the basis of departure and landing locations and not by the nationality of the airline. For many countries this incorrectly excludes fuels used by domestically owned carriers for their international departures.

International marine bunkers: Covers those quantities delivered to ships of all flags that are engaged in international navigation. The international navigation may take place at sea, on inland lakes and waterways, and in coastal waters. Consumption by ships engaged in domestic navigation is excluded. The domestic/international split is determined on the basis of port of departure and port of arrival, and not by the flag or nationality of the ship. Consumption by fishing vessels and by military forces is also excluded and included in residential, services and agriculture.

Investment: All investment data and projections reflect "overnight investment", i.e. the capital spent is generally assigned to the year production (or trade) is started, rather than the year when it actually incurs. Investments for oil, gas and coal include production, transformation and transportation; those for the power sector include refurbishments, uprates, new builds and replacements for all fuels and technologies for on-grid, mini-grid and off-grid generation, as well as investment in transmission and distribution. Investment data are presented in real terms in year-2016 US dollars.

Lignite: Type of coal that is used in the power sector mostly in regions near lignite mines due to its low energy content and typically high moisture levels, which generally makes long-distance transport uneconomic. Data on lignite in the *WEO* includes peat, a solid formed from the partial decomposition of dead vegetation under conditions of high humidity and limited air access.

Lignocellulosic feedstock: Crops cultivated to produce biofuels from their cellulosic or hemicellulosic components, which include switchgrass, poplar and miscanthus.

Liquid fuels: The classification of liquid fuels used in our analysis is presented in Figure C.1. Natural gas liquids accompanying tight oil or shale gas production are accounted together with other NGLs under conventional oil.

Lower heating value: Heat liberated by the complete combustion of a unit of fuel when the water produced is assumed to remain as a vapour and the heat is not recovered.

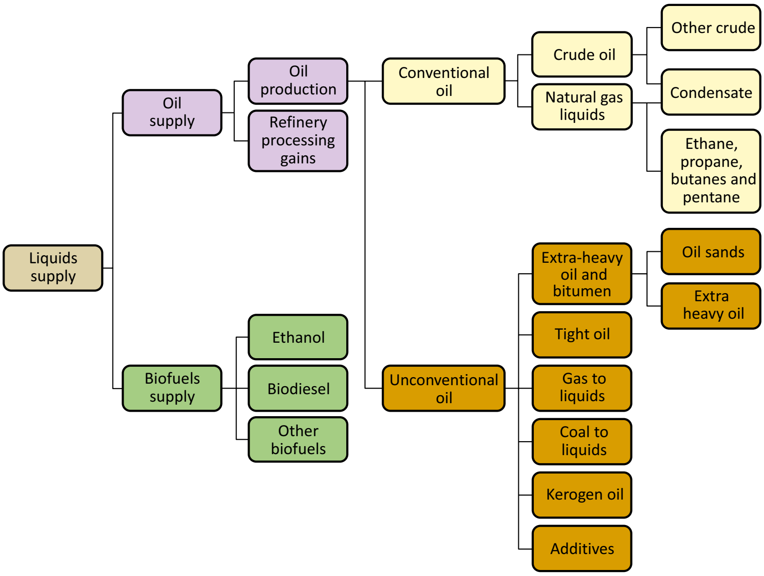
Middle distillates: Include jet fuel, diesel and heating oil.

Mini-grids: Small grid systems linking a number of households or other consumers.

Modern energy access: Includes household access to a minimum level of electricity; household access to safer and more sustainable cooking and heating fuels and stoves; access that enables productive economic activity; and access for public services.

Modern renewables: Includes all uses of renewable energy with the exception of traditional use of solid biomass.

Figure C.1 ▷ Liquid fuels classification



Modern use of solid biomass: Refers to the use of solid biomass in improved cookstoves and modern technologies using processed biomass such as pellets.

Natural gas liquids (NGLs)**:** Liquid or liquefied hydrocarbons produced in the manufacture, purification and stabilisation of natural gas. These are those portions of natural gas which are recovered as liquids in separators, field facilities or gas processing plants. NGLs include but are not limited to ethane (when it is removed from the natural gas stream), propane, butane, pentane, natural gasoline and condensates.

Non-energy use: Fuels used for chemical feedstocks and non-energy products. Examples of non-energy products include lubricants, paraffin waxes, asphalt, bitumen, coal tars and oils as timber preservatives.

Nuclear: Refers to the primary energy equivalent of the electricity produced by a nuclear plant, assuming an average conversion efficiency of 33%.

Off-grid systems: Stand-alone systems for individual households or groups of consumers.

Oil: Oil production includes both conventional and unconventional oil (Figure C.1). Petroleum products include refinery gas, ethane, liquid petroleum gas, aviation gasoline, motor gasoline, jet fuels, kerosene, gas/diesel oil, heavy fuel oil, naphtha, white spirit, lubricants, bitumen, paraffin, waxes and petroleum coke.

Other energy sector: Covers the use of energy by transformation industries and the energy losses in converting primary energy into a form that can be used in the final consuming sectors. It includes losses by gas works, petroleum refineries, blast furnaces, coke ovens, coal and gas transformation and liquefaction. It also includes energy used in coal mines, in oil and gas extraction and in electricity and heat production. Transfers and statistical differences are also included in this category.

Power generation: Refers to fuel use in electricity plants, heat plants and combined heat and power (CHP) plants. Both main activity producer plants and small plants that produce fuel for their own use (auto-producers) are included.

Pre-salt oil and gas: These resources are referred to as such because they predate the formation of a thick salt layer, which overlays the hydrocarbons and traps them in place.

Productive uses: Energy used towards an economic purpose: agriculture, industry, services, and non-energy use. Some energy demand from the transport sector (e.g. freight-related) could also be considered as productive, but is treated separately.

Renewables: Includes bioenergy, geothermal, hydropower, solar photovoltaics (PV), concentrating solar power (CSP), wind and marine (tide and wave) energy for electricity and heat generation.

Residential: Energy used by households including space heating and cooling, water heating, lighting, appliances, electronic devices and cooking equipment.

Resistance heating: Refers to direct electricity transformation into heat through the joule effect.

Self-sufficiency: Corresponds to indigenous production divided by total primary energy demand.

Services: Energy used in commercial (e.g. hotels, offices, catering, shops) and institutional buildings (e.g. schools, hospitals, offices). Services energy use includes space heating and cooling, water heating, lighting, equipment, appliances and cooking equipment.

Shale gas: Natural gas contained within a commonly occurring rock classified as shale. Shale formations are characterised by low permeability, with more limited ability of gas to flow through the rock than is the case with a conventional reservoir. Shale gas is generally produced using hydraulic fracturing.

Solid biomass: Includes charcoal, fuelwood, dung, agricultural residues, wood waste and other solid wastes.

Steam coal: Type of coal that is mainly used for heat production or steam-raising in power plants and, to a lesser extent, in industry. Typically, steam coal is not of sufficient quality for steel making. Coal of this quality is also commonly known as thermal coal.

Tight oil: Oil produced from shales or other very low permeability formations, using hydraulic fracturing. This is also sometimes referred to as light tight oil.

Total final consumption (TFC): Is the sum of consumption by the different end-use sectors. TFC is broken down into energy demand in the following sectors: industry (including manufacturing and mining), transport, buildings (including residential and services) and other (including agriculture and non-energy use). It excludes international marine and aviation bunkers, except at world level where it is included in the transport sector.

Total primary energy demand (TPED): Represents domestic demand only and is broken down into power generation, other energy sector and total final consumption.

Traditional use of solid biomass: Refers to the use of solid biomass with basic technologies, such as a three-stone fire, often with no or poorly operating chimneys.

Transport: Fuels and electricity used in the transport of goods or persons within the national territory irrespective of the economic sector within which the activity occurs. This includes fuel and electricity delivered to vehicles using public roads or for use in rail vehicles; fuel delivered to vessels for domestic navigation; fuel delivered to aircraft for domestic aviation; and energy consumed in the delivery of fuels through pipelines. Fuel delivered to international marine and aviation bunkers is presented only at the world level and is excluded from the transport sector at the domestic level.

Variable renewable energy (VRE): Refers to technologies whose maximum output at any time depends on the availability of fluctuating renewable energy resources. VRE includes a broad array of technologies such as wind power, solar PV, run-of-river hydro, concentrating solar power (where no thermal storage is included) and marine (tidal and wave).

Waste storage and disposal: Activities related to the management of radioactive nuclear waste. Storage refers to temporary facilities at the nuclear power plant site or a centralised site. Disposal refers to permanent facilities for the long-term isolation of high-level waste, such as deep geologic repositories.

Water consumption: The volume of water withdrawn that is not returned to the source (i.e. it is evaporated or transported to another location) and by definition is no longer available for other uses.

Water sector: Includes all processes whose main purpose is to treat/process or move water to or from the end-use: groundwater and surface water extraction, long-distance water transport, water treatment, desalination, water distribution, wastewater collection, wastewater treatment and water re-use.

Water withdrawal: The volume of water removed from a source; by definition withdrawals are always greater than or equal to consumption.

Regional and country groupings

Advanced economies: OECD regional grouping and Bulgaria, Croatia, Cyprus[1,2], Latvia, Lithuania, Malta and Romania.

Africa: North Africa and sub-Saharan Africa regional groupings.

Asia Pacific: Southeast Asia regional grouping and Australia, Bangladesh, China, Chinese Taipei, India, Japan, Korea, Democratic People's Republic of Korea, Mongolia, Nepal, New Zealand, Pakistan, Sri Lanka and other countries and territories.[3]

Caspian: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

Central and South America: Argentina, Bolivia, Bolivarian Republic of Venezuela, Brazil, Chile, Colombia, Costa Rica, Cuba, Curaçao, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Suriname, Trinidad and Tobago, Uruguay, and other countries and territories.[4]

China: People's Republic of China, including Hong Kong.

Developing economies: All other countries not included in the "advanced economies" regional grouping.

Eurasia: Caspian regional grouping and the Russian Federation.

Europe: European Union regional grouping and Albania, Belarus, Bosnia and Herzegovina, Gibraltar, Iceland, Israel[5], Kosovo, Montenegro, Norway, Serbia, Switzerland, the Former Yugoslav Republic of Macedonia, the Republic of Moldova, Turkey and Ukraine.

European Union: Austria, Belgium, Bulgaria, Croatia, Cyprus[1,2], Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, the Slovak Republic, Slovenia, Spain, Sweden and the United Kingdom.

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1. Note by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

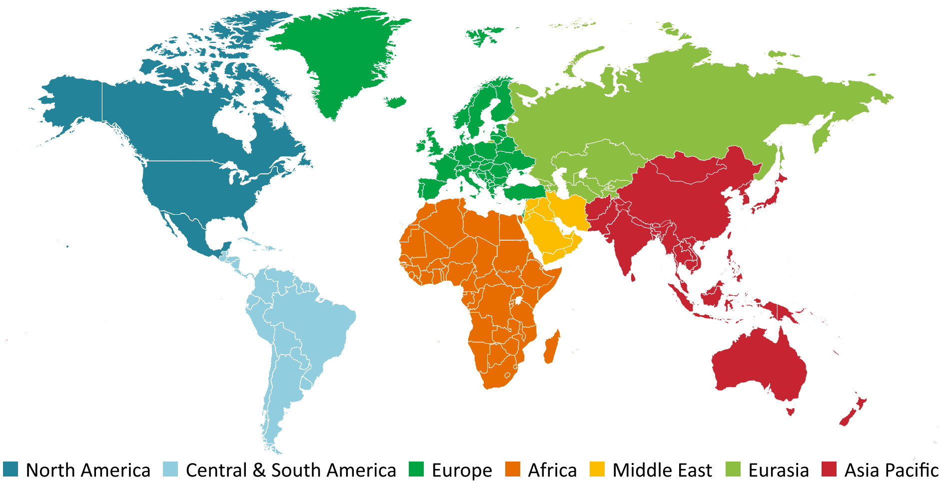
2. Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

3. Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, the Lao People's Democratic Republic, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste and Tonga and Vanuatu.

4. Individual data are not available and are estimated in aggregate for: Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, Bonaire, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guiana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, Saba, Saint Eustatius, Saint Kitts and Nevis, Saint Lucia, Saint Vincent and the Grenadines, Saint Maarten, Turks and Caicos Islands.

5. The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Figure C.2 ▷ *World Energy Outlook* main country groupings



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

IEA (International Energy Agency): OECD regional grouping excluding Chile, Iceland, Israel, Latvia, Mexico and Slovenia. Based on membership status as of mid-2017.

Latin America: Central and South America regional grouping and Mexico.

Middle East: Bahrain, the Islamic Republic of Iran, Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, the Syrian Arab Republic, the United Arab Emirates and Yemen.

Non-OECD: All other countries not included in the OECD regional grouping.

North Africa: Algeria, Egypt, Libya, Morocco and Tunisia.

North America: Canada, Mexico and United States.

OECD (Organisation for Economic Co-operation and Development): Australia, Austria, Belgium, Canada, Chile, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Korea, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, the Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey, United Kingdom and United States. Latvia became a member of the OECD in July 2016, and its membership is not yet reflected in *WEO* projections for the OECD.

OPEC (Organization of Petroleum Exporting Countries): Algeria, Angola, Ecuador, Equatorial Guinea, Gabon, Islamic Republic of Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela.

Southeast Asia: Brunei Darussalam, Cambodia, Indonesia, Lao People's Democratic Republic, Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam. These countries are all members of the Association of Southeast Asian Nations (ASEAN).

Sub-Saharan Africa: Angola, Benin, Botswana, Cameroon, Republic of the Congo, Côte d'Ivoire, Democratic Republic of the Congo, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Mauritius, Mozambique, Namibia, Niger, Nigeria, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania, Togo, Zambia, Zimbabwe and other countries and territories.[6]

Abbreviations and Acronyms

APEC	Asia-Pacific Economic Cooperation
ASEAN	Association of Southeast Asian Nations
BEV	battery electric vehicles
CAAGR	compound average annual growth rate
CAFE	corporate average fuel-economy standards (United States)
CBM	coalbed methane
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CEM	Clean Energy Ministerial
CFL	compact fluorescent lamp
CH_4	methane
CHP	combined heat and power; the term co-generation is sometimes used
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CO_2**-eq**	carbon-dioxide equivalent
COP	Conference of Parties (UNFCCC)
CPS	Current Policies Scenario
CSP	concentrating solar power
CTG	coal-to-gas
CTL	coal-to-liquids
DER	distributed energy resources
DSI	demand-side integration
DSR	demand-side response
EOR	enhanced oil recovery
EPA	Environmental Protection Agency (United States)
EU	European Union
EU ETS	European Union Emissions Trading System
EV	electric vehicle
FAO	Food and Agriculture Organization of the United Nations
FDI	foreign direct investment

6. Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cabo Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Réunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland, Uganda and Western Sahara.

FOB	free on board
GDP	gross domestic product
GHG	greenhouse gases
GTL	gas-to-liquids
HDI	human development index
HFO	heavy fuel oil
IAEA	International Atomic Energy Agency
ICT	information and communication technologies
IEA	International Energy Agency
IGCC	integrated gasification combined-cycle
IMF	International Monetary Fund
IOC	international oil company
IPCC	Intergovernmental Panel on Climate Change
LCOE	levelised cost of electricity
LCV	light-commercial vehicle
LED	light-emitting diode
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LULUCF	land use, land-use change and forestry
MER	market exchange rate
MEPS	minimum energy performance standards
NDCs	Nationally Determined Contributions
NEA	Nuclear Energy Agency (an agency within the OECD)
NGLs	natural gas liquids
NGV	natural gas vehicle
NPS	New Policies Scenario
NPV	net present value
NOC	national oil company
NO_X	nitrogen oxides
NPS	New Policies Scenario
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of Petroleum Exporting Countries
PHEV	plug-in hybrid electric vehicles
PLDV	passenger light-duty vehicle
PM	particulate matter
PPA	power purchase agreement
PPP	purchasing power parity
PSH	pumped storage hydropower
PV	photovoltaic
R&D	research and development
RD&D	research, development and demonstration
RRR	remaining recoverable resource
SDS	Sustainable Development Scenario

SME	small and medium enterprises
SO_2	sulfur dioxide
SWH	solar water or solar water heaters
T&D	transmission and distribution
TES	thermal energy storage
TFC	total final consumption
TPED	total primary energy demand
UAE	United Arab Emirates
UN	United Nations
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
URR	ultimately recoverable resources
US	United States
USGS	United States Geological Survey
VRE	variable renewable energy
WACC	weighted average cost of capital
WEO	World Energy Outlook
WEM	World Energy Model
WHO	World Health Organization

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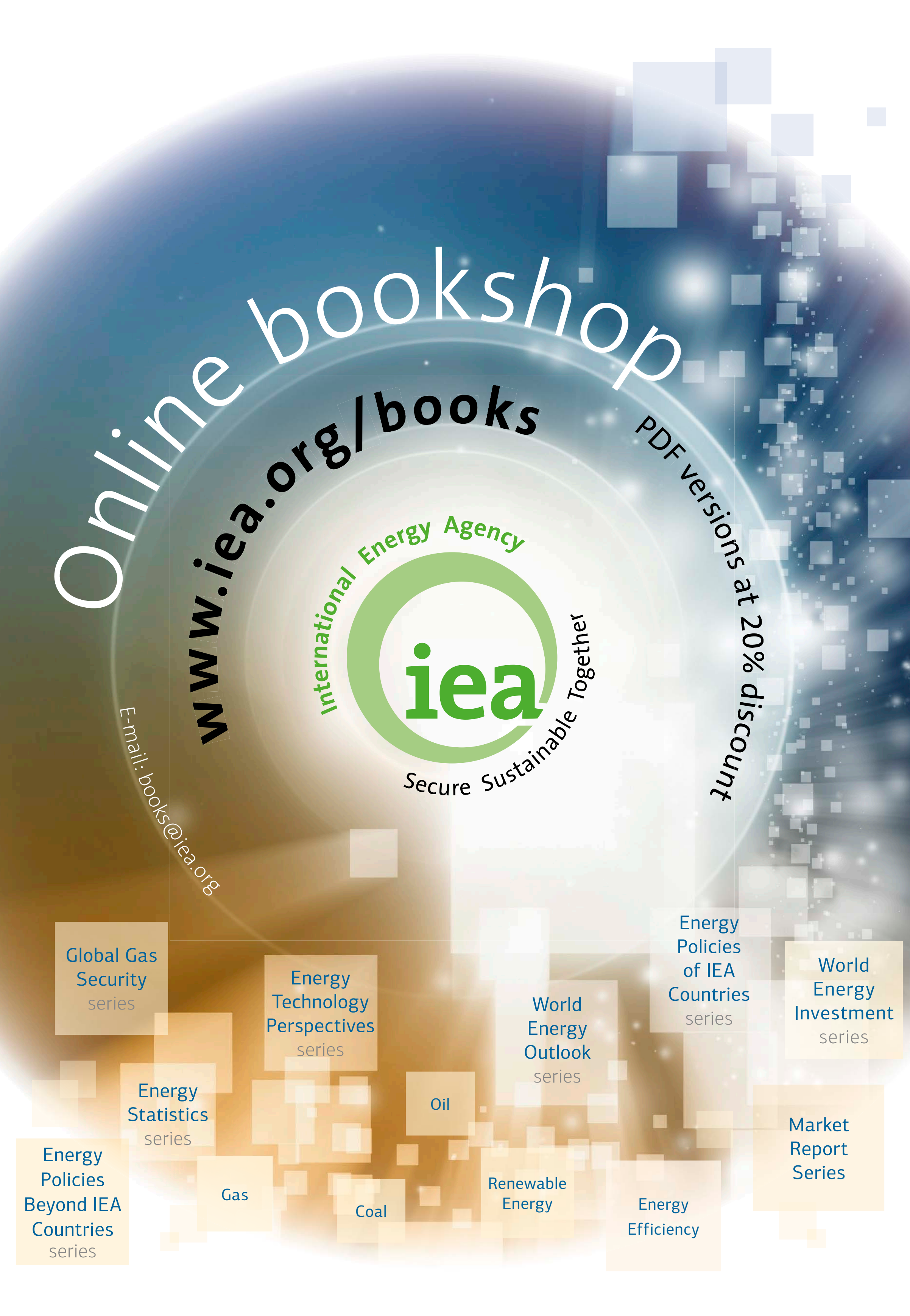
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World Energy Outlook 2017

The global energy scene is in a state of flux. Large-scale shifts include: the rapid deployment and steep declines in the costs of major renewable energy technologies; the growing importance of electricity in energy use across the globe; profound changes in China's economy and energy policy, moving consumption away from coal; and the continued surge in shale gas and tight oil production in the United States.

These changes provide the backdrop for the *World Energy Outlook-2017*, which includes a full update of energy demand and supply projections to 2040 based on different scenarios. The projections are accompanied by detailed analyses of their impact on energy industries and investment, as well as implications for energy security and the environment.

The report this year includes a focus on China, which examines how China's choices could reshape the global outlook for all fuels and technologies. A second focus, on natural gas, explores how the rise of shale gas and LNG are changing the global gas market as well as the opportunities and risks for gas in the transition to a cleaner energy system.

Finally, the *WEO-2017* introduces a major new scenario – the Sustainable Development Scenario – that outlines an integrated approach to achieving internationally agreed objectives on climate change, air quality and universal access to modern energy.

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